UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 24, 2015

ENERGY TRANSFER EQUITY, L.P.

(Exact name of Registrant as specified in its charter)

Delaware	**001-32740**	**30-0108820**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification Number)**

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)

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

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

This Current Report on Form 8-K is being filed principally to reflect certain retrospective revisions for changes in reportable segments that have been made to the consolidated financial statements of Energy Transfer Equity, L.P. ("ETE" or the "Partnership") that were previously filed with the Securities and Exchange Commission by the Partnership on March 2, 2015 as Items 1, 6, 7 and 8 to its Annual Report on Form 10-K for the year ended December 31, 2014 (the "2014 Form 10-K"). ETE began reporting comparative results using the revised segment presentation effective with the filing of its Quarterly Report on Form 10-Q for the period ended June 30, 2015.

As a result of the transaction that was consummated between Energy Transfer Partners, L.P. ("ETP") and Regency Energy Partners LP ("Regency") in April 2015, ETE's reportable segments in its consolidated financial statements were re-evaluated. Beginning with ETE's Form 10-Q for the period ended June 30, 2015, ETE's reportable segments now consist of the following:

- Investment in ETP, including the consolidated operations of ETP and Regency;
- Investment in Lake Charles LNG, including the operations of Lake Charles LNG Company, LLC; and
- Corporate and Other

In order to preserve the nature and character of the disclosures set forth in the 2014 Form 10-K, the items included in this Form 8-K have been updated solely for matters relating specifically to the realignment of ETE's reportable segments, as described above. In addition, unit and per-unit amounts have been adjusted to reflect the impact of a two-for-one unit split that occurred in July 2015. No attempt has been made in the audited financial statements included in Exhibit 99.1 in this Form 8-K, and it should not be read, to modify or update other disclosures as presented in the 2014 Form 10-K to reflect events or occurrences after the date of the filing of the 2014 Form 10-K, March 2, 2015. Therefore, this Form 8-K should be read in conjunction with the 2014 Form 10-K, and filings made by ETE with the SEC subsequent to the filing of the 2014 Form 10-K, including ETE's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2015 filed on August 7, 2015.

Item 9.01 of this Current Report on Form 8-K revises certain information contained in ETE's 2014 Form 10-K to reflect these changes in reportable segments. In particular, Exhibit 99.1 contains a revised description of the ETE's business segments, financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 9.01 Financial Statements and Exhibits.

See the Exhibit Index set forth below for a list of exhibits included with this Form 8-K.

Exhibit Number	Description
23.1	Consent of Grant Thornton LLP related to Energy Transfer Equity, L.P.
23.2	Consent of Ernst & Young LLP related to Sunoco Logistics Partners L.P.
23.3	Consent of Ernst & Young LLP related to Susser Holdings Corporation
23.4	Consent of Ernst & Young LLP related to Sunoco LP
99.1	Revised Energy Transfer Equity, L.P. description of the business, financial statements as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.2	Report of Ernst & Young LLP on consolidated financial statements of Sunoco Logistics Partners L.P.
99.3	Report of Ernst & Young LLP on consolidated financial statements of Susser Holdings Corporation
99.4	Report of Ernst & Young LLP on consolidated financial statements of Sunoco LP
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Energy Transfer Equity, L.P.
By: LE GP, LLC,
its general partner

Date: November 24, 2015

/s/ Jamie Welch
Jamie Welch
Group Chief Financial Officer

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 2, 2015, except for all unit and per unit amounts as discussed in Note 9 and for Note 16, as to which the date is November 24, 2015, with respect to the consolidated financial statements included in this Current Report of Energy Transfer Equity, L.P. on Form 8-K. 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
November 24, 2015

Exhibit 23.2

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 Long-Term Incentive Plan of Energy Transfer Equity, L.P.

of our report dated March 1, 2013, with respect to the consolidated statements of comprehensive income, equity and cash flows of Sunoco Logistics Partners L.P., included in this Current Report (Form 8-K) of Energy Transfer Equity, L.P. which includes the adjusted consolidated financial statements of Energy Transfer Equity, L.P. for the consolidation of an entity under common control.

/s/Ernst & Young LLP

Philadelphia, Pennsylvania
November 24, 2015

Exhibit 23.3

CONSENT OF INDEPENDENT AUDITORS

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 Long-Term Incentive Plan of Energy Transfer Equity, L.P.

of our report dated February 28, 2015 (except for Note 2, as to which the date is April 30, 2015), with respect to the consolidated financial statements of Susser Holdings Corporation (not presented separately herein), included in this Current Report on Form 8-K of Energy Transfer Equity, L.P..

/s/ Ernst & Young LLP

Houston, Texas
November 18, 2015

Exhibit 23.4

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 Long-Term Incentive Plan of Energy Transfer Equity, L.P.

of our report dated February 27, 2015, with respect to the consolidated financial statements of Sunoco LP (not presented separately herein), included in this Current Report on Form 8-K of Energy Transfer Equity, L.P..

/s/Ernst & Young LLP

Houston, Texas
November 18, 2015

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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, LLC which owns 100% of FGT
Coal Handling	Coal Handling Solutions LLC, Kingsport Handling LLC and Kingsport Services LLC, now known as Materials Handling Solutions LLC
CrossCountry	CrossCountry Energy, LLC
CFTC	Commodities Futures Trading Commission
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
Eagle Rock	Eagle Rock Energy Partners, L.P.
Enterprise	Enterprise Products Partners L.P., together with its subsidiaries
EPA	U.S. Environmental Protection Agency
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 Holdco	ETP Holdco Corporation
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
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.
HOLP	Heritage Operating, L.P.
Hoover Energy	Hoover Energy Partners, LP
IDRs	incentive distribution rights
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC)
LCL	Lake Charles LNG Export Company, LLC, a subsidiary of ETP and ETE
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
LNG Holdings	Lake Charles LNG Holdings, LLC
LPG	liquefied petroleum gas
Lone Star	Lone Star NGL LLC
MACS	Mid-Atlantic Convenience Stores, LLC
MEP	Midcontinent Express Pipeline LLC
MGE	Missouri Gas Energy
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
PCBs	polychlorinated biphenyls
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC
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 Logistics	Sunoco Logistics Partners L.P.
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Susser	Susser Holdings Corporation
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, a subsidiary of Panhandle
WTI	West Texas Intermediate Crude

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, depletion, 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). 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.

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, Inc., Sunoco Logistics, Sunoco LP, Susser and ETP Holdco. References to the “Parent Company” mean Energy Transfer Equity, L.P. on a stand-alone basis.

During 2014, our consolidated subsidiaries, Trunkline LNG Company, LLC, Trunkline LNG Export, LLC and Susser Petroleum Partners LP, changed their names to Lake Charles LNG Company, LLC, Lake Charles LNG Export, LLC and Sunoco LP, respectively. All references to these subsidiaries throughout this document reflect the new names of those subsidiaries, regardless of whether the disclosure relates to periods or events prior to the dates of the name changes.

In January 2014 and July 2015, the Partnership completed two-for-one splits 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 splits 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 ETP Holdco at the time of ETP’s acquisition of Sunoco, Inc. on October 5, 2012. On April 30, 2013, ETP acquired ETE’s 60% interest in ETP Holdco.

All information in this document is reported as of March 2, 2015, the date the Partnership’s Form 10-K for the year ended December 31, 2014 was originally filed, except for (i) information where the context specifically states otherwise (e.g., fiscal year end information reported as of December 31, 2014), (ii) information related to the Regency Merger and the resulting segment change, and (iii) unit or per-unit amounts that have been adjusted for the July 2015 unit split, as discussed above.

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, and the Partnership’s ownership of Lake Charles LNG.

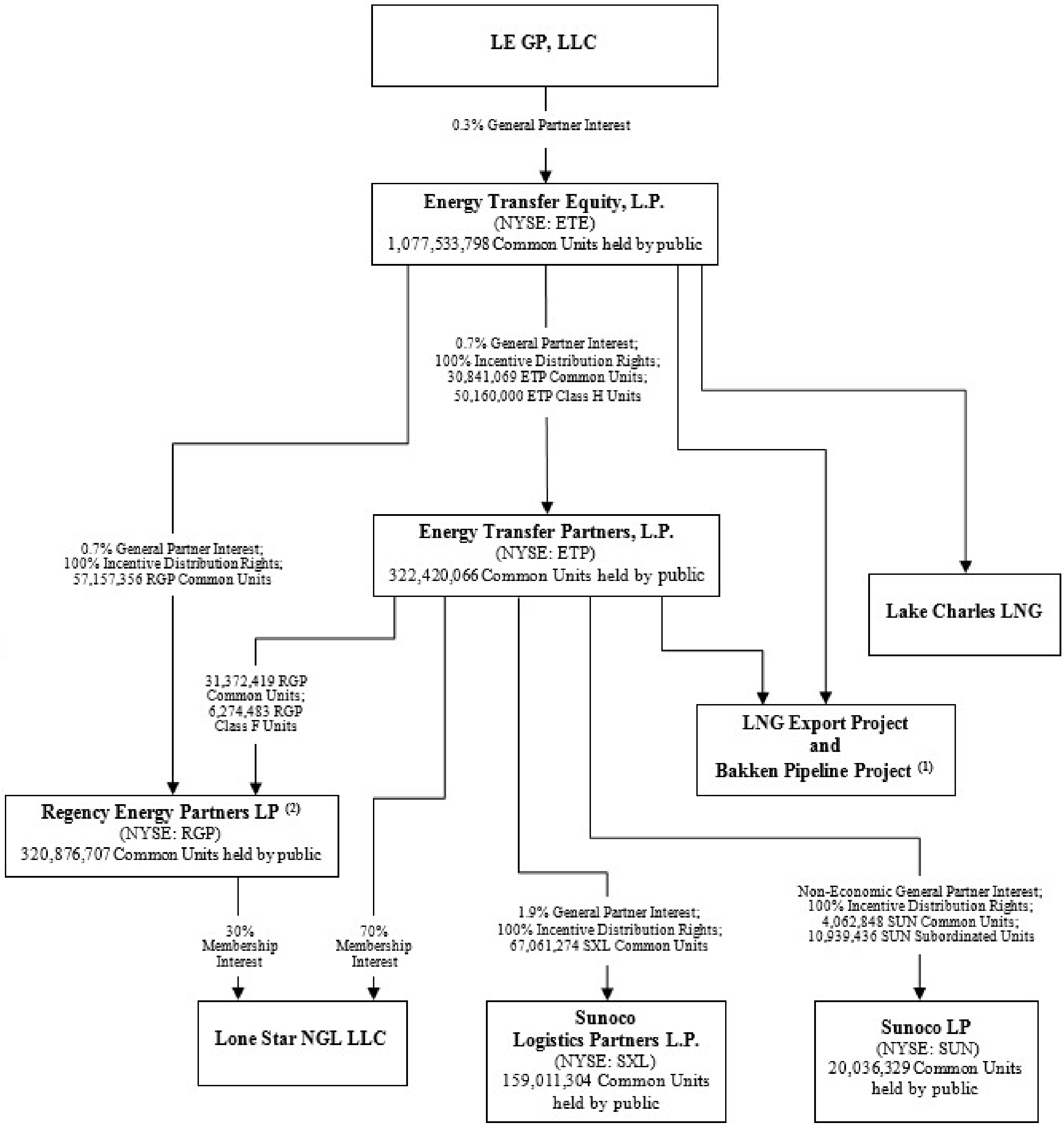
At December 31, 2014, our interests in ETP and Regency consisted of 100% of the respective general partner interests and IDRs, as well as the following:

	ETP	Regency
Units held by wholly-owned subsidiaries:		
Common units	30,841,069	57,157,356
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.

Organizational Structure

The following chart summarizes our organizational structure as of December 31, 2014. For simplicity, certain immaterial entities and ownership interests have not been depicted.



(1) Pursuant to an agreement between ETE and ETP entered into in December 2014, ETE agreed to transfer its 45% equity interest in the Bakken Pipeline Project to ETP. This transaction closed in March 2015.

(2) As discussed below, in April 2015, ETP and Regency completed their previously announced merger.

Significant Achievements in 2014 and Beyond

Strategic Transactions

Our significant strategic transactions in 2014 and beyond included the following, as discussed in more detail herein:

- In April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the "Regency Merger"). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new ETP Series A Preferred Units.

- In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE's 45% interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline (collectively, the "Bakken pipeline project"), and $879 million in cash (less amounts funded prior to closing by ETE for capital expenditures for the Bakken pipeline project) in exchange for 30.8 million newly issued ETP Class H Units that, when combined with the 50.2 million previously issued ETP Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics. In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016.

- In October 2014, Sunoco LP acquired MACS from a subsidiary of ETP in a transaction valued at approximately $768 million. The transaction included approximately 110 company-operated retail convenience stores and 200 dealer-operated and consignment sites from MACS.

- In August 2014, ETP and Susser completed the merger of an indirect wholly-owned subsidiary of ETP, with and into Susser, with Susser surviving the merger as a subsidiary of ETP for total consideration valued at approximately $1.8 billion (the "Susser Merger").

- In July 2014, Regency acquired Eagle Rock's midstream business for $1.3 billion, including the issuance of 8.2 million Regency common units to Eagle Rock and the assumption of $499 million of Eagle Rock's 8.375% senior notes due 2019 (the "Eagle Rock Acquisition"). The remainder of the purchase price was funded by $400 million in common units issued to ETE and borrowing under Regency's revolving credit facility. This acquisition complements Regency's core gathering and processing business, and when combined with the PVR Acquisition, further diversifies Regency's basin exposure in the Texas Panhandle, east Texas and south Texas.

- In March 2014, Regency acquired PVR for a total purchase price of $5.7 billion, including $1.8 billion principal amount of assumed debt (the "PVR Acquisition"). PVR unitholders received (on a per unit basis) 1.02 Regency Common Units and a one-time cash payment of $36 million, which was funded through borrowings under Regency's revolving credit facility. The PVR Acquisition enhanced 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.

- In February 2014, ETP completed the transfer to ETE of Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, 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 2014, ETP sold 18.9 million of the AmeriGas common units that ETP originally received in connection with the contribution of ETP's Propane Business to AmeriGas in January 2012.

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 of 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 merger of ETP and Regency in 2015, our reportable segments were re-evaluated and currently reflect the following reportable segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Lake Charles LNG, including the operations of Lake Charles LNG; and
- Corporate and Other, including the activities of the Parent Company.

The businesses within these segments are described below. See Note 16 to our consolidated financial statements for additional financial information about our reportable segments.

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 7,700 miles of natural gas transportation pipelines with approximately 14.1 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas.

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

ETP's intrastate transportation and storage operations' results are determined primarily by the amount of capacity its 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.

Through Regency, ETP 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.

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. Generally, ETP purchases natural gas from either the market (including purchases from our marketing operations) or from producers at the wellhead. To the extent the natural gas comes from producers, it is primarily purchased at a discount to a specified market price and typically resold to customers based on an index price. In addition, 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 per day of transportation capacity and has 50% interests in the joint ventures that own the 185-mile Fayetteville Express pipeline and the 500-mile Midcontinent 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.

Through Regency, ETP owns a 50% interest in the MEP pipeline system, operated by KMI, and has the capability to transport up to 1.8 Bcf/d of natural gas, and the pipeline capacity is nearly fully subscribed, Zone 1 is 95% subscribed and Zone 2 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.

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

The results from ETP's interstate transportation and storage operations are primarily derived from the fees ETP earns from natural gas transportation and storage services.

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.

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

Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and to continue to produce for longer periods of time. As the pressure of a well declines, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Field compression is typically used to lower the pressure of a gathering system. If field compression is not installed, then the remaining production in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise might not be produced.

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

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

Through ETP's midstream operations, ETP owns and operates approximately 32,900 miles of in service natural gas and NGL gathering pipelines with approximately 5.7 Bcf/d of gathering capacity, 21 natural gas processing plants, 27 natural gas treating facilities and 4 natural gas conditioning facilities with an aggregate processing, treating and conditioning capacity of approximately 9.4 Bcf/d. ETP's midstream operations focus on the gathering, compression, treating, blending, and processing, and ETP's 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.

ETP's midstream operations also include Regency's 60% interest in Edwards Lime Gathering LLC, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in south Texas, Regency's 33.33% membership interest in Ranch Westex JV LLC, which processes natural gas delivered from the NGLs-rich shale formations in west Texas, Regency's 50% interest in Sweeny Gathering LP, which operates a natural gas gathering facility in south Texas, Regency's 51% membership interest in Aqua - PVR Water Services, LLC, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, Regency's 75% membership interest in Ohio River System LLC, which will operate a natural gas gathering system in the Utica shale in Ohio, and Regency's 50% interest in Mi Vida JV LLC, which will operate a cryogenic processing plant and related facilities in west Texas.

ETP’s midstream operations’ results are derived primarily from margins earned for natural gas volumes that are gathered, transported, purchased and sold through its pipeline systems and the natural gas and NGL volumes processed at its processing and treating facilities.

Liquids 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 liquids transportation and services operations ETP owns 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, four NGL and propane fractionation facilities with an aggregate capacity of 325,000 Bbls/d and NGL storage facilities with aggregate working storage capacity of approximately 53 million Bbls. Three NGL and propane fractionation facilities and the NGL storage facilities are located at Mont Belvieu, Texas, one NGL 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 joint venture that owns the Liberty pipeline, an approximately 87-mile NGL pipeline and the recently converted 83-mile Rio Bravo crude oil pipeline.

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

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

These operations also include revenues earned from processing and fractionating refinery off-gas. Under these contracts ETP receives an Olefins-grade (“O-grade”) stream from cryogenic processing plants located at refineries and fractionate the products into their pure components. ETP delivers purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, ETP has percent-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percent-of-proceeds contracts, ETP retains a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion ETP retains as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion ETP retains as a fee. Under ETP’s income sharing contracts, ETP pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and olefins prices increase in relation to natural gas prices, the value of the percent ETP retains as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent ETP retains as a fee.

ETP’s Investment in Sunoco Logistics

ETP’s interests in Sunoco Logistics consist of a 1.9% general partner interest, 100% of the IDRs and 67.1 million Sunoco Logistics common units representing 29.7% of the limited partner interests in Sunoco Logistics as of December 31, 2014. Because ETP controls Sunoco Logistics through its ownership of the general partner, the operations of Sunoco Logistics are consolidated into ETP.

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 expanded its operations of pipeline transportation, acquisition, storage and marketing of NGLs. In addition, Sunoco Logistics has ownership interests in several product pipeline joint ventures.

Sunoco Logistics' crude oil pipelines transport crude oil in the southwest and midwest United States, principally in Oklahoma and Texas. Sunoco Logistics' crude oil pipelines consist of approximately 5,300 miles of crude oil trunk pipelines for high-volume, long-distance transportation 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 proprietary fleet of approximately 335 crude oil transport trucks and approximately 135 crude oil truck unloading facilities as well as third-party assets.

Sunoco Logistics' terminal facilities consist of crude oil, refined products and NGL terminals which receive 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 48 million barrels, including the 25 million barrel Nederland, Texas crude oil terminal; the 6 million barrel Eagle Point, New Jersey refined products and crude oil terminal; the 3 million barrel Marcus Hook, Pennsylvania refined products and NGL facility (the "Marcus Hook Industrial Complex"); approximately 39 active refined products marketing terminals located in the northeast, midwest and southwest United States; and refinery terminals located in the northeast United States.

Sunoco Logistics' product pipelines transport refined products and NGLs 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' products pipelines consist of approximately 2,400 miles of refined products and NGL pipelines and joint venture interests in four products pipelines in selected areas of the United States.

Retail Marketing Operations

ETP's retail marketing business operations are conducted through various wholly-owned subsidiaries as well as through Sunoco LP, which ETP controls through its ownership of the general partner.

ETP's retail marketing and wholesale distribution operations include the following activities conducted in 30 states, primarily on the east cost, midwest and south regions of the United States:

- Sale of motor fuel (gasoline and diesel) and merchandise at company-operated retail locations and branded convenience stores.
- Distribution of gasoline, diesel and other petroleum products to convenience stores, independent dealers, distributors and other commercial customers.

ETP's Other Operations and Investments

ETP's other operations and investments include the following:

- Sunoco, Inc. 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, Inc. has a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.
- 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. ETP also attracts other customers by marketing volumes of natural gas that do not move through its assets, referred to as off-system gas. For both on-system and off-system gas, ETP purchases natural gas from natural gas producers and other suppliers 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 of natural gas, less the costs of transportation. For the off-system gas, ETP purchases gas or acts as an agent for small independent producers that may not have marketing 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 100% of the membership interests of 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 a 40% interest in LCL, which is developing a LNG liquefaction project.
- Through Regency, ETP owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. Through Regency, ETP 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.

- Through Regency, ETP is involved in the management of coal and natural resources properties and the related collection of royalties. Through Regency, ETP also earns revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. These operations also included Regency's 50% interesting in Coal Handling, which owns and operates end-user coal handling facilities. Regency purchased the remaining 50% interest in Coal Handling effective December 31, 2014.

Investment in Lake Charles LNG

Lake Charles LNG provides terminal services for shippers by receiving LNG at the facility for storage and delivering such LNG to shippers, either in liquid state or gaseous state after regasification. Lake Charles LNG derives all of its revenue from a series of long term contracts with a wholly-owned subsidiary of BG Group plc ("BG").

Lake Charles LNG is currently developing a planned liquefaction facility with BG for the export of LNG.

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 2017.

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 3,800 miles of natural gas pipeline
- Bammel storage facility with 52.5 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 a 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 52.5 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, 2014, ETP had approximately 9.3 Bcf committed under fee-based arrangements with third parties and approximately 40.2 Bcf stored in the facility for ETP's own account.

East Texas Pipeline

- Capacity of 2.4 Bcf/d
- Approximately 370 miles of natural gas pipeline

The East Texas pipeline connects three treating facilities, one of which ETP owns, with ETP's Southeast Texas System. The East Texas pipeline serves producers in East and North Central Texas and provides access to the Katy Hub. The East Texas pipeline includes 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.

RIGS Haynesville Partnership Co.

- Capacity of 2.1 Bcf/d
- Approximately 450 miles of natural gas pipeline
- Regency owns a 49.99% general partner interest

RIGS is a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets.

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 65% 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.

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 ETP Holdco.

Trunkline Gas Company

- 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 ETP 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 KMI

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.

Midcontinent Express Pipeline LLC

- Capacity of 1.8 Bcf/d
- Approximately 500 miles of interstate natural gas pipeline
- Regency owns a 50% interest

MEP owns a 500-mile interstate pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipeline System in Butler, Alabama.

Gulf States

- Capacity of 140,000 MMBtu/d
- Approximately 10 miles of interstate natural gas pipeline

Gulf States owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

Midstream

The following details the assets in ETP's midstream operations:

Southeast Texas System

- Approximately 6,400 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 NGL pipelines and then to Lone Star.

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 1,160 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's 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's NGL pipelines for delivery of NGLs to Lone Star.

Regency Arklatex System

- Approximately 2,800 miles of natural gas pipeline
- Four cryogenic natural gas processing facilities, two refrigeration plants, a conditioning plant and two amine treating plants

Regency's Arklatex assets gather, compress, treat and dehydrate natural gas in several Parishes of north and west Louisiana and several counties in east Texas. These assets also include cryogenic natural gas processing facilities, a refrigeration plant, a conditioning plant, amine treating plants, and an interstate NGL pipeline.

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.

In May 2014, Regency announced the construction of a new 200 MMcf/d cryogenic processing plant and 47-mile, 40,000 bbls/d capacity NGL pipeline, for a combined total of $191 million, which is expected to be completed in mid-2015.

Regency South Texas System

- Approximately 1,700 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. The pipeline systems are connected to third-party processing plants and Regency's treating facilities that include acid gas reinjection wells 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, including the Frio, Vicksburg, Miocene, Canyon Sands and Wilcox formations, and the NGLs-rich and oil-rich Eagle Ford shale formation.

Regency owns a 60% interest in Edwards Lime Gathering LLC with Talisman Energy USA Inc. and Statoil Texas Onshore Properties LP owning 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.

Regency Permian System

- Approximately 7,820 miles of natural gas pipeline
- Six processing and treating plants, two processing plants and two treating plants

Regency's Permian Basin gathering system assets offer wellhead-to-market services to producers in the Texas counties of Ward, Winkler, Reeves, Pecos, Crocket, Upton, Crane, Ector, Culberson, Reagan and Andrews, as well as into Eddy and Lea counties in New Mexico which surround the Waha Hub, one of Texas's 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 Regency gathers and processes, 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.

In October 2014, Regency entered into a joint venture with Anadarko Mi Vida LLC ("Anadarko"). Anadarko and Regency each own a 50% membership interest in the new joint venture, Mi Vida JV LLC. Regency will construct and operate a 200 MMcf/d cryogenic processing plant and related facilities in west Texas, on behalf of Mi Vida JV LLC.

Regency 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.

Regency Mid-Continent Region

- Approximately 13,000 miles of natural gas pipeline
- 14 processing facilities

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 and the Texas Panhandle. 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. Regency has 14 natural gas producing facilities and approximately 12,995 miles of gathering pipeline.

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.

Regency Eastern Region

- Approximately 370 miles of natural gas pipeline

Regency's eastern region assets are located in Pennsylvania, Ohio, and West Virginia, and gather natural gas from the Marcellus and Utica basins. Regency's eastern gathering assets include approximately 370 miles of natural gas gathering pipeline, natural gas trunkline pipelines, and fresh water pipelines, and the Lycoming, Wyoming, East Lycoming, Bradford, Green County, and Preston gathering and processing systems.

Regency also own a 51% membership interest in Aqua - PVR Water Services, LLC, a joint venture that transports and supplies fresh water to natural gas producers drilling in the Marcellus Shale in Pennsylvania.

In August 2014, Regency entered into a joint venture with American Energy - Midstream, LLC ("AEM"). Regency and AEM own a 75% and 25% membership interest, respectively, in the new joint venture Ohio River System LLC ("ORS"). On behalf of ORS, Regency is constructing and will operate its Ohio Utica River System, (the "ORS System") which consists of a 52-mile, 36-inch gathering trunkline that will be capable of delivering up to 2.1 bcf/d to Rockies Express Pipeline ("REX") and Texas Eastern Transmission, and potentially others and the construction of 25,000 horsepower of compression at the REX interconnect. This project will also include the construction of a 12-mile, 30-inch lateral that will initially connect to the tailgate of the Cadiz processing plant and Harrison County wellhead production. The system is expected to be completed in the third quarter of 2015. Total costs for the ORS System are expected to be approximately $500 million; 75% contributed from Regency and 25% contributed from AEM. Additionally, Regency and American Energy - Utica, LLC ("AEU"), an affiliate of AEM, entered into a gathering agreement for gas produced from the Utica Shale in eastern Ohio by AEU.

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 and the recently commissioned Rebel processing plant with capacity of 130 MMcf/d. ETP also owns approximately 50 miles of gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

Liquids Transportation and Services

The following details ETP's assets in the liquids transportation and services operations. Certain assets, as discussed below, are owned by Lone Star, a joint venture with Regency in which ETP has a 70% interest.

West Texas System

- Capacity of 137,000 Bbls/d
- Approximately 1,170 miles of NGL transmission pipelines

The West Texas System, owned by Lone Star, is an intrastate NGL pipeline consisting of 3-inch to 16-inch long-haul, mixed NGLs transportation pipeline that delivers 137,000 Bbls/d of capacity from 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.

Rio Bravo Pipeline

- Aggregate capacity of 100,000 Bbls/d
- Approximately 83 miles of crude oil transmission pipeline

In 2014, ETP converted approximately 80 miles of natural gas pipeline from the HPL and Southeast Texas Systems to crude service and constructed approximately 3 miles of new crude oil pipeline.

Mont Belvieu Facilities

- Working storage capacity of approximately 48 million Bbls
- Approximately 185 miles of NGL transmission pipelines
- 300,000 Bbls/d NGL and propane fractionation facilities

The Mont Belvieu storage facility, owned by Lone Star, is an integrated liquids storage facility with over 48 million Bbls of salt dome 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 October 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 4.5 million Bbls

The Hattiesburg storage facility, owned by Lone Star, is an integrated liquids storage facility with approximately 4.5 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 the assets in ETP's investment in Sunoco Logistics:

Crude Oil Pipelines

Sunoco Logistics' crude oil pipelines consist of approximately 5,300 miles of crude oil trunk pipelines for high-volume, long-distance transportation 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 3,150 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 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. In December 2014, Sunoco Logistics acquired an additional 28.3% ownership interest in the West Texas Gulf Pipe Line Company from Chevron Pipe Line Company, increasing its controlling financial interest in the consolidated subsidiary to 88.6%. The remaining 11.4% was acquired from Southwest Pipeline Holding Company, LLC in January 2015.

  The Southwest United States pipeline system also includes the Oklahoma crude oil pipeline and gathering system that consists of approximately 1,050 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 Sunoco Logistics' assets, which include approximately 335 crude oil transport trucks and approximately 135 crude oil truck unloading facilities, as well as third-party truck, rail and marine assets. 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;
- 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 third parties and certain affiliates, 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.

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, 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 and NGLs. The terminal receives, stores, and distributes crude oil, NGLs, 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 25 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 DOE. 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 DOE. The Nederland Terminal can also receive NGLs in connection with the Mariner South pipeline.

- *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 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.

  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, which is operated by PES. 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 Industrial Complex:* In 2013, Sunoco Logistics acquired Sunoco, Inc.'s Marcus Hook Industrial Complex. The acquisition included terminalling and storage assets with a capacity of approximately 3 million barrels located in Pennsylvania and Delaware, including approximately 2 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 Industrial Complex also provides customers with the use of industrial space and equipment at the facility, as well as logistical, utility and infrastructure services.

- *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 marine vessels (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 6 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 NGLs from local producers and a refinery in western Ohio. The terminal can receive and ship by pipeline in both directions and has a truck loading and offloading 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.

Products Pipelines

Sunoco Logistics owns and operates approximately 2,400 miles of products pipelines in several regions of the United States. The products pipelines primarily transport refined products and NGLs 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 approximately 350 miles of products pipelines owned by Sunoco Logistics' consolidated joint venture, Inland Corporation ("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 products pipelines are regulated by the FERC and the Pennsylvania Public Utility Commission ("PA PUC"), among other state regulatory agencies.

- *Mariner East:* Mariner East 1 and Mariner East 2 are pipeline projects to deliver NGLs from the Marcellus and Utica Shale areas in western Pennsylvania, West Virginia and eastern Ohio to the Marcus Hook Industrial Complex on the Delaware River in Pennsylvania, where it will be processed, stored and distributed to various local, domestic and waterborne markets. Mariner East 2 is the second phase of the project, which will expand the total take-away capacity to 345,000 Bbls/d. Mariner East 1 commenced initial operations in the fourth quarter of 2014 and Mariner East 2 is expected to commence operations in the fourth quarter 2016.

- *Mariner Souther:* The Mariner South pipeline provides transportation of propane and butane products from the Mont Belvieu, Texas area to the Nederland Terminal, where such products can be sold by way of ship. Mariner South commenced initial operations in December 2014, with an initial capacity of 200,000 Bbls/d of NGLs and other products.

- *Inland:* Inland is Sunoco Logistics' 83.8% owned joint venture consisting of approximately 350 miles of active 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 products pipelines, summarized in the following table:

Pipeline	Equity Ownership	Pipeline Mileage
Explorer Pipeline Company(1)	13.3%	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. An additional 3.9% ownership interest was purchased in the first quarter of 2014.

(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 and wholesale distribution operations consist of the retail sale of motor fuel and merchandise through company-operated locations, and the distribution of branded and unbranded motor fuel purchased primarily from refiners to company-operated retail sites, independently-operated retail sites, as well as other wholesale and commercial customers.

The business is operated through various wholly-owned subsidiaries as well as through Sunoco LP which ETP controls through its ownership of the general partner. ETP currently plans to contribute all of the retail operations and fuel distributions business to Sunoco LP in future periods. In October 2014, ETP completed the first of such transactions, when one of ETP's subsidiaries contributed all of the ownership of MACS to Sunoco LP.

The retail marketing operations have a portfolio of outlets operating under three channels of trade: company-operated, dealer-operated and distributor-operated sites. The portfolio of sites in these channels differ in various ways including: site ownership and operation, product distribution to the outlets, and types/brands of products and services provided.

Company-operated sites, which are operated by one of our subsidiaries, and independent dealer-operated sites are sites at which fuel products are delivered directly to the site by company-operated trucks or by contract carriers. One of our subsidiaries may own or lease the property and collect rental income or an independent dealer owns or leases the property. Independent dealers are supplied under a contract with one of our subsidiaries. Most of the company-operated sites include a convenience store under the Aplus®, Stripes®, MACS, Tigermarket or Aloha Island Mart® brands. As of December 31, 2014, our subsidiaries were operating or supplying under a long-term contract a total of 75 Sunoco®-branded outlets on turnpikes and expressways in Pennsylvania, New Jersey, New York, Maryland, Ohio and Delaware.

Distributor outlets are primarily Sunoco®-branded sites in which the distributor takes delivery of fuel products at a terminal where branded products are available. ETP subsidiaries supply the distributor under a long-term contract, but do not own, lease or operate these distributor locations.

The highest concentration of retail outlets are located in Texas, Pennsylvania, New York, Florida and Ohio.

The following table sets forth ETP's retail gasoline outlets at December 31, 2014 (including sites operated through its subsidiaries):

Retail and Fuel Distribution Outlets:	Sunoco LP	Wholly-Owned Subsidiaries	Total
Company-Owned or Leased:			
Company-Operated[1]	155	1,096	1,251
Dealer-Operated	138	425	563
Total	293	1,521	1,814
Dealer Owned	655	541	1,196
Distributor Outlets	—	3,640	3,640
Total	948	5,702	6,650

(1) Gasoline and diesel throughput per company-operated site averaged 177,236 gallons per month during 2014.

Brands

ETP manages a portfolio of strong proprietary fuel and convenience store brands through its retail and wholesale portfolio of outlets, including Sunoco®, Stripes®, Aplus®, and Aloha Island Mart®.

Of the total retail outlets that are company-operated or operating under a long-term contract by an independent third-party, 4,961 operate under the Sunoco® fuel brand as of December 31, 2014. The Sunoco® brand is positioned as a premium fuel brand. Brand improvements in recent years have focused on physical image, customer service and product offerings. In addition, Sunoco, Inc. believes its brands and high performance gasoline business have benefited from its sponsorship agreements with NASCAR®, INDYCAR® and the NHRA®. Under the sponsorship agreement with NASCAR®, which continues until 2022, Sunoco® is the Official Fuel of NASCAR® and APlus® is the Official Convenience Store of NASCAR®. Sunoco, Inc. has exclusive rights to use certain NASCAR® trademarks to advertise and promote Sunoco, Inc. products and is the exclusive fuel supplier for the three major NASCAR® racing series. The sponsorship agreements with INDYCAR® and NHRA® continue through 2018 and 2024, respectively.

In addition to operating premium proprietary brands, our subsidiaries operate as a significant distributor to multiple top-tier fuel brands, including Exxon®, Mobil®, Valero®, Shell® and Chevron®.

Convenience Store and Restaurant Operations

ETP subsidiaries operate 1,185 convenience stores primarily under our proprietary Stripes®, Aplus® and Aloha Island Mart® convenience store brands as of December 31, 2014. These stores complement sales of fuel products with a broad mix of merchandise, food service, and other services. As of December 31, 2014, 474 of these stores featured in-store restaurants allowing us to make fresh food on the premises daily. Laredo Taco Company® is ETP's in-house proprietary restaurant operation featuring breakfast and lunch tacos, a wide variety of handmade authentic Mexican food and other hot food offerings targeted to local populations in the markets served. Some of these stores also offer other proprietary and third party food options, including Subway® sandwiches and Godfather® pizza.

The following table sets forth information concerning the company-operated convenience stores during 2014:

Number of stores at December 31, 2014		1,185
Merchandise sales (thousands of dollars/store/month)	$	127
Merchandise margin (% sales)		31.4%

ETP's retail marketing operations also include the distribution of gasoline, distillate and other petroleum products to wholesalers, unbranded retailers and other commercial customers.

ETP's Other Operations and Investments

Contract Services Operations

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.

Natural Resources Operations

Regency's Natural Resources operations primarily involve the management and leasing of coal properties and the subsequent collection of royalties. Regency also earns revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage fees. As of December 31, 2014, Regency owned or controlled approximately 821 million tons of proven and probable coal reserves in central and northern Appalachia, properties in eastern Kentucky, Tennessee, southwestern Virginia and southern West Virginia; and the Illinois Basin, properties in southern Illinois, Indiana, and western Kentucky and as the operator of end-user coal handling facilities. Since 2004, the Natural Resources segment held a 50% interest in a coal services company with Alpha Natural Resources. In December 2014, Regency acquired the remaining 50% membership interest. The company, now known as Materials Handling Solutions, LLC, owns and operates facilities for industrial customers on a fee basis. During 2014, coal reserves located in the San Juan basin depleted and associated coal royalties revenues ceased.

Investment in Lake Charles LNG

Regasification Facility

Lake Charles LNG, a wholly-owned subsidiary of ETE, owns a LNG import terminal and regasification facility located on Louisiana's Gulf Coast near Lake Charles, Louisiana. The import terminal has approximately 9.0 Bcf of above ground LNG storage capacity and the regasification facility has a run rate send out capacity of 1.8 bcf/day.

Liquefaction Project

LCL, an entity owned 60% by ETE and 40% by ETP, is in the process of developing the liquefaction project in conjunction with BG pursuant to a project development agreement entered into in September 2013. Pursuant to this agreement, each of LCL and BG are obligated to pay 50% of the development expenses for the liquefaction project, subject to reimbursement by the other party if such party withdraws from the project prior to both parties making an affirmative FID to become irrevocably obligated to fully develop the project, subject to certain exceptions. The liquefaction project is expected to consist of three LNG trains with a combined design nameplate outlet capacity of 16.2 metric tonnes per annum. Once completed, the liquefaction project will enable LCL to liquefy domestically produced natural gas and export it as LNG. By adding the new liquefaction facility and integrating with the existing LNG regasification/import facility, the enhanced facility will become a bi-directional facility capable of exporting and importing LNG. BG is the sole customer for the existing regasification facility and is obligated to pay reservation fees for 100% of the regasification capacity regardless of whether it actually utilizes such capacity pursuant to a regasification services agreement that terminates in 2030. The liquefaction project will be constructed on 400 acres of land, of which 200 acres are owned or leased by Lake Charles LNG and 200 acres are to be leased by LCL under a long-term lease from the Lake Charles Harbor and Terminal District or purchased by LCL pursuant to the exercise of an option agreement entered into in connection with the liquefaction project.

The construction of the liquefaction project is subject to each of LCL and BG making an affirmative FID to proceed with the project, which decision is in the sole discretion of each party. In the event an affirmative FID is made by both parties, LCL and BG will enter into several agreements related to the project, including a liquefaction services agreement pursuant to which BG will pay LCL for liquefaction services on a tolling basis for a minimum 25-year term with evergreen extension options for 20 years. In addition, a subsidiary of BG, a highly experienced owner and operator of LNG facilities, would oversee construction of the liquefaction facility and, upon completion of construction, manage the operations of the liquefaction facility on behalf of LCL. Subject to receipt of regulatory approvals, we anticipate that each of LCL and BG will make an affirmative FID in 2016 and then commence construction of the liquefaction project in order to place the first LNG train in service in late 2019 and the second and third trains in service during 2020.

The export of LNG produced by the liquefaction project from the U.S. will be undertaken under long-term export authorizations issued by the DOE to Lake Charles Exports, LLC ("LCE"), which is currently a jointly owned subsidiary of BG and ETP and following FID, will be 100% owned by BG. In July 2011, LCE obtained a DOE authorization to export LNG to countries with which the U.S. has or will have Free Trade Agreements ("FTA") for trade in natural gas (the "FTA Authorization"). In August 2013, LCE obtained a conditional DOE authorization to export LNG to countries that do not have an FTA for trade in natural gas (the “Non-FTA Authorization”). The FTA Authorization and Non-FTA Authorization have 25- and 20-year terms, respectively. In January 2013, LCL filed for a secondary, non-cumulative FTA and Non-FTA Authorization to be held by LCL. FTA Authorization was granted in March 2013 and we expect the DOE to issue the Non-FTA Authorization to LCL in due course.

Prior to being authorized to export LNG, we must also receive (i) approvals from the FERC to construct and operate the facilities, (ii) wetlands permits from the U.S. Army Corps of Engineers (“USACE”) to perform wetlands mitigation work and to perform modification and dredging work for the temporary and permanent dock facilities at the Lake Charles LNG facilities, and (iii) air permits from the Louisiana Department of Environmental Quality (“LDEQ”) for emissions from the liquefaction project. We expect to receive the wetlands permit from the USACE and the air permit from the LDEQ in the third quarter of 2015.

In January 2015, LCL received from FERC its notice of schedule. The FERC notice of schedule provides an important timeline for the issuance of the Notice of Availability of Final Environmental Impact Statement (the “FEIS”). The issuance of the FEIS is scheduled for August 14, 2015, which then starts the 90-day period in which other federal agencies are to complete their review of the project and issue any required agency authorizations. The federal decision deadline date is November 12, 2015 and the FERC authorization for the project is anticipated during this 90-day period.

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, including those affiliated with major oil, petrochemical and natural gas companies, and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees, reliability and quality of customer service. We face competition with other storage facilities based on fees charged and the ability to receive and distribute the customer’s products. We compete with a number of NGL fractionators in Texas and Louisiana. Competition for such services is primarily based on the fractionation fee charged.

Crude Oil and Products

In markets served by our products and crude oil pipelines, we face competition with other pipelines. Generally, pipelines are the lowest cost method for long-haul, overland movement of products and crud oil. 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 products 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 products, the high capital costs deter competitors for the crude oil pipeline systems from building new pipelines. Competitive factors in crude oil purchasing and marketing include 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 and Sunoco LP.

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, gas and electric utilities and midstream companies. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that 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.

Natural gas transportation and midstream revenues are derived significantly from companies that engage in exploration and production activities. The discovery and development of new shale formations across the United States has created an abundance of natural gas and crude oil resulting in a negative impact on prices in recent years for natural gas and in recent months for crude oil. 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, 2014, none of our customers individually accounted for more than 10% of our consolidated revenues.

Regulation of Interstate Natural Gas Pipelines. The FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the Natural Gas Act ("NGA"), the FERC generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, "transportation" includes natural gas pipeline transmission (forwardhauls and backhauls), storage and other services. The Florida Gas Transmission, Transwestern, Panhandle Eastern, Trunkline Gas, Tiger, Fayetteville Express and Sea Robin pipelines transport natural gas in interstate commerce and thus each qualifies as a "natural-gas company" under the NGA subject to the FERC's regulatory jurisdiction. We also hold certain storage facilities that are subject to the FERC's regulatory oversight.

The FERC's NGA authority includes the power to regulate:

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

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

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. On October 1, 2014, Transwestern filed a general NGA Section 4 rate case pursuant to the 2011 settlement agreement with its shippers. On December 2, 2014, the FERC issued an order accepting and suspending the rates to be effective April 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in August 2015.

On October 31, 2014, FGT filed a general NGA Section 4 rate case pursuant to a 2010 settlement agreement with its shippers. On November 28, 2014, the FERC issued an order accepting and suspending the rates to be effective May 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in late 2015.

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.

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

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

Regulation of Intrastate Natural Gas and NGL Pipelines. Intrastate transportation of natural gas and NGLs is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce, the rates and terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates and terms and conditions of some transportation and storage services provided on the Oasis pipeline, HPL System, East Texas pipeline and ET Fuel System are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates 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 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 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 Products Pipelines. Some of our crude oil and 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 certain gas 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. Most recently, in an August 2014 U.S. Government Accountability Office (the “GAO”) report to Congress, the GAO acknowledged PHMSA's continued assessment of the safety risks posed by these gathering lines as part of the rulemaking process, and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. 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, the NGPSA and HLPSA 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 Texas Railroad Commission, 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, capital expenditures 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, operating and maintenance 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, the Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("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, as amended, ("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 certain wastes associated with the exploration, development and production of crude oil and natural gas. 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 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, 2014 and 2013, accruals of $401 million and $403 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, for example, certain matters assumed in connection with our acquisition of the HPL System, our acquisition of Transwestern, potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors, and the predecessor owner's share of certain environmental liabilities of ETC OLP.

The Partnership is subject to extensive and frequently changing federal, state and local laws and regulations, including 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 remediation efforts at many of Sunoco, Inc.'s facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $363 million and $377 million at December 31, 2014 and 2013, respectively, 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, Inc., 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, 2014 the captive insurance company held $267 million of cash and investments.

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 non-hazardous 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 or issue is evaluated individually based upon information available for the site or 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 allows 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, 2014, 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, as amended, 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 regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which rulemaking proposed to revise the National Ambient Air Quality Standard ("NAAQS") for ozone between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. EPA also requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. If EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could apply to our operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended, 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 state waters and 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 other products. The Clean Water Act, or amended by the federal Oil Pollution Act of 1990, as amended, ("OPA") 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 OPA 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 PHMSA, 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. Based on findings made by the EPA that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD") and Title V permitting reviews for greenhouse gas emission from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant 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 typically developed by the states. 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 adopted regulations requiring the annual reporting of greenhouse gas emissions from certain petroleum and natural gas sources in the United States, including onshore oil and natural gas production, processing, transmission, storage and distribution facilities. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual greenhouse gas emissions reporting is currently required to include greenhouse gas emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. We are monitoring greenhouse gas emissions from certain of our facilities in accordance with current greenhouse emissions reporting requirements in a manner that we believe is in substantial compliance with applicable reporting obligations and are currently assessing the potential impact that the December 9, 2014 proposed rule may have on our future reporting obligations, should the proposal be adopted.

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. For example, in January 2015, the Obama Administration announced plans for the EPA to issue final standards in 2016 that would reduce methane emissions from new and modified oil and natural gas production and natural gas processing and transmission facilities by up to 45% from 2012 levels by 2025.

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 30, 2015, ETE and its consolidated subsidiaries employed an aggregate of 27,605 employees, 1,609 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 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.

SELECTED FINANCIAL DATA

The selected historical financial data should be read in conjunction with "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.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
Statement of Operations Data:					
Total revenues	$ 55,691	$ 48,335	$ 16,964	$ 8,190	$ 6,556
Operating income	2,470	1,551	1,360	1,237	1,044
Income from continuing operations	1,060	282	1,383	531	345
Basic income from continuing operations per limited partner unit	0.58	0.17	0.29	0.35	0.22
Diluted income from continuing operations per limited partner unit	0.57	0.17	0.29	0.35	0.22
Cash distribution per unit	0.80	0.67	0.63	0.61	0.54
Balance Sheet Data (at period end):					
Total assets	64,469	50,330	48,904	20,897	17,379
Long-term debt, less current maturities	29,653	22,562	21,440	10,947	9,346
Total equity	22,314	16,279	16,350	7,388	6,248

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, Inc., Sunoco Logistics, Sunoco LP, Susser and ETP Holdco. References to the "Parent Company" mean Energy Transfer Equity, L.P. on a stand-alone basis.

In 2014, our consolidated subsidiaries, Trunkline LNG Company, LLC, Trunkline LNG Export, LLC and Susser Petroleum Partners LP, changed their names to Lake Charles LNG Company, LLC, Lake Charles LNG Export, LLC and Sunoco LP, respectively. All references to these subsidiaries throughout this document reflect the new names of those subsidiaries, regardless of whether the disclosure relates to periods or events prior to the dates of the name changes.

All information in this document is reported as of March 2, 2015, the date the Partnership's Form 10-K for the year ended December 31, 2014 was originally filed, except for (i) information where the context specifically states otherwise (e.g., fiscal year end information reported as of December 31, 2014), (ii) information related to the Regency Merger and the resulting segment change, and (iii) unit or per-unit amounts that have been adjusted for the July 2015 unit split.

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, 2014, 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	30.8	57.2
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, and the Partnership's ownership of Lake Charles LNG. 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 liquids 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.

Subsequent to ETP's acquisition of Regency, our financial statements reflect the following reportable business segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Lake Charles LNG, including the operations of Lake Charles LNG; 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.

ETP completed its acquisition of Regency in April 2015; therefore, the Investment in ETP segment amounts have been retrospectively adjusted to reflect Regency for the periods presented.

The general partner of ETP has separate operating management and board of directors. We control ETP through our ownership of its general partner.

Recent Developments

Regency Merger

In April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the "Regency Merger"). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new ETP Series A Preferred Units.

In connection with the transaction, ETE, which owns the general partner and 100% of the incentive distribution rights of ETP, will reduce the incentive distributions it receives from ETP by a total of $320 million over a five-year period. The IDR subsidy will be $80 million in the first year post-closing and $60 million per year for the following four years.

Bakken Pipeline Transaction

In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE's 45% interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline (collectively, the "Bakken pipeline project"), and $879 million in cash (less amounts funded prior to closing by ETE for capital expenditures for the Bakken pipeline project) in exchange for 30.8 million newly issued ETP Class H Units that, when combined with the 50.2 million previously issued ETP Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics. In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016.

Acquisition of West Texas Gulf by Sunoco Logistics

In December 2014, Sunoco Logistics acquired an additional 28.3% ownership interest in the West Texas Gulf Pipe Line Company from Chevron Pipe Line Company, increasing its controlling financial interest in the consolidated subsidiary to 88.6%. The remaining 11.4% was acquired from Southwest Pipeline Holding Company, LLC in January 2015.

Lone Star NGL Pipeline and Conversion Project

In November 2014, ETP and Regency announced that Lone Star will construct a 533 mile, 24- and 30-inch NGL pipeline from the Permian Basin to Mont Belvieu, Texas and convert Lone Star's existing West Texas 12-inch NGL pipeline into crude oil/condensate service. The new pipeline and conversion projects, estimated to cost between $1.5 billion and $1.8 billion, are expected to be operational by the third quarter of 2016 and the first quarter of 2017, respectively.

Gathering and Processing Construction Projects

In November 2014, ETP announced its plans to construct two new 200 million cubic feet per day cryogenic gas processing plants and associated gathering systems in the Eagle Ford and Eaglebine production areas. ETP expects to have the first plant online by June 2015 and the second plant by the fourth quarter of 2015.

Lone Star Fractionator

In November 2014, ETP and Regency announced that Lone Star will construct a third natural gas liquids fractionator at its facility in Mont Belvieu, Texas, which will bring Lone Star's total fractionation capacity at Mont Belvieu to 300,000 Bbls/d. Lone Star's third fractionator is scheduled to be operational by December 2015.

Phillips 66 Joint Ventures

In October 2014, ETE, ETP and Phillips 66 formed two joint ventures to develop the previously announced Dakota Access Pipeline ("DAPL") and Energy Transfer Crude Oil Pipeline ("ETCOP") projects. ETP and ETE hold an aggregate interest of 75% in each joint venture and ETP operates both pipeline systems. Phillips 66 owns the remaining 25% interests and funds its proportionate share of the construction costs. The DAPL and ETCOP projects are expected to begin commercial operations in the fourth quarter of 2016.

ET Rover

In June 2014, ETP announced a natural gas pipeline project (now called "Rover") to connect Marcellus and Utica shale supplies to markets in the Midwest, Great Lakes, and Gulf Coast regions of the United States and Canada. ETP has secured multiple, long-term binding shipper agreements on Rover. As a result of these binding agreements, the pipeline is substantially subscribed with 15- and 20-year fee-based contracts to transport up to 3.25 Bcf/d of capacity. Also, ETP recently announced that AE–Midco Rover, LLC ("AE–Midco"), has exercised its option to increase its equity ownership interest in Rover. As a result, AE–Midco (and an affiliate of AE–Midco) will own 35% of Rover and ETP will own 65%.

MACS to Sunoco LP

In October 2014, Sunoco LP acquired MACS from a subsidiary of ETP in a transaction valued at approximately $768 million (the "MACS Transaction"). The transaction included approximately 110 company-operated retail convenience stores and 200 dealer-operated and consignment sites from MACS, which had originally been acquired by ETP in October 2013. The consideration paid by Sunoco LP consisted of approximately 4 million Sunoco LP common units issued to ETP and $556 million in cash, subject to customary closing adjustments. Sunoco LP initially financed the cash portion by utilizing availability under its revolving credit facility. In October 2014 and November 2014, Sunoco LP partially repaid borrowings on its revolving credit facility with aggregate net proceeds of $405 million from a public offering of 9.1 million Sunoco LP common units.

ETE Unit Repurchase

From January through May 2014, ETE repurchased approximately $1 billion of ETE common units under its buyback program.

Lake Charles LNG Transaction

In February 2014, ETP completed the transfer to ETE of Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, 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 connection with ETE's acquisition of Lake Charles LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles 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 9 to our consolidated financial statements.

Results of Operations

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, depletions, 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.

Based on the change in our reportable segments, we have adjusted the presentation of our segment results for the prior years to be consistent with the current year presentation.

Eliminations in the tables below include the following:

- ETP's Segment Adjusted EBITDA reflected the results of Lake Charles LNG prior to the Lake Charles LNG Transaction, which was effective January 1, 2014. The Investment in Lake Charles LNG segment reflected the results of operations of Lake Charles LNG for all periods presented. Consequently, the results of operations of Lake Charles LNG were reflected in two segments for the year ended December 31, 2013 and the period from March 26, 2012 to December 31, 2012. Therefore, the results of Lake Charles LNG were included in eliminations for 2013 and 2012.

Consolidated Results

	Years Ended December 31, 2014	Years Ended December 31, 2013	Change
Segment Adjusted EBITDA:			
Investment in ETP	$ 5,710	$ 4,404	$ 1,306
Investment in Lake Charles LNG	195	187	8
Corporate and Other	(97)	(43)	(54)
Adjustments and eliminations	32	(181)	213
Total	5,840	4,367	1,473
Depreciation, depletion and amortization	(1,724)	(1,313)	(411)
Interest expense, net of interest capitalized	(1,369)	(1,221)	(148)
Gain on sale of AmeriGas common units	177	87	90
Goodwill impairments	(370)	(689)	319
Gains (losses) on interest rate derivatives	(157)	53	(210)
Non-cash unit-based compensation expense	(82)	(61)	(21)
Unrealized gains on commodity risk management activities	116	48	68
Inventory valuation adjustments	(473)	3	(476)
Losses on extinguishments of debt	(25)	(162)	137
Adjusted EBITDA related to discontinued operations	(27)	(76)	49
Adjusted EBITDA related to unconsolidated affiliates	(748)	(727)	(21)
Equity in earnings of unconsolidated affiliates	332	236	96
Non-operating environmental remediation	—	(168)	168
Other, net	(73)	(2)	(71)
Income from continuing operations before income tax expense	1,417	375	1,042
Income tax expense	357	93	264
Income from continuing operations	1,060	282	778
Income from discontinued operations	64	33	31
Net income	$ 1,124	$ 315	$ 809

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

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased primarily as a result of acquisitions and growth projects, including an increase of $254 million at Regency primarily due to depreciation, depletion and amortization related to the PVR, Eagle Rock and Hoover acquisitions, as well as additional depreciation, depletion and amortization recorded from assets placed in service in 2014 and 2013.

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

- an increase of $140 million related to Regency primarily due to its issuance of $600 million of senior notes in April 2013, $400 million of senior notes in September 2013, $900 of million senior notes in February 2014 and $700 of million senior notes issued in July 2014, as well as the assumption of $1.2 billion of senior notes in the PVR Acquistion and the exchange of $499 million of senior notes in the Eagle Rock Acquisition; and

- an increase of $11 million related to ETP primarily 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; partially offset by

- a reduction of $5 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, net of interest related to incremental debt.

Gain on Sale of AmeriGas Common Units. During the year ended December 31, 2014 and 2013, ETP sold 18.9 million and 7.5 million, respectively, of the AmeriGas common units that were 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. As of December 31, 2014, ETP’s remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

Goodwill Impairments. In 2013, Lake Charles 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 Lake Charles 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 Lake Charles LNG reporting unit was less than its carrying amount.

During the fourth quarter of 2014, a $370 million goodwill impairment was recorded related to Regency’s Permian Basin gathering and processing operations. The decline in estimated fair value of that reporting unit was primarily driven by the significant decline in commodity prices in the fourth quarter of 2014, and the resulting impact to future commodity prices as well as increases in future estimated operations and maintenance expenses. An assessment of these factors in the fourth quarter of 2014 led to a conclusion that the estimated fair value of Regency’s Permian reporting unit was less than its carrying amount.

Gains (Losses) on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Losses on interest rate derivatives during the year ended December 31, 2014 resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value. Conversely, increases in forward interest rates resulted in gains on interest rate derivatives during the year ended December 31, 2013.

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.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco Logistics’ crude oil and products inventories and ETP’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, losses on extinguishment of debt were primarily related to ETE’s refinancing transactions completed in December 2013. In addition, the years ended December 31, 2014 and 2013 also reflected losses of $25 million and $7 million, respectively, related to Regency’s repurchase of its senior notes during the respective periods.

Adjusted EBITDA Related to Discontinued Operations. In 2014, amounts were related to a marketing business that was sold effective April 1, 2014. In 2013, amounts primarily related to Southern Union’s local distribution operations.

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 our equity method investees. See additional discussion of results in “Segment Operating Results” below.

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

Other, net. Includes amortization of regulatory assets, certain acquisition related costs and other income and expense amounts.

Income Tax Expense from Continuing Operations. Income tax expense is based on the earnings of our taxable subsidiaries. In addition, the year ended December 31, 2014 included the impact of the Lake Charles LNG Transaction, which was treated as a sale for tax purposes, resulting in $76 million of incremental income tax expense.

Segment Operating Results

Investment in ETP

	Years Ended December 31,		
	2014	2013	Change
Revenues	$ 55,475	$ 48,335	$ 7,140
Cost of products sold	48,389	42,554	5,835
Gross margin	7,086	5,781	1,305
Unrealized gains on commodity risk management activities	(112)	(42)	(70)
Operating expenses, excluding non-cash compensation expense	(2,090)	(1,683)	(407)
Selling, general and administrative expenses, excluding non-cash compensation expense	(508)	(439)	(69)
Inventory valuation adjustments	473	(3)	476
Adjusted EBITDA related to discontinued operations	27	76	(49)
Adjusted EBITDA related to unconsolidated affiliates	748	722	26
Other, net	86	(8)	94
Segment Adjusted EBITDA	$ 5,710	$ 4,404	$ 1,306

Gross Margin. For the year ended December 31, 2014 compared to the prior year, ETP's gross margin increased primarily as a result of the following:

- Gross margin included in ETP's consolidated results related to ETP's retail marketing operations increased $471 million between periods due to the acquisition of Susser and MACS as well as favorable fuel margins.
- Gross margin related to ETP's liquids transportation and services operations increased $273 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 2013.
- Gross margin from ETP's midstream operations increased $784 million primarily due to an increase of $669 million related to Regency's gathering and processing operations, primarily due to Regency's acquisitions of PVR, Eagle Rock midstream assets and Hoover in 2014, and an increase in fee-based revenues of $121 million from ETP's legacy midstream assets due to increased production and increased capacity from assets recently placed in service in the Eagle Ford Shale.
- Gross margin increased $50 million related to Regency's contract service operations due to increased revenue generating horsepower and $58 million related to Regency's natural resources operations due to the acquisition of those assets in March 2014.

These increases were partially offset by the following:

- Revenue from ETP's interstate transportation and storage operations decreased $237 million primarily as a result of the deconsolidated of Lake Charles LNG and the recognition in 2013 of $52 million received in connection with the buyout of a customer contract.
- Gross margin related to ETP's intrastate transportation and storage operations decreased $27 million primarily due to the cessation of long-term transportation contracts.
- Sunoco Logistics' gross margin decreased $87 million primarily related to lower crude oil margins.

Unrealized Gains on Commodity Risk Management Activities. Unrealized gains 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 gains on commodity risk management activities for 2014 compared to 2013 was primarily attributable to natural gas storage inventory and related derivatives.

Operating Expenses, Excluding Non-Cash Compensation Expense. Operating expenses related to ETP's retail marketing operations increased $254 million, primarily due to recent acquisitions. In addition, Sunoco Logistics' operating expenses increased $44 million, primarily due to lower pipeline operating gains, increased pipeline maintenance costs and higher employee costs. Operating expenses related to ETP's midstream operations increased $123 million primarily due to a $76 million increase in pipeline and plant maintenance and materials due to organic growth on Regency's assets in south and west Texas, as well as Regency's acquisitions of PVR, Eagle Rock midstream assets and Hoover in 2014. Operating expenses also increased $18 million for ETP's liquids transportation and services operations, primarily due to the start-up of Lone Star's second fractionator in Mont Belvieu, Texas in October 2013. These increases were partially offset by decreases in ETP's operating expenses due to its deconsolidation of certain operations during the periods, including Lake Charles LNG effective January 1, 2014 and SUGS in April 2013.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Selling, general and administrative expenses related to ETP's retail marketing operations increased $29 million, primarily due to recent acquisitions. In addition, Sunoco Logistics' selling, general and administrative expenses increased $28 million. Selling, general and administrative expenses also increased for ETP's liquids transportation and services operations due to higher employee-related costs. These increases were partially offset by decreases in ETP's expenses due to its deconsolidation of Lake Charles LNG effective January 1, 2014.

Adjusted EBITDA Related to Discontinued Operations. In 2014, amounts were related to a marketing business that was sold effective April 1, 2014. In 2013, amounts primarily related to 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, 2014 and 2013 consisted of the following:

	Years Ended December 31,		
	2014	2013	Change
Citrus	$ 305	$ 296	$ 9
FEP	75	75	—
PES	86	(30)	116
MEP	102	100	2
HPC	53	51	2
AmeriGas	56	175	(119)
Other	71	55	16
Total Adjusted EBITDA related to unconsolidated affiliates	$ 748	$ 722	$ 26

These amounts represent ETP's proportionate share of the Adjusted EBITDA of its unconsolidated affiliates and are based on ETP's equity in earnings or losses of its unconsolidated affiliates adjusted for its proportionate share of the unconsolidated affiliates' interest, depreciation, amortization, non-cash items and taxes.

Other. Other, net in 2014 primarily includes amortization of regulatory assets and other income and expense amounts. Other, net in 2013 was primarily related to biodiesel tax credits recorded by Sunoco, Inc., amortization of regulatory assets and other income and expense amounts.

Investment in Lake Charles LNG

	Years Ended December 31,		
	2014	2013	Change
Revenues	$ 216	$ 216	$ —
Operating expenses, excluding non-cash compensation expense	(17)	(20)	3
Selling, general and administrative, excluding non-cash compensation expense	(4)	(9)	5
Segment Adjusted EBITDA	$ 195	$ 187	$ 8

Amounts reflected above include comparative amounts for the year ended December 31, 2013, which preceded ETE's direct investment in Lake Charles LNG effective January 1, 2014.

Lake Charles LNG derives all of its revenue from a contract with a non-affiliated gas marketer.

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012 (tabular dollar amounts are expressed in millions)

Consolidated Results

	Years Ended December 31,		
	2013	2012	Change
Segment Adjusted EBITDA:			
Investment in ETP	$ 4,404	$ 3,139	$ 1,265
Investment in Lake Charles LNG	187	135	52
Corporate and Other	(43)	(52)	9
Adjustments and Eliminations	(181)	(117)	(64)
Total	4,367	3,105	1,262
Depreciation, depletion 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 non-hedged 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
Inventory 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, Depletion and Amortization. Depreciation, depletion 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, Inc. 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, depletion 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, Inc. 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, Lake Charles LNG recorded a $689 million goodwill impairment. See additional discussion in the analysis of consolidated results for the year ended December 31, 2014 compared to the year ended December 31, 2013.

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.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with ETP'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, Inc.'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 from Continuing Operations. Income tax expense increased primarily due to the acquisitions of Southern Union and Sunoco, Inc. in 2012, both of which are taxable corporations.

Segment Operating Results

Investment in ETP

	Years Ended December 31,		
	2013	2012	Change
Revenues	$ 48,335	$ 16,964	$ 31,371
Cost of products sold	42,554	13,088	29,466
Gross margin	5,781	3,876	1,905
Unrealized (gains) losses on commodity risk management activities	(42)	(2)	(40)
Operating expenses, excluding non-cash compensation expense	(1,683)	(1,117)	(566)
Selling, general and administrative, excluding non-cash compensation expense	(439)	(438)	(1)
Inventory valuation adjustments	(3)	75	(78)
Adjusted EBITDA related to discontinued operations	76	99	(23)
Adjusted EBITDA related to unconsolidated affiliates	722	646	76
Other, net	(8)	—	(8)
Segment Adjusted EBITDA	$ 4,404	$ 3,139	$ 1,265

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 and the recognition of $52 million received in connection with the buyout of a Southern Union customer's contract.

- Gross margin related to ETP's liquids 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.

- Gross margin related to ETP's midstream operations increased $189 million compared to the prior year. With respect to ETP's legacy assets, gross margin increased due to a $125 million increase in fee-based revenues resulting from increased volumes from production in the Eagle Ford Shale, offset by a $27 million decrease in non fee-based margins due to lower NGL prices on our Southeast Texas system. Gross margin from Regency's gathering and processing assets increased $97 million primarily due to volume growth in south and west Texas and north Louisiana and a full year of contribution from the SUGS assets versus nine months contribution in 2012.

- 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.

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 $90 million and $343 million, respectively, between periods. In addition, ETP's interstate transportation and storage's operating expenses increased $76 million primarily as a result of ETP's consolidation of Southern Union. Operating expenses for ETP's liquids transportation and services operations increased approximately $47 million primarily due to additional expenses from assets being placed in service. Operating expenses related to ETP's marketing operations increased $86 million due to a full year of activity from the SUGS assets in 2013 versus nine months in 2012, as well as additional expenses from assets recently placed in service, particularly from organic growth in Regency's south and west Texas assets. 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 reflected 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 $57 million and $57 million, respectively, between periods. These increases were partially offset by decreases in ETP's interstate transportation and storage operations and midstream operations of $63 million and $40 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)
MEP	100	102	(2)
HPC	51	65	(14)
PES	(30)	26	(56)
Other	55	9	46
Total Adjusted EBITDA related to unconsolidated affiliates	$ 722	$ 646	$ 76

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

Other. Other amounts in 2013 were primarily related to Sunoco, Inc.'s recognition of environmental obligations related to closed sites.

Investment in Lake Charles LNG

	Years Ended December 31,		
	2013	2012	Change
Revenues	$ 216	$ 166	$ 50
Operating expenses, excluding non-cash compensation expense	(20)	(12)	(8)
Selling, general and administrative, excluding non-cash compensation expense	(9)	(19)	10
Segment Adjusted EBITDA	$ 187	$ 135	$ 52

Amounts reflected above include the results of Lake Charles LNG beginning March 26, 2012, the date which ETE obtained control of Trunkline LNG through the acquistion of Southern Union.

Lake Charles LNG derives all of its revenue from a contract with a non-affiliated gas marketer.

Operating Expenses, Excluding Non-Cash Compensation Expense. For the year ended December 31, 2013 compared to the prior year, Lake Charles LNG's operating expense increased primarily as a result of a full year of operations which were consolidated beginning on March 26, 2012.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. The decrease in expenses compared to the prior year was primarily a result of $9 million of merger-related expenses recorded in 2012.

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 ETP Holdco Transaction for the years ended December 31, 2012, giving effect that each occurred on January 1, 2012. 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 ETP Holdco Transaction had been consummated on January 1, 2012.

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

	ETE Historical	Propane Transaction[(a)]	Sunoco, Inc. Historical[(b)]	Southern Union Historical[(c)]	ETP 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, depletion 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

(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, Inc. 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 ETP Holdco pro forma adjustments relate to Sunoco, Inc.'s exit from its Northeast refining operations and formation of the PES joint venture, except for the following:

- The adjustment to depreciation, depletion 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 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, Inc. and Southern Union.

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 cash flows from the operations of Lake Charles LNG. The amount of cash that ETP distributes to its partners, including the Parent Company, each quarter is based on earnings from its business activities and the amount of available cash, as discussed below. In connection with previous transactions, we have relinquished a portion of our incentive distributions to be received from ETP, 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. 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 and Lake Charles LNG. The Parent Company distributes its available cash remaining after satisfaction of the aforementioned cash requirements to its Unitholders on a quarterly basis.

We expect our 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 (net of contributions in aid of construction costs) in 2015 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Direct[1]:				
Intrastate transportation and storage	$ 130	$ 180	$ 30	$ 35
Interstate transportation and storage[2]	700	750	130	140
Midstream	1,900	2,000	90	110
Liquids transportation and services:				
NGL	1,550	1,600	20	25
Crude[2]	800	850	—	—
Retail marketing[3]	160	210	55	75
All other (including eliminations)	200	250	35	45
Total direct capital expenditures	5,440	5,840	360	430
Indirect[1]:				
Investment in Sunoco Logistics	2,400	2,600	65	75
Investment in Sunoco LP[3]	220	270	40	50
Total indirect capital expenditures	2,620	2,870	105	125
Total projected capital expenditures	$ 8,060	$ 8,710	$ 465	$ 555

(1) Indirect capital expenditures comprise those funded by ETP’s publicly traded subsidiaries; all other capital expenditures are reflected as direct capital expenditures.

(2) Includes capital expenditures related to our proportionate ownership of the Bakken and Rover pipeline projects.

(3) ETP’s retail marketing operations include the investment in Sunoco LP, as well as ETP’s wholly-owned retail marketing operations. Capital expenditures by Sunoco LP are reflected as indirect because Sunoco LP is a publicly traded subsidiary.

The assets used in ETP’s natural gas and liquids 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, 2014, in addition to $663 million of cash on hand, ETP had available capacity under its revolving credit facilities of $1.81 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 through the end of 2015; 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, 2014, Sunoco Logistics had available borrowing capacity of $1.35 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.

Sunoco LP's primary sources of liquidity consist of cash generated from operating activities and borrowings under its $1.25 billion credit facility. At December 31, 2014, Sunoco LP had available borrowing capacity of $567 million under its revolving credit facility.

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, depletion and amortization expense and non-cash compensation expense. The increase in depreciation, depletion 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, 2014

Cash provided by operating activities in 2014 was $3.18 billion and net income was $1.12 billion. The difference between net income and cash provided by operating activities in 2014 consisted of net non-cash items totaling $1.99 billion and changes in operating assets and liabilities of $231 million. The non-cash activity in 2014 consisted primarily of depreciation, depletion and amortization of $1.72 billion, goodwill impairment of $370 million, inventory valuation adjustments of $473 million, losses on extinguishments of debt of $25 million and non-cash compensation expense of $82 million, partially offset by the gain on the sale of AmeriGas common units of $177 million and a deferred income tax benefit of $50 million.

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, depletion 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, depletion and amortization of $871 million, losses on extinguishments of debt of $123 million and non-cash compensation expense of $47 million.

Investing Activities

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

Following is a summary of investing activities by period:

Year Ended December 31, 2014

Cash used in investing activities in 2014 of $6.80 billion was comprised primarily of capital expenditures of $5.34 billion (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs). ETP invested $5.05 billion for growth capital expenditures and $444 million for maintenance capital expenditures during 2014. Regency invested $1.20 billion for growth capital expenditures and $98 million for maintenance capital expenditures during 2014. We paid cash for acquisitions of $2.37 billion and received $814 million in cash received from the sale of AmeriGas common units.

Year Ended December 31, 2013

Cash used in investing activities in 2013 of $2.35 billion was comprised primarily of capital expenditures of $3.45 billion (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs). 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 $3.24 billion (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs). 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.

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, 2014

Cash provided by financing activities was $3.88 billion in 2014. We had a consolidated increase in our debt level of $4.49 billion, primarily due to Regency's issuance of senior notes and assumption and debt, and Sunoco Logistics' issuance of $2.00 billion in aggregate principal amount of senior notes in April 2014 and November 2014 (see Note 6 to our consolidated financial statements) and an increase of the Parent Company's debt of $1.88 billion. Our subsidiaries also received $3.06 billion in proceeds from common unit offerings, including $1.38 billion from the issuance of ETP Common Units, $428 million from the issuance of Regency Common Units and $1.25 billion from the issuance of other subsidiary common units. We paid distributions to partners of $821 million, and our subsidiaries paid $1.91 billion on limited partner interests other than those held by the Parent Company. We also paid $1.00 billion to repurchase common units during the year ended December 31, 2014.

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, Inc. 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.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31,	
	2014	2013
Parent Company Indebtedness:		
ETE Senior Notes due October 15, 2020	$ 1,187	$ 1,187
ETE Senior Notes due January 15, 2024	1,150	450
ETE Senior Secured Term Loan, due December 2, 2019	1,400	1,000
ETE Senior Secured Revolving Credit Facility due December 2, 2018	940	171
Subsidiary Indebtedness:		
ETP Senior Notes	10,890	11,182
Panhandle Senior Notes	1,085	1,085
PVR Senior Notes	790	—
Regency Senior Notes	4,299	2,800
Sunoco, Inc. Senior Notes	715	965
Sunoco Logistics Senior Notes	3,975	2,150
Transwestern Senior Notes	782	870
Revolving Credit Facilities:		
ETP $2.5 billion Revolving Credit Facility due October 27, 2019	570	65
Regency $2 billion Revolving Credit Facility due November 25, 2019	1,504	510
Sunoco Logistics' subsidiary $35 million Revolving Credit Facility due April 30, 2015	35	35
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 19, 2018	150	200
Sunoco LP $1.25 billion Revolving Credit Facility due September 25, 2019	683	—
Other Long-Term Debt	223	228
Unamortized premiums and fair value adjustments, net	283	301
Total debt	30,661	23,199
Less: current maturities of long-term debt	1,008	637
Long-term debt, less current maturities	$ 29,653	$ 22,562

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

ETE Term Loan Facility

The Parent Company has 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%.

In April 2014, the Parent Company amended the ETE Term Credit Agreement to increase the aggregate principal amount to $1.4 billion. The Parent Company used the proceeds from this $400 million increase to repay borrowings under its revolving credit facility and for general partnership purposes. No other significant changes were made to the terms of the ETE Term Credit Agreement, including maturity date and interest rate.

ETE Revolving Credit Facility

The Parent Company has 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. In May 2014, the Parent Company amended its revolving credit facility to increase the capacity to $1.2 billion. In February 2015, the Parent Company amended its revolving credit facility to increase the capacity to $1.5 billion.

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

Sunoco Logistics Senior Notes Offerings

In April 2014, Sunoco Logistics issued $300 million aggregate principal amount of 4.25% senior notes due April 2024 and $700 million aggregate principal amount of 5.30% senior notes due April 2044. In November 2014, Sunoco Logistics issued an additional $200 million under the April 2024 senior notes and $800 million aggregate principal amount of 5.35% senior notes due May 2045. Sunoco Logistics' used the net proceeds from the offering to pay borrowings under the Sunoco Logistics Credit Facility and for general partnership purposes.

Credit Facilities

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $2.5 billion and expires in October 2019. 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. In February 2015, ETP amended its revolving credit facility to increase the capacity to $3.75 billion.

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.

As of December 31, 2014, the ETP Credit Facility had $570 million outstanding, and the amount available for future borrowings was $1.81 billion taking into account letters of credit of $121 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 was 1.66%.

Regency Revolving Credit Facility

The Regency Credit Facility has aggregate revolving commitments of $2.0 billion, with a $500 million incremental facility. The maturity date of the Regency Credit Facility is November 25, 2019.

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. The Regency Credit Facility allows for investments in its joint ventures.

As of December 31, 2014, Regency had a balance outstanding of $1.50 billion under the Regency Credit Facility in revolving credit loans and approximately $23 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2014, which is reduced by any letters of credit, was approximately $473 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 was 2.17%.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $1.50 billion unsecured credit facility (the "Sunoco Logistics Credit Facility") which matures in November 2018. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions.

The Sunoco Logistics Credit Facility is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The Sunoco Logistics Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. As of December 31, 2014, the Sunoco Logistics Credit Facility had $150 million of outstanding borrowings.

West Texas Gulf Pipe Line Company, a subsidiary of Sunoco Logistics, maintains 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. At December 31, 2014, this credit facility had $35 million of outstanding borrowings.

Sunoco LP Credit Facility

In September 2014, Sunoco LP entered into a $1.25 billion revolving credit agreement (the "Sunoco LP Credit Facility"), which expires in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP's written request, subject to certain conditions, up to an additional $250 million. As of December 31, 2014, the Sunoco LP Credit Facility had $683 million of outstanding borrowings.

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) 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

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 these covenants except that the liens covenant will continue to be applicable. ETP has advised Regency that it intends to provide an ETP guarantee with respect to the outstanding Regency senior notes upon the closing of the Regency merger, and it is expected that this will result in the Regency senior notes being upgrade an investment grade rating by both Moody's and S&P.

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 Panhandle

Panhandle 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 Panhandle’s lending agreements. Financial covenants exist in certain of Panhandle’s debt agreements that require Panhandle 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 Panhandle 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 Panhandle did not cure such default within any permitted cure period or if Panhandle did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Panhandle’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 Panhandle’s debt and other financial obligations and that of its subsidiaries.

In addition, Panhandle 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 Panhandle’s cash management program; and limitations on Panhandle’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 3.7 to 1 at December 31, 2014, as calculated in accordance with the credit agreements.

The West Texas Gulf Pipeline Company’s $35 million credit facility limits West Texas Gulf, on a rolling four-quarter basis, to a minimum fixed charge coverage ratio of 1.00 to 1. 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 1.67 to 1 and 0.85 to 1, respectively, at December 31, 2014.

Covenants Related to Sunoco LP

The Sunoco LP Credit Facility requires Sunoco LP to maintain a leverage ratio of not more than 5.50 to 1. The maximum leverage ratio is subject to upwards adjustment of not more than 6.00 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in an acquisition of assets, equity interests, operating lines or divisions by Sunoco LP, a subsidiary, an unrestricted subsidiary or a joint venture for a purchase price of not less than $50 million. Indebtedness under the Sunoco LP Credit Facility is secured by a security interest in, among other things, all of the Sunoco LP's present and future personal property and all of the present and future personal property of its guarantors, the capital stock of its material subsidiaries (or 66% of the capital stock of material foreign subsidiaries), and any intercompany debt. Upon the first achievement by Sunoco LP of an investment grade credit rating, all security interests securing the Sunoco LP Credit Facility will be released.

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, 2014.

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."

Off-Balance Sheet Arrangements

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, 2014:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 30,378	$ 1,050	$ 1,542	$ 7,757	$ 20,029
Interest on long-term debt[(1)]	17,057	1,565	3,008	2,696	9,788
Payments on derivatives	159	20	83	50	6
Purchase commitments[(2)]	14,177	8,362	3,168	1,188	1,459
Transportation, natural gas storage and fractionation contracts	89	26	43	20	—
Operating lease obligations	1,437	151	247	210	829
Distributions and redemption of preferred units of a subsidiary[(3)]	96	3	7	7	79
Other[(4)]	347	177	77	57	36
Total[(5)]	$ 63,740	$ 11,354	$ 8,175	$ 11,985	$ 32,226

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2014. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2014. 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, 2014 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 $1.12 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) Expected contributions to fund our pension and postretirement benefit plans were included in “Other” above. Environmental liabilities, asset retirement obligations, unrecognized tax benefits, contingency accruals and deferred revenue, which were included in “Other non-current liabilities” our consolidated balance sheets were excluded from the table above as such amounts do not represent contractual obligations or, in some cases, the amount and/or timing of the cash payments is uncertain.

(5) Excludes net non-current deferred tax liabilities of $4.33 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 declared during the periods presented are as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2011	February 7, 2012	February 17, 2012	$ 0.1563
March 31, 2012	May 4, 2012	May 18, 2012	0.1563
June 30, 2012	August 6, 2012	August 17, 2012	0.1563
September 30, 2012	November 6, 2012	November 16, 2012	0.1563
December 31, 2012	February 7, 2013	February 19, 2013	0.1588
March 31, 2013	May 6, 2013	May 17, 2013	0.1613
June 30, 2013	August 5, 2013	August 19, 2013	0.1638
September 30, 2013	November 4, 2013	November 19, 2013	0.1681
December 31, 2013	February 7, 2014	February 19, 2014	0.1731
March 31, 2014	May 5, 2014	May 19, 2014	0.1794
June 30, 2014	August 4, 2014	August 19, 2014	0.1900
September 30, 2014	November 3, 2014	November 19, 2014	0.2075
December 31, 2014	February 6, 2015	February 19, 2015	0.2250

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,		
	2014	2013	2012
Limited Partners	$ 866	$ 748	$ 703
General Partner interest	2	2	1
Class D units	2	—	—
Total Parent Company distributions	$ 870	$ 750	$ 704

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. Lake Charles LNG's wholly-owned subsidiaries also contribute to the Parent Company's cash available for distributions. At December 31, 2014, 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	30.8	57.2
ETP Class H units	50.2	—
Units held by less than wholly-owned subsidiaries:		
Common units	—	31.4
Regency Class F units	—	6.3

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 and its wholly-owned subsidiaries 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,		
	2014	2013	2012
Distributions from ETP:			
Limited Partners	$ 119	$ 268	$ 180
Class H Units held by ETE Holdings	219	105	—
General Partner interest	21	20	20
Incentive distributions	754	701	529
IDR relinquishments related to previous transactions	(250)	(199)	(90)
Total distributions from ETP	863	895	639
Distributions from Regency:			
Limited Partners	99	48	48
General Partner interest	6	5	5
Incentive distributions	33	12	8
IDR relinquishments related to previous transaction	(3)	(3)	—
Total distributions from Regency	135	62	61
Total distributions received from subsidiaries	$ 998	$ 957	$ 700

In connection with transactions between ETP and ETE, ETE has agreed to relinquish its right to certain incentive distributions in future periods. Following is a summary of the net reduction in total distributions that would potentially be made to ETE in future periods based on (i) the currently effective partnership agreement provisions, (ii) the assumed closing of the issuance of additional ETP Class H Units and ETP Class I Units, which is expected to occur in March 2015, and (iii) the assumed closing of the Regency Merger, which is expected to occur in the second quarter of 2015:

Years Ending December 31,	Currently Effective	Pro Forma for ETP Class H and Class I Units(1)	Pro Forma for Regency Merger(2)
2015	$ 86	$ 31	$ 91
2016	107	77	142
2017	85	85	145
2018	80	80	140
2019	70	70	130
2020	35	35	50
2021	35	35	35
2022	35	35	35
2023	35	35	35
2024	18	18	18

(1) Pro forma amounts reflect the IDR subsidies, as adjusted for the pending issuance of additional ETP Class H Units and ETP Class I Units discussed above, as well as distributions on the ETP Class I Units. The issuance of additional ETP Class H Units and ETP Class I Units is expected to close in March 2015.

(2) Pro forma amounts reflect the IDR subsidies, as adjusted for (i) the pending issuance of additional ETP Class H Units and ETP Class I Units (as described in Note (1) above) and (ii) the pending Regency Merger. Amounts reflected above assume that the Regency Merger is closed subsequent to the record date for the first quarter of 2015 distribution payment and prior to the record date for the second quarter 2015 distribution payment.

The amounts reflected above include the relinquishment of $350 million in the aggregate of incentive distributions that would potentially be made to ETE over the first forty fiscal quarters commencing immediately after the consummation of the Susser Merger. Such relinquishments would cease upon the agreement of an exchange of the Sunoco LP general partner interest and the incentive distribution rights between ETE and ETP.

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 declared by ETP during the periods presented are as follows:

	Record Date	Payment Date	Rate
December 31, 2011	February 7, 2012	February 14, 2012	$ 0.8938
March 31, 2012	May 4, 2012	May 15, 2012	0.8938
June 30, 2012	August 6, 2012	August 14, 2012	0.8938
September 30, 2012	November 6, 2012	November 14, 2012	0.8938
December 31, 2012	February 7, 2013	February 14, 2013	0.8938
March 31, 2013	May 6, 2013	May 15, 2013	0.8938
June 30, 2013	August 5, 2013	August 14, 2013	0.8938
September 30, 2013	November 4, 2013	November 14, 2013	0.9050
December 31, 2013	February 7, 2014	February 14, 2014	0.9200
March 31, 2014	May 5, 2014	May 15, 2014	0.9350
June 30, 2014	August 4, 2014	August 14, 2014	0.9550
September 30, 2014	November 3, 2014	November 14, 2014	0.9750
December 31, 2014	February 6, 2015	February 13, 2015	0.9950

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,		
	2014	2013	2012
Limited Partners:			
Common Units	$ 1,298	$ 1,265	$ 955
Class H Units	219	105	—
General Partner interest	21	20	20
Incentive distributions	754	701	529
IDR relinquishments related to previous transactions	(250)	(199)	(90)
Total ETP distributions	$ 2,042	$ 1,892	$ 1,414

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.

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$ 0.2725
March 31, 2013	May 9, 2013	May 15, 2013	0.2863
June 30, 2013	August 8, 2013	August 14, 2013	0.3000
September 30, 2013	November 8, 2013	November 14, 2013	0.3150
December 31, 2013	February 10, 2014	February 14, 2014	0.3312
March 31, 2014	May 9, 2014	May 15, 2014	0.3475
June 30, 2014	August 8, 2014	August 14, 2014	0.3650
September 30, 2014	November 7, 2014	November 14, 2014	0.3825
December 31, 2014	February 9, 2015	February 13, 2015	0.4000

Sunoco Logistics Unit Split

On May 5, 2014, Sunoco Logistics' board of directors declared a two-for-one split of Sunoco Logistics common units. The unit split resulted in the issuance of one additional Sunoco Logistics common unit for every one unit owned as of the close of business on June 5, 2014. The unit split was effective June 12, 2014. All Sunoco Logistics unit and per unit information included in this report is presented on a post-split basis.

The total amounts of Sunoco Logistics distributions declared during the periods 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):

	Years Ended December 31,		
	2014	2013	2012
Limited Partners			
Common units held by public	$ 225	$ 173	$ 39
Common units held by ETP	100	82	18
General Partner interest held by ETP	10	5	1
Incentive distributions held by ETP	175	117	22
Total distributions declared	$ 510	$ 377	$ 80

Cash Distributions Paid by Sunoco LP

Sunoco LP 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.

Distributions declared by Sunoco LP subsequent to our acquisition on August 29, 2014 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2014	November 18, 2014	November 28, 2014	$ 0.5457
December 31, 2014	February 17, 2015	February 27, 2015	0.6000

The total amounts of Sunoco LP distributions declared during the periods 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, 2014
Limited Partners:	
Common units held by public	$ 22
Common units held by ETP	17
General Partner interest and incentive distributions held by ETP	1
Total distributions declared	$ 40

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 declared by Regency during the periods presented are as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2011	February 6, 2012	February 13, 2012	$ 0.4600
March 31, 2012	May 7, 2012	May 14, 2012	0.4600
June 30, 2012	August 6, 2012	August 14, 2012	0.4600
September 30, 2012	November 6, 2012	November 14, 2012	0.4600
December 31, 2012	February 7, 2013	February 14, 2013	0.4600
March 31, 2013	May 6, 2013	May 13, 2013	0.4600
June 30, 2013	August 5, 2013	August 14, 2013	0.4650
September 30, 2013	November 4, 2013	November 14, 2013	0.4700
December 31, 2013	February 7, 2014	February 14, 2014	0.4750
March 31, 2014	May 8, 2014	May 15, 2014	0.4800
June 30, 2014	August 7, 2014	August 14, 2014	0.4900
September 30, 2014	November 4, 2014	November 14, 2014	0.5025
December 31, 2014	February 6, 2015	February 13, 2015	0.5025

The total amounts of Regency distributions declared (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,		
	2014	2013	2012
Limited Partners	$ 775	$ 390	$ 314
General Partner Interest	6	5	5
Incentive distributions	33	12	8
IDR relinquishments related to previous transactions	(3)	(3)	—
Total Regency distributions	$ 811	$ 404	$ 327

New Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In April 2014, the FASB issued Accounting Standards Update No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* ("ASU 2014-08"), which changed the requirements for reporting discontinued operations. Under ASU 2014-08, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has or will have a major effect on an entity's operations and financial results. ASU 2014-08 is effective for all disposals or classifications as held for sale of components of an entity that occur within fiscal years beginning after December 15, 2014, and early adoption is permitted. We expect to adopt this standard for the year ending December 31, 2015. ASU 2014-08 could have an impact on whether transactions will be reported in discontinued operations in the future, as well as the disclosures required when a component of an entity is disposed.

Estimates and Critical Accounting Policies

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

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage 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, 2014 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, depletion 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. A portion of our gasoline and diesel sales are to wholesale customers on a consignment basis, in which we retain title to inventory, control access to and sale of fuel inventory, and recognize revenue at the time the fuel is sold to the ultimate customer. We typically own the fuel dispensing equipment and underground storage tanks at consignment sites, and in some cases we own the entire site and have entered into an operating lease whit the wholesale customer operating the site. In addition, our retail outlets derive other income from lottery ticket sales, money orders, prepaid phone cards and wireless services, ATM transactions, car washes, movie rental and other ancillary product and service offerings. Some of Sunoco, Inc.’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 recorded on a net commission basis and 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. 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.

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, 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 Obligations. 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 certain amounts recorded by Panhandle, Sunoco Logistics and ETP's retail marketing operations discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2014 and 2013, in most cases because the settlement dates were indeterminable. Although a number of other onshore assets in Panhandle's system are subject to agreements or regulations that give rise to an ARO upon Panhandle'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, Inc. 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, Inc. 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, 2014, 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 12 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" 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, 2014, 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 $116 million have been included in ETE’s consolidated balance sheet as of December 31, 2014. All of the deferred income tax assets attributable to state and federal NOL benefits expire before 2033 as more fully described below. The state NOL carryforward benefits of $111 million (net of federal benefit) begin to expire in 2014 with a substantial portion expiring between 2029 and 2033. The federal NOLs of $5 million ($1 million in benefits) will expire in 2032 and 2033. Less than $1 million of federal tax alternative minimum tax credit carryforwards remained at December 31, 2014. We have determined that a valuation allowance totaling $84 million (net of federal income tax effects) is required for the state NOLs at December 31, 2014 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.

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, 2014 and 2013, 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, 2014. 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 Sunoco LP and Susser Holdings Corporation, both consolidated subsidiaries, as of December 31, 2014 and for the period from September 1, 2014 to December 31, 2014, whose combined statements reflect total assets constituting 7 percent of consolidated total assets as of December 31, 2014, and total revenues of 5 percent of consolidated total revenues for the year then ended. 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 Sunoco LP and Susser Holdings Corporation, is based solely on the reports of the other auditors. We did not audit the financial statements of Sunoco Logistics Partners L.P., a consolidated subsidiary, for the period from October 5, 2012 to December 31, 2012, which statements reflect revenues of 19 percent of consolidated total revenues for the year ended December 31, 2012. 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. 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 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 Energy Transfer Equity, L.P. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 9, the accompanying consolidated financial statements have been adjusted to reflect the unit split completed on July 27, 2015. As discussed in Note 16, the accompanying consolidated financial statements have been adjusted to reflect the change in the Partnership's reportable segments.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 2, 2015 (except for all unit and per unit amounts as discussed in Note 9 and for Note 16, as to which the date is November 24, 2015)

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

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 847	$ 590
Accounts receivable, net	3,378	3,658
Accounts receivable from related companies	35	63
Inventories	1,467	1,807
Exchanges receivable	44	67
Price risk management assets	81	39
Other current assets	301	312
Total current assets	6,153	6,536
PROPERTY, PLANT AND EQUIPMENT	45,018	33,917
ACCUMULATED DEPRECIATION AND DEPLETION	(4,726)	(3,235)
	40,292	30,682
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	3,659	4,014
NON-CURRENT PRICE RISK MANAGEMENT ASSETS	10	18
GOODWILL	7,865	5,894
INTANGIBLE ASSETS, net	5,582	2,264
OTHER NON-CURRENT ASSETS, net	908	922
Total assets	$ 64,469	$ 50,330

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, 2014	December 31, 2013
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 3,349	$ 3,834
Accounts payable to related companies	19	14
Exchanges payable	184	284
Price risk management liabilities	21	53
Accrued and other current liabilities	2,201	1,678
Current maturities of long-term debt	1,008	637
Total current liabilities	6,782	6,500
LONG-TERM DEBT, less current maturities	29,653	22,562
DEFERRED INCOME TAXES	4,325	3,865
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	154	73
OTHER NON-CURRENT LIABILITIES	1,193	1,019
COMMITMENTS AND CONTINGENCIES (Note 12)		
REDEEMABLE NONCONTROLLING INTERESTS	15	—
PREFERRED UNITS OF SUBSIDIARY (Note 7)	33	32
EQUITY:		
General Partner	(1)	(3)
Limited Partners:		
Common Unitholders (1,077,533,798 and 1,119846,600 units authorized, issued and outstanding as of December 31, 2014 and 2013, respectively)	648	1,066
Class D Units (3,080,000 units authorized, issued and outstanding)	22	6
Accumulated other comprehensive income (loss)	(5)	9
Total partners’ capital	664	1,078
Noncontrolling interest	21,650	15,201
Total equity	22,314	16,279
Total liabilities and equity	$ 64,469	$ 50,330

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,		
	2014	2013	2012
REVENUES:			
Natural gas sales	$ 5,386	$ 3,842	$ 2,705
NGL sales	5,845	3,618	2,253
Crude sales	16,416	15,477	2,872
Gathering, transportation and other fees	3,733	3,097	2,386
Refined product sales	19,437	18,479	5,299
Other	4,874	3,822	1,449
Total revenues	55,691	48,335	16,964
COSTS AND EXPENSES:			
Cost of products sold	48,389	42,554	13,088
Operating expenses	2,127	1,695	1,118
Depreciation, depletion and amortization	1,724	1,313	871
Selling, general and administrative	611	533	527
Goodwill impairments	370	689	—
Total costs and expenses	53,221	46,784	15,604
OPERATING INCOME	2,470	1,551	1,360
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(1,369)	(1,221)	(1,018)
Bridge loan related fees	—	—	(62)
Equity in earnings of unconsolidated affiliates	332	236	212
Gain on deconsolidation of Propane Business	—	—	1,057
Gain on sale of AmeriGas common units	177	87	—
Losses on extinguishments of debt	(25)	(162)	(123)
Gains (losses) on interest rate derivatives	(157)	53	(19)
Non-operating environmental remediation	—	(168)	—
Other, net	(11)	(1)	30
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	1,417	375	1,437
Income tax expense from continuing operations	357	93	54
INCOME FROM CONTINUING OPERATIONS	1,060	282	1,383
Income (loss) from discontinued operations	64	33	(109)
NET INCOME	1,124	315	1,274
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	491	119	970
NET INCOME ATTRIBUTABLE TO PARTNERS	633	196	304
GENERAL PARTNER’S INTEREST IN NET INCOME	2	—	2
CLASS D UNITHOLDER’S INTEREST IN NET INCOME	2	—	—
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 629	$ 196	$ 302
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:			
Basic	$ 0.58	$ 0.17	$ 0.29
Diluted	$ 0.57	$ 0.17	$ 0.29
NET INCOME PER LIMITED PARTNER UNIT:			
Basic	$ 0.58	$ 0.18	$ 0.29
Diluted	$ 0.58	$ 0.18	$ 0.29

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,		
	2014	2013	2012
Net income	$ 1,124	$ 315	$ 1,274
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	3	(4)	(17)
Change in value of derivative instruments accounted for as cash flow hedges	—	(1)	12
Change in value of available-for-sale securities	1	2	—
Actuarial gain (loss) relating to pension and other postretirement benefits	(113)	66	(10)
Foreign currency translation adjustment	(2)	(1)	—
Change in other comprehensive income from unconsolidated affiliates	(6)	17	(9)
	(117)	79	(24)
Comprehensive income	1,007	394	1,250
Less: Comprehensive income attributable to noncontrolling interest	388	181	959
Comprehensive income attributable to partners	$ 619	$ 213	$ 291

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

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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, 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
ETP 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
Distributions to partners	(2)	(817)	(2)	—	—	(821)
Distributions to noncontrolling interest	—	—	—	—	(1,905)	(1,905)
Subsidiary units issued for cash	—	148	2	—	2,907	3,057
Subsidiary units issued in certain acquisitions	—	211	—	—	5,604	5,815
Subsidiary units redeemed in Lake Charles LNG Transaction	2	480	—	—	(482)	—
Purchase of additional Regency Units	—	(99)	—	—	99	—
Subsidiary acquisition of a noncontrolling interest	—	—	—	—	(319)	(319)
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	—	14	—	51	65
Capital contributions received from noncontrolling interest	—	—	—	—	139	139
Other, net	—	30	—	—	(33)	(3)
Units repurchased under buyback program	—	(1,000)	—	—	—	(1,000)
Other comprehensive loss, net of tax	—	—	—	(14)	(103)	(117)
Net income	2	629	2	—	491	1,124
Balance, December 31, 2014	$ (1)	$ 648	$ 22	$ (5)	$ 21,650	$ 22,314

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,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 1,124	$ 315	$ 1,274
Reconciliation of net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,724	1,313	871
Deferred income taxes	(50)	43	51
Amortization included in interest expense	(51)	(55)	(13)
Bridge loan related fees	—	—	62
Non-cash compensation expense	82	61	47
Goodwill impairment	370	689	—
Gain on sale of AmeriGas common units	(177)	(87)	—
Gain on deconsolidation of Propane Business	—	—	(1,057)
Gain on curtailment of other postretirement benefit plans	—	—	(15)
Losses on extinguishments of debt	25	162	123
(Gains) losses on disposal of assets	(1)	2	4
Equity in earnings of unconsolidated affiliates	(332)	(236)	(212)
Distributions from unconsolidated affiliates	291	313	208
Inventory valuation adjustments	473	(3)	75
Other non-cash	(72)	51	211
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations (see Note 2)	(231)	(149)	(551)
Net cash provided by operating activities	3,175	2,419	1,078
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for Southern Union Merger, net of cash received (See Note 3)	—	—	(2,972)
Cash paid for all other acquisitions	(2,367)	(405)	(10)
Cash proceeds from contribution and sale of propane operations	—	—	1,443
Cash proceeds from the sale of AmeriGas common units	814	346	—
Proceeds from the sale of discontinued operations	77	1,008	207
Proceeds from the sale of other assets	62	89	44
Capital expenditures (excluding allowance for equity funds used during construction)	(5,381)	(3,505)	(3,271)
Contributions in aid of construction costs	45	52	35
Contributions to unconsolidated affiliates	(334)	(3)	(37)
Distributions from unconsolidated affiliates in excess of cumulative earnings	136	419	189
Change in restricted cash	172	(348)	5
Other	(19)	—	171
Net cash used in investing activities	(6,795)	(2,347)	(4,196)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	18,375	12,934	12,870
Repayments of long-term debt	(13,886)	(11,951)	(8,848)
Subsidiary equity offerings, net of issue costs	3,057	1,759	1,103
Distributions to partners	(821)	(733)	(666)
Distributions to noncontrolling interests	(1,905)	(1,428)	(1,017)
Debt issuance costs	(77)	(87)	(112)
Capital contributions received from noncontrolling interest	139	18	42
Redemption of Preferred Units	—	(340)	—
Units repurchased under buyback program	(1,000)	—	—
Other, net	(5)	(26)	(8)
Net cash provided by financing activities	3,877	146	3,364
INCREASE IN CASH AND CASH EQUIVALENTS	257	218	246
CASH AND CASH EQUIVALENTS, beginning of period	590	372	126
CASH AND CASH EQUIVALENTS, end of period	$ 847	$ 590	$ 372

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, 2014, 2013 and 2012, 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 9, in January 2014 and July 2015, the Partnership completed two-for-one splits 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 splits for all periods presented.

At December 31, 2014, 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	30.8	57.2
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; and
- our wholly-owned subsidiary, Lake Charles LNG. Lake Charles LNG was acquired from ETP in February 2014.

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 2014 presentation. These reclassifications had no impact on net income or total equity.

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, ETE Common Holdings, LLC, Regency, Regency GP, Regency LLC, Panhandle (or Southern Union prior to its merger into Panhandle in January 2014), Sunoco, Inc., Sunoco Logistics, Sunoco LP, Susser and ETP Holdco. References to the "Parent Company" mean Energy Transfer Equity, L.P. on a stand-alone basis.

As discussed in Note 3, ETP completed its acquisition of Regency in April 2015; therefore, the Investment in ETP segment amounts have been retrospectively adjusted to reflect Regency for the periods presented, and the Investment in Regency is no longer presented in a separate segment.

In 2014, our consolidated subsidiaries, Trunkline LNG Company, LLC, Trunkline LNG Export, LLC and Susser Petroleum Partners LP, changed their names to Lake Charles LNG Company, LLC, Lake Charles LNG Export, LLC and Sunoco LP, respectively. All references to these subsidiaries throughout this document reflect the new names of those subsidiaries, regardless of whether the disclosure relates to periods or events prior to the dates of the name changes.

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 18 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 is a publicly traded partnership whose 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.
  - 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.
  - ETP Holdco, a Delaware limited liability company that indirectly owns Panhandle and Sunoco, Inc. Panhandle and Sunoco, Inc. 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, 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, Inc. owns and operates retail marketing assets, which sell gasoline and middle distillates at retail locations and operates convenience stores primarily on the east coast and in the midwest region of the United States. Effective June 1, 2014, ETP combined certain Sunoco, Inc. retail assets with another wholly-owned subsidiary of ETP to form a limited liability company owned by ETP and Sunoco, Inc.

- Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of products, crude oil and NGL pipelines, terminalling and storage assets, and refined products, crude oil and NGL acquisition and marketing assets.

- ETP owns an indirect 100% equity interest in Susser and the general partner interest, incentive distribution rights and a 42.8% limited partner interest in Sunoco LP. Susser operates convenience stores in Texas, New Mexico and Oklahoma. Sunoco LP distributes motor fuels to convenience stores and retail fuel outlets in Texas, New Mexico, Oklahoma, Kansas and Louisiana and other commercial customers. As discussed in Note 3, in October 2014, Sunoco LP acquired MACS from ETP.

- Regency is a limited partnership engaged in the gathering and processing, compression, treating and transportation of natural gas; the transportation, fractionation and storage of NGLs; the gathering, transportation and terminaling of oil (crude and/or condensate, a lighter oil) received from producers; natural gas and NGL marketing and trading, and the management of coal and natural resource properties in the United States. 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. Regency also holds a 30% interest in Lone Star.

- Lake Charles LNG operates a LNG import terminal, which has approximately 9.0 Bcf of above ground LNG storage capacity and re-gasification facilities on Louisiana's Gulf Coast near Lake Charles, Louisiana. Lake Charles LNG is engaged in interstate commerce and is subject to the rules, regulations and accounting requirements of the FERC.

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, depletion 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.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In April 2014, the FASB issued Accounting Standards Update No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* ("ASU 2014-08"), which changed the requirements for reporting discontinued operations. Under ASU 2014-08, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has or will have a major effect on an entity's operations and financial results. ASU 2014-08 is effective for all disposals or classifications as held for sale of components of an entity that occur within fiscal years beginning after December 15, 2014, and early adoption is permitted. We expect to adopt this standard for the year ending December 31, 2015. ASU 2014-08 could have an impact on whether transactions will be reported in discontinued operations in the future, as well as the disclosures required when a component of an entity is disposed.

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. A portion of our gasoline and diesel sales are to wholesale customers on a consignment basis, in which we retain title to inventory, control access to and sale of fuel inventory, and recognize revenue at the time the fuel is sold to the ultimate customer. We typically own the fuel dispensing equipment and underground storage tanks at consignment sites, and in some cases we own the entire site and have entered into an operating lease whit the wholesale customer operating the site. In addition, our retail outlets derive other income from lottery ticket sales, money orders, prepaid phone cards and wireless services, ATM transactions, car washes, movie rental and other ancillary product and service offerings. Some of Sunoco, Inc.'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 recorded on a net commission basis and 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, NGL, condensate and salt water gathering, processing and transportation, (iii) contract compression and treating services and (iv) coal royalties. 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, 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 and NGLs at a price approximating the index price to third parties. Regency 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 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.

Regency recognizes coal royalties revenues on the basis of tons of coal sold by its lessees and the corresponding revenues from those sales. Regency does not have access to actual production and revenues information until 30 days following the month of production. Therefore, financial results include estimated revenues and accounts receivable for the month of production. Regency records any differences between the actual amounts ultimately received or paid and the original estimates in the period they become finalized. Most lessees must make minimum monthly or annual payments that are generally recoverable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recovers a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalties revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the deferred income attributable to the minimum payment is recognized as minimum rental revenues, which is a component of other revenues on our consolidated statements of operations. Other liabilities on the balance sheet also include deferred unearned income from a coal services facility lease, which is recognized as other income as it is earned.

Investment in Lake Charles LNG

Lake Charles LNG's revenues from storage and re-gasification of natural gas are based on capacity reservation charges and, to a lesser extent, commodity usage charges. Reservation revenues are based on contracted rates and capacity reserved by the customers and recognized monthly. Revenues from commodity usage charges are also recognized monthly and represent the recovery of electric power charges at Lake Charles LNG's terminal.

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.

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,		
	2014	2013	2012
Accounts receivable	$ 600	$ (556)	$ 267
Accounts receivable from related companies	30	64	(9)
Inventories	51	(254)	(258)
Exchanges receivable	18	(8)	14
Other current assets	133	(81)	597
Other non-current assets, net	(6)	(23)	(129)
Accounts payable	(850)	541	(989)
Accounts payable to related companies	5	(140)	92
Exchanges payable	(99)	128	—
Accrued and other current liabilities	(59)	192	(159)
Other non-current liabilities	(73)	147	26
Price risk management assets and liabilities, net	19	(159)	(3)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (231)	$ (149)	$ (551)

Non-cash investing and financing activities and supplemental cash flow information were as follows:

	Years Ended December 31,		
	2014	2013	2012
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 643	$ 226	$ 420
Net gains (losses) from subsidiary common unit transactions	$ 744	$ (384)	$ 80
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
Subsidiary issuance of common units in connection with certain acquisitions	$ —	$ —	$ 2,295
Subsidiary issuances of common units in connection with PVR, Hoover and Eagle Rock Midstream acquisitions	$ 4,281	$ —	$ —
Subsidiary issuances of common units in connection with the Susser Merger	$ 908	$ —	$ —
Long-term debt assumed in PVR Acquisition	$ 1,887	$ —	$ —
Long-term debt exchanged in Eagle Rock Midstream Acquisition	$ 499	$ —	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,416	$ 1,256	$ 997
Cash paid for income taxes	$ 345	$ 58	$ 23

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,	
	2014	2013
Natural gas and NGLs	$ 392	$ 577
Crude oil	364	488
Refined products	392	543
Appliances, parts and fittings and other	319	199
Total inventories	$ 1,467	$ 1,807

During the year ended December 31, 2014, the Partnership recorded write downs of $473 million on its crude oil, refined products and NGL inventories as a result of a decline in the market price of these products. The write-down was calculated based upon current replacement costs.

ETP utilizes commodity derivatives to manage price volatility associated with certain of its natural gas inventory and designates certain of these derivatives as fair value hedges for accounting purposes. Changes in fair value of the designated hedged inventory have been 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,	
	2014	2013
Deposits paid to vendors	$ 65	$ 49
Deferred income taxes	14	—
Prepaid expenses and other	222	263
Total other current assets	$ 301	$ 312

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. For the Lake Charles LNG project, a portion of the management fees are capitalized. 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.

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,	
	2014	2013
Land and improvements	$ 1,307	$ 881
Buildings and improvements (1 to 45 years)	1,922	939
Pipelines and equipment (5 to 83 years)	27,149	21,494
Natural gas and NGL storage facilities (5 to 46 years)	1,214	1,083
Bulk storage, equipment and facilities (2 to 83 years)	4,010	1,933
Tanks and other equipment (5 to 40 years)	58	1,697
Retail equipment (2 to 99 years)	515	450
Vehicles (1 to 25 years)	203	156
Right of way (20 to 83 years)	2,451	2,190
Furniture and fixtures (2 to 25 years)	59	51
Linepack	119	118
Pad gas	44	52
Natural resources	454	—
Other (1 to 30 years)	999	708
Construction work-in-process	4,514	2,165
	45,018	33,917
Less – Accumulated depreciation and depletion	(4,726)	(3,235)
Property, plant and equipment, net	$ 40,292	$ 30,682

We recognized the following amounts of depreciation expense and capitalized interest expense for the periods presented:

	Years Ended December 31,		
	2014	2013	2012
Depreciation expense	$ 1,457	$ 1,128	$ 801
Capitalized interest, excluding AFUDC	$ 113	$ 43	$ 99

Depletion expense related to Regency's natural resources operations was $11 million for the year ended December 31, 2014. Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by Regency's own geologists. Regency's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. From time to time, Regency carries out core-hole drilling activities on coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-hole drilling activities are expensed as incurred. Regency depletes timber using a methodology consistent with the units-of-production method, which is based on the quantity of timber harvested. Regency determines depletion of oil and gas royalty interests by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves.

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 liquids transportation and services operations and all others, including all of Regency's reporting units and Lake Charles LNG.

Changes in the carrying amount of goodwill were as follows:

	Investment in ETP	Investment in Lake Charles LNG	Corporate, Other and Eliminations	Total
Balance, December 31, 2012	$ 6,396	$ 873	$ (835)	$ 6,434
Goodwill acquired	156	—	—	156
Goodwill impairment	(689)	(689)	689	(689)
Other	(7)	—	—	(7)
Balance, December 31, 2013	5,856	184	(146)	5,894
Goodwill acquired	2,340	—	—	2,340
Lake Charles LNG Transaction (1)	(184)	—	184	—
Goodwill impairment	(370)	—	—	(370)
Other	—	—	1	1
Balance, December 31, 2014	$ 7,642	$ 184	$ 39	$ 7,865

(1) As discussed in Note 3, ETP completed the transfer to ETE of Lake Charles LNG on February 19, 2014. Therefore, the December 31, 2012 and 2013 goodwill balances include goodwill attributable to Lake Charles LNG of $873 million and$184 million, respectively, in both the investment in ETP and investment in Lake Charles LNG segments that was correspondingly included in the elimination column. The transaction was effective January 1, 2014.

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 $1.97 billion during the year ended December 31, 2014 primarily due to the Susser Merger and PVR Acquisition where we recorded goodwill of $1.73 billion and $370 million, respectively, offset by an impairment of $370 million. The additional goodwill recorded during the years ended December 31, 2014 and 2013 is not expected to be deductible for tax purposes.

During the fourth quarter of 2014, a $370 million goodwill impairment was recorded related to Regency's Permian Basin gathering and processing operations. The decline in estimated fair value of that reporting unit was primarily driven by the significant decline in commodity prices in the fourth quarter of 2014, and the resulting impact to future commodity prices as well as increases in future estimated operations and maintenance expenses. An assessment of these factors in the fourth quarter of 2014 led to a conclusion that the estimated fair value of Regency's Permian reporting unit was less than its carrying amount.

During the fourth quarter of 2013, ETP performed a goodwill impairment test on its Lake Charles 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 Lake Charles 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 Lake Charles 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 Lake Charles 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, 2014		December 31, 2013	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 5,144	$ (485)	$ 2,135	$ (264)
Trade names (15 to 20 years)	556	(15)	66	(12)
Patents (9 years)	48	(11)	48	(6)
Other (1 to 15 years)	36	(7)	7	(4)
Total amortizable intangible assets	5,784	(518)	2,256	(286)
Non-amortizable intangible assets:				
Trademarks	316	—	294	—
Total intangible assets	$ 6,100	$ (518)	$ 2,550	$ (286)

Aggregate amortization expense of intangibles assets was as follows:

	Years Ended December 31,		
	2014	2013	2012
Reported in depreciation, depletion and amortization	$ 219	$ 120	$ 70

Estimated aggregate amortization expense of intangible assets for the next five years was as follows:

Years Ending December 31:	
2015	$ 263
2016	260
2017	260
2018	259
2019	256

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,	
	2014	2013
Unamortized financing costs (3 to 30 years)	$ 203	$ 167
Regulatory assets	85	86
Deferred charges	220	144
Restricted funds	177	378
Other	223	147
Total other non-current assets, net	$ 908	$ 922

Restricted funds primarily consisted of restricted cash held in our wholly-owned captive insurance companies.

Asset Retirement Obligations

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 certain amounts recorded by Panhandle, Sunoco Logistics and ETP's retail marketing operations. discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2014 and 2013, in most cases because the settlement dates were indeterminable. Although a number of other onshore assets in Panhandle's system are subject to agreements or regulations that give rise to an ARO upon Panhandle'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, Inc. has legal asset retirement obligations for several other assets at its previously owned 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, Inc. 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 segment recorded as other non-current liabilities in our consolidated balance sheets:

	December 31,	
	2014	2013
Interstate transportation and storage operations	$ 60	$ 55
Retail marketing operations	87	84
Investment in Sunoco Logistics	41	41
	$ 188	$ 180

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, 2014, 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,	
	2014	2013
Interest payable	$ 440	$ 357
Customer advances and deposits	103	142
Accrued capital expenditures	673	260
Accrued wages and benefits	233	173
Taxes payable other than income taxes	236	211
Income taxes payable	54	4
Deferred income taxes	99	119
Other	363	412
Total accrued and other current liabilities	$ 2,201	$ 1,678

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 loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations as of December 31, 2014 was $31.68 billion and $30.66 billion, respectively. As of December 31, 2013, the aggregate fair value and carrying amount of our consolidated debt obligations was $23.97 billion and $23.20 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, 2014 and 2013 based on inputs used to derive their fair values:

	Fair Value Measurements at December 31, 2014			
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Interest rate derivatives	$ 3	$ —	$ 3	$ —
Commodity derivatives:				
Condensate — Forward Swaps	36	—	36	—
Natural Gas:				
Basis Swaps IFERC/NYMEX	19	19	—	—
Swing Swaps IFERC	26	1	25	—
Fixed Swaps/Futures	566	541	25	—
Forward Physical Contracts	1	—	1	—
Power:				
Forwards	3	—	3	—
Futures	4	4	—	—
Natural Gas Liquids — Forwards/Swaps	69	46	23	—
Refined Products — Futures	21	21	—	—
Total commodity derivatives	745	632	113	—
Total assets	$ 748	$ 632	$ 116	$ —
Liabilities:				
Interest rate derivatives	$ (155)	$ —	$ (155)	$ —
Embedded derivatives in the Regency Preferred Units	(16)	—	—	(16)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(18)	(18)	—	—
Swing Swaps IFERC	(25)	(2)	(23)	—
Fixed Swaps/Futures	(490)	(490)	—	—
Power:				
Forwards	(4)	—	(4)	—
Futures	(2)	(2)	—	—
Natural Gas Liquids — Forwards/Swaps	(32)	(32)	—	—
Refined Products — Futures	(7)	(7)	—	—
Total commodity derivatives	(578)	(551)	(27)	—
Total liabilities	$ (749)	$ (551)	$ (182)	$ (16)

	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	—
Natural Gas Liquids — 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)	—
Natural Gas Liquids — 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)

At December 31, 2013, the fair value of the Lake Charles 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 Lake Charles 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.

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, 2014
Embedded derivatives in the Regency Preferred Units	Credit Spread	4.76%
	Volatility	35.80%

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, 2014. There were no transfers between the fair value hierarchy levels during the years ended December 31, 2014 or 2013.

Balance, December 31, 2013	$	(19)
Net unrealized gains included in other income (expense)		3
Balance, December 31, 2014	$	(16)

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 are included in cost of products sold, except for shipping and handling costs related to fuel consumed for compression and treating which are included in operating expenses.

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 $2.46 billion, $2.22 billion and $573 million for the years ended December 31, 2014, 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 our subsidiaries' 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 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, 2014, 2013 and 2012, 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. These corporate subsidiaries include Susser and ETP Holdco, which owns Sunoco, Inc. and Panhandle. 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.

Unit-Based Compensation

For awards of restricted units, we recognize compensation expense over the vesting period based on the grant-date fair value, which is determined based on the market price of our common units on the grant date. For awards of cash restricted units, we remeasure the fair value of the award at the end of each reporting period based on the market price of our common units as of the reporting date, and the fair value is recorded in other non-current liabilities on our consolidated balance sheets.

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:

2015 Transactions

Regency Merger

See Note 16 for a description of the Regency Merger.

In April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the "Regency Merger"). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new ETP Series A Preferred Units.

In connection with the transaction, ETE, which owns the general partner and 100% of the incentive distribution rights of ETP, will reduce the incentive distributions it receives from ETP by a total of $320 million over a five-year period. The IDR subsidy will be $80 million in the first year post-closing and $60 million per year for the following four years.

ETP and Regency are under common control of ETE; therefore, we accounted for the Regency Merger at historical cost as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency beginning May 26, 2010 (the date ETE acquired Regency's general partner).

2014 Transactions

Susser Merger

In August 2014, ETP and Susser completed the merger of an indirect wholly-owned subsidiary of ETP, with and into Susser, with Susser surviving the merger as a subsidiary of ETP for total consideration valued at approximately $1.8 billion (the "Susser Merger"). The total consideration paid in cash was approximately $875 million and the total consideration paid in equity was approximately 15.8 million ETP Common Units. The Susser Merger broadens ETP's retail geographic footprint and provides synergy opportunities and a platform for future growth.

In connection with the Susser Merger, ETP acquired an indirect 100% equity interest in Susser and the general partner interest and the incentive distribution rights in Sunoco LP, approximately 11 million Sunoco LP common and subordinated units, and Susser's existing retail operations, consisting of 630 convenience store locations.

Effective with the closing of the transaction, Susser ceased to be a publicly traded company and its common stock discontinued trading on the NYSE.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the Susser 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 as of December 31, 2014 reflected the preliminary purchase price allocations based on available information. Management is reviewing the valuation and confirming the results to determine the final purchase price allocation.

The following table summarizes the preliminary assets acquired and liabilities assumed recognized as of the merger date:

	Susser
Total current assets	$ 446
Property, plant and equipment	1,069
Goodwill[1]	1,734
Intangible assets	611
Other non-current assets	17
	3,877
Total current liabilities	377
Long-term debt, less current maturities	564
Deferred income taxes	488
Other non-current liabilities	39
Noncontrolling interest	626
	2,094
Total consideration	1,783
Cash received	67
Total consideration, net of cash received	$ 1,716

(1) None of the goodwill is expected to be deductible for tax purposes.

The fair values of the assets acquired and liabilities assumed is being determined using various valuation techniques, including the income and market approaches.

ETP incurred merger related costs related to the Susser Merger of $25 million during the year ended December 31, 2014. Our consolidated statements of operations for the year ended December 31, 2014 reflected revenue and net income related to Susser of $2.32 billion and $105 million, respectively.

No pro forma information has been presented for the Susser Merger, as the impact of this acquisition was not material in relation to our consolidated results of operations.

MACS to Sunoco LP

In October 2014, Sunoco LP acquired MACS from a subsidiary of ETP in a transaction valued at approximately $768 million (the “MACS Transaction”). The transaction included approximately 110 company-operated retail convenience stores and 200 dealer-operated and consignment sites from MACS, which had originally been acquired by ETP in October 2013. The consideration paid by Sunoco LP consisted of approximately 4 million Sunoco LP common units issued to ETP and $556 million in cash, subject to customary closing adjustments. Sunoco LP initially financed the cash portion by utilizing availability under its revolving credit facility. In October 2014 and November 2014, Sunoco LP partially repaid borrowings on its revolving credit facility with aggregate net proceeds of $405 million from a public offering of 9.1 million Sunoco LP common units.

Lake Charles LNG Transaction

On February 19, 2014, ETP completed the transfer to ETE of Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, in exchange for the redemption by ETP of 18.7 million ETP Common Units held by ETE (the “Lake Charles LNG Transaction”). The transaction was effective as of January 1, 2014, at which time ETP deconsolidated Lake Charles LNG.

In connection with ETE’s acquisition of Lake Charles LNG, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG’s regasification facility and the development of a liquefaction project at Lake Charles 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 9.

Panhandle Merger

On January 10, 2014, Panhandle consummated a merger with Southern Union, the indirect parent of Panhandle at the time of the merger, and PEPL Holdings, a wholly-owned subsidiary of Southern Union and the sole limited partner of Panhandle at the time of the merger, 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 material operations of its own, other than its ownership of Panhandle and noncontrolling interests 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.

Regency's Acquisition of PVR Partners, L.P.

On March 21, 2014, Regency acquired PVR for a total purchase price of $5.7 billion (based on Regency's closing price of $27.82 per Regency Common Unit on March 21, 2014), including $1.8 billion principal amount of assumed debt (the "PVR Acquisition"). PVR unitholders received (on a per unit basis) 1.02 Regency Common Units and a one-time cash payment of $36 million, which was funded through borrowings under Regency's revolving credit facility. The PVR Acquisition enhances 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 accounted for the PVR Acquisition 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 statement of operations for the year ended December 31, 2014 included revenues and net income attributable to PVR's operations of $956 million and $166 million, respectively.

Regency completed the evaluation of the assigned fair values to the assets acquired and liabilities assumed. The total purchase price was allocated as follows:

Assets	At March 21, 2014
Current assets	$ 149
Property, plant and equipment	2,716
Investment in unconsolidated affiliates	62
Intangible assets (average useful life of 30 years)	2,717
Goodwill	370
Other non-current assets	18
Total assets acquired	6,032
Liabilities	
Current liabilities	168
Long-term debt	1,788
Premium related to senior notes	99
Non-current liabilities	30
Total liabilities assumed	2,085
Net assets acquired	$ 3,947

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

Regency's Acquisition of Eagle Rock's Midstream Business

On July 1, 2014, Regency acquired Eagle Rock's midstream business (the "Eagle Rock Midstream Acquisition") for $1.3 billion, including the assumption of $499 million of Eagle Rock's 8.375% senior notes due 2019. The remainder of the purchase price was funded by $400 million in Regency Common Units sold to a wholly-owned subsidiary of ETE, 8.2 million Regency Common Units issued to Eagle Rock and borrowings under Regency's revolving credit facility. Regency accounted for the Eagle Rock Midstream Acquisition 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. This acquisition complements Regency's core gathering and processing business and further diversifies Regency's geographic presence in the Mid-Continent region, east Texas and south Texas. Our consolidated statement of operations for the year ended December 31, 2014 included revenues and net income attributable to Eagle Rock's operations of $903 million and $30 million, respectively.

Regency's evaluation of the assigned fair values is ongoing. The table below represents a preliminary allocation of the total purchase price:

Assets	At July 1, 2014
Current assets	$ 120
Property, plant and equipment	1,295
Other non-current assets	4
Goodwill[1]	49
Total assets acquired	1,468
Liabilities	
Current liabilities	116
Long-term debt	499
Other non-current liabilities	12
Total liabilities assumed	627
Net assets acquired	$ 841

(1) None of the goodwill is expected to be deductible for tax purposes.

The fair values of the assets acquired and liabilities assumed is being determined using various valuation techniques, including the income and market approaches.

Regency's Acquisition of Hoover Energy

On February 3, 2014, Regency completed its acquistion of certain subsidiaries of Hoover Energy for a total purchase price of $293 million, consisted of (i) 4.0 million Regency Common Units issued to Hoover Energy, (ii) $184 million in cash. and (iii) $2 million in asset retirement obligations assumed.

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 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, 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 ETP Holdco Interest

On April 30, 2013, ETP acquired ETE's 60% interest in ETP 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 "ETP Holdco Acquisition"). As a result, ETP now owns 100% of ETP 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 ETP 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 ETP 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, Inc. Under the terms of the merger agreement, Sunoco, Inc. shareholders received a total of approximately 55 million ETP Common Units and a total of approximately $2.6 billion in cash.

Sunoco, Inc. 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, Inc. 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, Inc.'s interests in Sunoco Logistics were transferred to ETP.

Prior to the Sunoco Merger, on September 8, 2012, Sunoco, Inc. 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, L.P. ("The Carlyle Group"). Sunoco, Inc. also permanently idled the main refining processing units at its Marcus Hook refinery in June 2012. The Marcus Hook Industrial Complex 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, Inc. retained an approximately 33% non-operating noncontrolling interest. The fair value of Sunoco, Inc.'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, Inc. 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 provides 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, Inc. 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, Inc.'s revenue included in our consolidated statement of operations was approximately $5.93 billion during October through December 2012. Sunoco, Inc.'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.

ETP Holdco Transaction

Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into ETP Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in ETP Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco, Inc. to ETP Holdco and retained a 40% equity interest in ETP Holdco. Prior to the contribution of Sunoco, Inc. to ETP Holdco, Sunoco, Inc. 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 9. Pursuant to a stockholders agreement between ETE and ETP, ETP controlled ETP Holdco (prior to ETP's acquisition of ETE's 60% equity interest in ETP Holdco in 2013) and therefore, ETP consolidated ETP Holdco (including Sunoco, Inc. and Southern Union) in its financial statements subsequent to consummation of the ETP Holdco Transaction.

Under the terms of the ETP 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.

The following table summarizes the assets acquired and liabilities assumed as of the respective acquisition dates:

	Sunoco, Inc.[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.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

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 29.6 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.

Our consolidated financial statements did not reflect the Propane Business as discontinued operations due to ETP's continuing involvement in this business through their 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. 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.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended December 31, 2014, 2013 and 2012 are presented as if Sunoco Merger and the ETP Holdco Transaction had been completed on January 1, 2012, and the PVR and Eagle Rock Midstream acquisitions had been completed on January 1, 2013, and assumes there were no other changes in operations.

	Years Ended December 31,		
	2014	2013	2012
Revenues	$ 56,517	$ 50,473	$ 40,398
Net income	1,098	252	868
Net income attributable to partners	607	133	866
Basic net income per Limited Partner unit	$ 1.12	$ 0.24	$ 1.55
Diluted net income per Limited Partner unit	$ 1.11	$ 0.24	$ 1.55

The pro forma consolidated results of operations include adjustments to:

- include the results of Southern Union and Sunoco, Inc. beginning January 1, 2012;
- include the results of PVR and Eagle Rock midstream beginning January 1, 2013;
- 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 a 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

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. In the year ended 2013, ETP sold 7.5 million AmeriGas common units for net proceeds of $346 million, and in the year ended 2014, ETP sold approximately 18.9 million AmeriGas common units for net proceeds of $814 million. Net proceeds from these sales were used to repay borrowings under the ETP Credit Facility and general partnership purposes. Subsequent to the sales, ETP's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

Citrus

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 $1.82 billion and $1.89 billion at December 31, 2014 and 2013, 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, Inc. 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 $130 million and $144 million as of December 31, 2014 and 2013, 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 $695 million and $548 million as of December 31, 2014 and 2013, 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 $422 million and $442 million as of December 31, 2014 and 2013, 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,	
	2014	2013
Current assets	$ 889	$ 1,028
Property, plant and equipment, net	10,520	10,778
Other assets	2,687	2,664
Total assets	$ 14,096	$ 14,470
Current liabilities	$ 1,983	$ 1,039
Non-current liabilities	7,359	8,139
Equity	4,754	5,292
Total liabilities and equity	$ 14,096	$ 14,470

	Years Ended December 31,		
	2014	2013	2012
Revenue	$ 4,925	$ 4,695	$ 4,492
Operating income	1,071	1,197	863
Net income	577	699	491

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 year ended December 31, 2012 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,		
	2014	2013	2012
Income from continuing operations	$ 1,060	$ 282	$ 1,383
Less: Income from continuing operations attributable to noncontrolling interest	434	99	1,070
Income from continuing operations, net of noncontrolling interest	626	183	313
Less: General Partner's interest in income from continuing operations	2	—	1
Less: Class D Unitholder's interest in income from continuing operations	2	—	—
Income from continuing operations available to Limited Partners	$ 622	$ 183	$ 312
Basic Income from Continuing Operations per Limited Partner Unit:			
Weighted average limited partner units	1,088.6	1,121.8	1,066.9
Basic income from continuing operations per Limited Partner unit	$ 0.58	$ 0.17	$ 0.29
Basic income (loss) from discontinued operations per Limited Partner unit	$ —	$ 0.01	$ —
Diluted Income from Continuing Operations per Limited Partner Unit:			
Income from continuing operations available to Limited Partners	$ 622	$ 183	$ 312
Dilutive effect of equity-based compensation of subsidiaries and distributions to Class D Unitholder	(2)	—	(1)
Diluted income from continuing operations available to Limited Partners	620	183	311
Weighted average limited partner units	1,088.6	1,121.8	1,066.9
Dilutive effect of unconverted unit awards	2.2	—	—
Weighted average limited partner units, assuming dilutive effect of unvested unit awards	1,090.8	1,121.8	1,066.9
Diluted income from continuing operations per Limited Partner unit	$ 0.57	$ 0.17	$ 0.29
Diluted income (loss) from discontinued operations per Limited Partner unit	$ 0.01	$ 0.01	$ —

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2014	2013
Parent Company Indebtedness:		
7.50% Senior Notes, due October 15, 2020	$ 1,187	$ 1,187
5.875% Senior Notes, due January 15, 2024	1,150	450
ETE Senior Secured Term Loan, due December 2, 2019	1,400	1,000
ETE Senior Secured Revolving Credit Facility due December 18, 2018	940	171
Unamortized premiums, discounts and fair value adjustments, net	3	(7)
	4,680	2,801
Subsidiary Indebtedness:		
ETP Debt		
8.5% Senior Notes due April 15, 2014	—	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	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	800
4.9% Senior Notes due February 1, 2024	350	350
7.6% Senior Notes due February 1, 2024	277	277
8.25% Senior Notes due November 15, 2029	267	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	450
5.95% Senior Notes due October 1, 2043	450	450
Floating Rate Junior Subordinated Notes due November 1, 2066	546	546
ETP $2.5 billion Revolving Credit Facility due October 27, 2019	570	65
Unamortized premiums, discounts and fair value adjustments, net	(1)	(34)
	11,459	11,213
Panhandle Debt[(1)]		
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
7.60% Senior Notes due February 1, 2024	82	82
7.00% Senior Notes due July 15, 2029	66	66
8.25% Senior Notes due November 14, 2029	33	33
Floating Rate Junior Subordinated Notes due November 1, 2066	54	54
Unamortized premiums, discounts and fair value adjustments, net	99	155
	1,184	1,240
Regency Debt		
6.875% Senior Notes due December 1, 2018	—	600
5.75% Senior Notes due September 1, 2020	400	400
6.5% Senior Notes due July 15, 2021	500	500
5.875% Senior Notes due March 1, 2022	900	—
5.5% Senior Notes due April 15, 2023	700	700
4.5% Senior Notes due November 1, 2023	600	600

8.375% Senior Notes due June 1, 2020	390	—
6.5% Senior Notes due May 15, 2021	400	—
8.375% Senior Notes due June 1, 2019	499	—
5.0% Senior Notes due October 1, 2022	700	—
Regency $2 billion Revolving Credit Facility due November 25, 2019	1,504	510
Unamortized premiums, discounts and fair value adjustments, net	48	—
	6,641	3,310
Sunoco, Inc. Debt		
4.875% Senior Notes due October 15, 2014	—	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	35	70
	750	1,035
Sunoco Logistics Debt		
8.75% Senior Notes due February 15, 2014[(2)]	—	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	350
4.25% Senior Notes due April 1, 2024	500	—
6.85% Senior Notes due February 1, 2040	250	250
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	350
5.30% Senior Notes due April 1, 2044	700	—
5.35% Senior Notes due May 15, 2045	800	—
Sunoco Logistics $35 million Revolving Credit Facility due April 30, 2015[(3)]	35	35
Sunoco Logistics $1.50 billion Revolving Credit Facility due November 19, 2018	150	200
Unamortized premiums, discounts and fair value adjustments, net	100	118
	4,260	2,503
Sunoco LP Debt		
Sunoco LP $1.25 billion Revolving Credit Facility due September 25, 2019	683	—
	683	—
Transwestern Debt		
5.39% Senior Notes due November 17, 2014	—	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)
	781	869
Other	223	228
	30,661	23,199
Less: current maturities	1,008	637
	$ 29,653	$ 22,562

(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.

(3) The Sunoco Logistics $35 million credit facility outstanding amounts were classified as long-term debt as Sunoco Logistics has the ability and intent to refinance such borrowings on a long-term basis.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $283 million in unamortized premiums and fair value adjustments, net:

2015	$	1,050
2016		314
2017		1,228
2018		2,095
2019		5,662
Thereafter		20,029
Total	$	30,378

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

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.

As discussed above, the Parent Company's outstanding senior notes are collateralized by its interests in certain of its subsidiaries. SEC Rule 3-16 of Regulation S-X ("Rule 3-16") requires a registrant to file financial statements for each of its affiliates whose securities constitute a substantial portion of the collateral for registered securities. The Parent Company's limited partner interests in ETP and Regency constitute substantial portions of the collateral for the Parent Company's outstanding senior notes; accordingly, financial statements of ETP and Regency are required under Rule 3-16 to be included in this Annual Report on Form 10-K and have been included herein.

The Parent Company's interests in ETP GP, ETE Common Holdings, LLC, ETE GP Acquirer LLC, and Regency GP LP (collectively, the "Non-Reporting Entities") also constitute substantial portions of the collateral for the Parent Company's outstanding senior notes. Accordingly, the financial statements of the Non-Reporting Entities would be required under Rule 3-16 to be included in the Parent Company's Annual Report on Form 10-K. None of the Non-Reporting Entities has substantive operations of its own; rather, each of the Non-Reporting Entities holds only direct or indirect interests in ETP, Regency and/or the consolidated subsidiaries of ETP and Regency. Following is a summary of the interests held by each of the Non-Reporting Entities, as well as a summary of the significant differences between each of the Non-Reporting Entities compared to ETP and Regency, as applicable:

- ETP GP owns 100% of the general partner interest in ETP. ETP GP does not own limited partner interests in ETP; therefore, the limited partner interests in ETP, which had a carrying value of $11.9 billion and $11.3 billion as of December 31, 2014 and 2013, respectively, would be reflected as noncontrolling interests on ETP GP's balance sheets. Likewise, ETP's income (loss) attributable to limited partners (including common unitholders and Class H unitholders) of $823 million, $(50) million and $1.11 billion for the years ended December 31, 2014, 2013 and 2012, respectively, would be reflected as income attributable to noncontrolling interest in ETP GP's statements of operations.

- ETE Common Holdings, LLC ("ETE Common Holdings") owns 5.2 million ETP Common Units, representing approximately 1.5% of the total outstanding ETP Common Units, and 50.2 million ETP Class H Units, representing 100% of the total outstanding ETP Class H Units. ETE Common Holdings also owns 30.9 million Regency Common

Units, representing approximately 7.5% of the total outstanding Regency Common Units; ETE Common Holdings' interest in Regency was acquired in 2014. ETE Common Holdings does not own the general partner interests in ETP or Regency; therefore, the financial statements of ETE Common Holdings would only reflect equity method investments in ETP and Regency. The carrying values of ETE Common Holdings' investments in ETP and Regency were $1.72 billion and $760 million, respectively, as of December 31, 2014 and $1.66 billion and zero, respectively, as of December 31, 2013. ETE Common Holdings' equity in earnings (losses) from its investments in ETP and Regency were $292 million and $(9) million, respectively, for the year ended December 31, 2014 and $134 million and zero, respectively, for the period from April 26, 2013 (inception of ETE Common Holdings) to December 31, 2013.

- ETE GP Acquirer LLC ("ETE GP Acquirer") owns 100% of Regency GP, which owns 100% of the general partner interest in Regency. Neither ETE GP Acquirer nor Regency GP own limited partner interests in Regency; therefore, the limited partner interests in Regency, which had a carrying value of $8.7 billion and $4.0 billion as of December 31, 2014 and 2013, respectively, would be reflected as noncontrolling interests on ETE GP Acquirer's and Regency GP's balance sheets. Likewise, Regency's income (loss) attributable to limited partners and preferred unitholders, which totaled $(188) million, $8 million and $23 million for the years ended December 31, 2014, 3013 and 2012, respectively, would be reflected as income attributable to noncontrolling interest in ETE GP Acquirer's and Regency GP's statements of operations.

ETP's general partner interest, Common Units and Class H Units are reflected separately in ETP's financial statements, and Regency's general partner interest and Common Units are reflected separately in Regency's financial statements. As a result, the financial statements of the Non-Reporting Entities would substantially duplicate information that is available in the financial statements of ETP and Regency. Therefore, the financial statements of the Non-Reporting Entities have been excluded from this Annual Report on Form 10-K.

ETP as Co-Obligor of Sunoco, Inc. Debt

In connection with the Sunoco Merger and ETP Holdco Transaction, ETP became a co-obligor on approximately $965 million of aggregate principal amount of Sunoco, Inc.'s existing senior notes and debentures. The balance of these notes was $715 million as of December 31, 2014.

Panhandle Junior Subordinated Notes

The interest rate on the remaining portion of Panhandle's 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 $54 million at an effective interest rate of 3.26% at December 31, 2014.

ETP Senior Notes

The ETP senior notes were registered under the Securities Act of 1933 (as amended). ETP 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 ETP and the obligation of ETP to repay the ETP senior notes is not guaranteed by us or any of ETP'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 payable semi-annually.

Sunoco Logistics Senior Notes Offerings

In April 2014, Sunoco Logistics issued $300 million aggregate principal amount of 4.25% senior notes due April 2024 and $700 million aggregate principal amount of 5.30% senior notes due April 2044.

In November 2014, Sunoco Logistics issued an additional $200 million under the April 2024 senior notes and $800 million aggregate principal amount of 5.35% senior notes due May 2045. Sunoco Logistics used the net proceeds from the offerings to pay borrowings under the Sunoco Logistics Credit Facility and for general partnership purposes.

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.

In February 2014, Regency issued $900 million aggregate principal amount of 5.875% senior notes due March 1, 2022.

In March 2014, as part of the PVR Acquisition, Regency assumed the outstanding senior notes of PVR with an aggregate notional amount of $1.2 billion. The PVR senior notes consisted of $300 million principal amount of 8.25% senior notes due April 15, 2018, $400 million principal amount of 6.5% senior notes due May 15, 2021, and $473 million principal amount of 8.375% senior notes due June 1, 2020. In April 2014, Regency redeemed all of the $300 million principal amount of 8.25% senior notes due April 15, 2018 for $313 million in cash. In July 2014, Regency redeemed $83 million of the $473 million principal amount of 8.375% senior notes due June 1, 2020 for $91 million, including $8 million of accrued interest and redemption premium.

In July 2014, Regency exchanged $499 million aggregate principal amount of 8.375% senior notes due 2019 of Eagle Rock and Eagle Rock Energy Finance Corp. for 8.375% senior notes due 2019 issued by Regency and its wholly-owned subsidiary.

In July 2014, Regency issued $700 million aggregate principal amount of 5.0% senior notes that mature on October 1, 2022.

In December 2014, Regency redeemed all of the outstanding $600 million senior notes due 2018, for a total price of $621 million.

Term Loans and Credit Facilities

ETE Term Loan Facility

The Parent Company has 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%.

In April 2014, the Parent Company amended its Senior Secured Term Loan Agreement (the "ETE Term Credit Agreement") to increase the aggregate principal amount to $1.4 billion. The Parent Company used the proceeds from this $400 million increase to repay borrowings under its revolving credit facility and for general partnership purposes. No other significant changes were made to the terms of the ETE Term Credit Agreement, including maturity date and interest rate.

ETE Revolving Credit Facility

The Parent Company has 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. In May 2014, the Parent Company amended its revolving credit facility to increase the capacity to $1.2 billion. In February 2015, the Parent Company amended its revolving credit facility to increase the capacity to $1.5 billion.

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 2019. 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 ETP's growth projects, as well as for general partnership purposes. In February 2015, ETP amended its revolving credit facility to increase the capacity to $3.75 billion.

As of December 31, 2014, the ETP Credit Facility had $570 million outstanding, and the amount available for future borrowings was $1.81 billion after taking into account letters of credit of $121 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 was 1.66%.

Regency Credit Facility

The Regency Credit Facility has aggregate revolving commitments of $2.0 billion, with a $500 million incremental facility. The maturity date of the Regency Credit Facility is November 25, 2019.

As of December 31, 2014, Regency had a balance of $1.50 billion outstanding under the Regency Credit Facility in revolving credit loans and approximately $23 million in letters of credit. The total amount available under the Regency Credit Facility, as of December 31, 2014, which is reduced by any letters of credit, was approximately $473 million. The weighted average interest rate on the total amount outstanding as of December 31, 2014 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.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $1.50 billion unsecured credit facility (the "Sunoco Logistics Credit Facility") which matures in November 2018. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $2.25 billion under certain conditions.

The Sunoco Logistics Credit Facility is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The Sunoco Logistics Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. As of December 31, 2014, the Sunoco Logistics Credit Facility had $150 million of outstanding borrowings.

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. At December 31, 2014, this credit facility had $35 million of outstanding borrowings.

Sunoco LP Credit Facility

In September 2014, Sunoco LP entered into a $1.25 billion revolving credit agreement (the "Sunoco LP Credit Facility"), which matures in September 2019. The Sunoco LP Credit Facility can be increased from time to time upon Sunoco LP's written request, subject to certain conditions, up to an additional $250 million. As of December 31, 2014, the Sunoco LP Credit Facility had $683 million of outstanding borrowings.

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 these covenants except that the lien covenant will continue to be applicable. ETP has advised Regency that it intends to provide an ETP guarantee with respect to the outstanding Regency senior notes upon the closing of the Regency Merger, and it is expected that this will result in the Regency senior notes being upgraded an investment grade rating by both Moody's and SAP.

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 Panhandle

Panhandle 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 Panhandle's lending agreements. Financial covenants exist in certain of Panhandle's debt agreements that require Panhandle 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 Panhandle 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 Panhandle did not cure such default within any permitted cure period or if Panhandle did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Panhandle'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 Panhandle's debt and other financial obligations and that of its subsidiaries.

In addition, Panhandle 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 Panhandle's cash management program; and limitations on Panhandle'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 3.7 to 1 at December 31, 2014, as calculated in accordance with the credit agreements.

The West Texas Gulf Pipeline Company's $35 million credit facility limits West Texas Gulf, on a rolling four-quarter basis, to a minimum fixed charge coverage ratio of 1.00 to 1. 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 1.67 to 1 and 0.85 to 1, respectively, at December 31, 2014.

Covenants Related to Sunoco LP

The Sunoco LP Credit Facility requires Sunoco LP to maintain a leverage ratio of not more than 5.50 to 1. The maximum leverage ratio is subject to upwards adjustment of not more than 6.00 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in an acquisition of assets, equity interests, operating lines or divisions by Sunoco LP, a subsidiary, an unrestricted subsidiary or a joint venture for a purchase price of not less than $50 million. Indebtedness under the Sunoco LP Credit Facility is secured by a security interest in, among other things, all of the Sunoco LP's present and future personal property and all of the present and future personal property of its guarantors, the capital stock of its material subsidiaries (or 66% of the capital stock of material foreign subsidiaries), and any intercompany debt. Upon the first achievement by Sunoco LP of an investment grade credit rating, all security interests securing the Sunoco LP Credit Facility will be released.

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, 2014.

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. 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.

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, 2014, the remaining Regency Preferred Units were convertible into 2,064,805 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, January 1, 2013	4.4	$ 73	
Regency Preferred Units converted into Regency Common Units	(2.5)	(41)	
Balance, December 31, 2013	1.9	$ 32	(1)
Accretion to redemption value	N/A	1	
Balance, December 31, 2014	1.9	33	

(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. REDEEMABLE NONCONTROLLING INTERESTS:

The noncontrolling interest holders in one of Sunoco Logistics' consolidated subsidiaries have the option to sell their interests to Sunoco Logistics. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable interest on our consolidated balance sheet.

9. 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, 2014, there were issued and outstanding 1.08 billion Common Units representing an aggregate 99.46% 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, 2014, 2013 and 2012 was as follows:

	Years Ended December 31,		
	2014	2013	2012
Number of Common Units, beginning of period	1,119.8	1,119.8	891.9
Repurchase of common units under buyback program	(42.3)	—	—
Issuance of common units in connection with Southern Union Merger (See Note 3)	—	—	227.9
Number of Common Units, end of period	1,077.5	1,119.8	1,119.8

Common Unit Splits

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.

On May 28, 2015, 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 July 27, 2015. 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 July 15, 2015.

Repurchase Program

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 42.3 million ETE Common Units under this program through May 23, 2014, and the program was completed.

In February 2015, the Partnership announced a common unit repurchase program, whereby the Partnership may repurchase up to $2 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.

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 3,000,000 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 3,000,000 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 3,080,000 Class D Units of ETE, which number of Class D Units includes an additional 80,000 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 subsidiaries and the underlying book value arising from issuance of units by subsidiaries (excluding unit issuances to the Parent Company) as a capital transaction. If a subsidiary 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 issuances of subsidiary 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
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, 2014, ETP issued approximately 2.7 million units for $144 million, net of commissions of $2 million. No amounts of ETP Common Units remain available to be issued under the January 2013 and May 2013 equity distribution agreements.

In May 2014 and November 2014, 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 $1.0 billion and $1.50 billion, respectively. During the year ended December 31, 2014, ETP issued approximately 18.8 million units for $1.08 billion, net of commissions of $11 million. As of December 31, 2014, approximately $1.41 billion of ETP Common Units remained available to be issued under ETP's currently effective equity distribution agreements.

ETP's Equity Incentive Plan Activity

As discussed in Note 10, 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

ETP's Distribution Reinvestment Plan (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.

During the years ended December 31, 2014, 2013 and 2012, aggregate distributions of approximately $155 million, $109 million and $43 million, respectively, were reinvested under the DRIP resulting in the issuance in aggregate of approximately 6.1 million ETP Common Units.

As of December 31, 2014, a total of 7.3 million ETP Common Units remain available to be issued under the existing registration statement.

ETP Class E 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 ETP 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. All of the 8.9 million ETP Class E Units outstanding are held by a subsidiary of ETP and therefore are reflected by ETP as treasury units in its consolidated financial statements.

ETP Class G Units

In conjunction with the Sunoco Merger, ETP amended its partnership agreement to create 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, Inc. 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 ETP 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 and Class I Units

Currently Outstanding

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.

Pending Transaction

In December 2014, ETP and ETE announced the final terms of a transaction, whereby ETE will transfer 30.8 million ETP Common Units, ETE’s 45% interest in the Bakken pipeline project, and $879 million in cash in exchange for 30.8 million newly issued ETP Class H Units that, when combined with the 50.2 million previously issued ETP Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics (the “Bakken Pipeline Transaction”). In connection with this transaction, ETP will also issue 100 ETP Class I Units, as described below. In addition, ETE and ETP agreed to reduce the IDR subsidies that ETE previously agreed to provide to ETP, with such reductions occurring in 2015 and 2016.

In connection with the transaction, ETP will also issue 100 ETP Class I Units. The ETP Class I Units are generally entitled to: (i) pro rata allocations of gross income or gain until the aggregate amount of such items allocated to the holders of the ETP Class I Units for the current taxable period and all previous taxable periods is equal to the cumulative amount of all distributions made to the holders of the ETP Class I Units and (ii) after making cash distributions to ETP Class H Units, any additional available cash deemed to be either operating surplus or capital surplus with respect to any quarter will be distributed to the ETP Class I Units in an amount equal to the excess of the distribution amount set forth in the ETP Partnership Agreement, as amended, (the “Partnership Agreement”) for such quarter over the cumulative amount of available cash previously distributed commencing with the quarter ending March 31, 2015 until the quarter ending December 31, 2016. The impact of (i) the IDR subsidy adjustments and (ii) the Class I Unit distributions, along with the currently effective IDR subsidies, is included in the table below under “ETP Quarterly Distributions of Available Cash” in the column titled “Pro Forma for ETP Class H and Class I Units.”

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	Price per Regency Unit	Net Proceeds
March 2012	12.7	$ 24.47	$ 297

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.

Regency issued 4.0 million, 140.4 million and 8.2 million Regency Common Units in connection with the Hoover, PVR and Eagle Rock Midstream acquisitions, respectively.

In June 2014, Regency sold 14.4 million Regency Common Units to a wholly-owned subsidiary of ETE for approximately $400 million. Proceeds from the issuance were used to pay down borrowings on the Regency Credit Facility, to redeem certain Regency senior notes and for general partnership purposes. In July 2014, Regency sold an additional 16.5 million Regency Common Units to a wholly-owned subsidiary of ETE in connection with the Eagle Rock Midstream Acquisition for approximately $400 million. Proceeds from the issuance were used to fund a portion of the cash consideration paid to Eagle Rock in connection with the Eagle Rock Midstream Acquisition.

Regency's Equity Distribution Program

From time to time, Regency has sold Regency Common Units through an equity distribution agreement. Such sales of Regency 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 June 2012, Regency entered into an equity distribution agreement with Citigroup Global Markets Inc. 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. For the years ended December 31, 2014 and 2013, Regency received net proceeds of $34 million and $149 million, respectively, from Regency Common Units issued pursuant to this equity distribution agreement. No amounts remain available to be issued under this agreement and it is no longer effective.

In May 2014, Regency entered into an equity distribution agreement with a group of banks and investment companies under which Regency may offer and sell Regency Common Units, representing limited partner interests, for an aggregate offering price of up to $400 million, from time to time through this group of institutions, as sales agent for Regency. For the year ended December 31, 2014, Regency received net proceeds of $395 million from Regency Common Units issued pursuant to this equity distribution agreement. No amounts remained available to be issued under this agreement and it is no longer effective.

In January 2015, Regency entered into an equity distribution agreement with a group of banks and investment companies (the "Managers") under which Regency may offer and sell Regency Common Units for an aggregate offering price of up to $1 billion, from time to time through the Managers, as sales agent for Regency. Regency intends to use the net proceeds from the sale of Regency Common Units for general partnership purposes.

Sales of Common Units by Sunoco Logistics

In 2014, Sunoco Logistics entered into equity distribution agreements pursuant to which Sunoco Logistics may sell from time to time common units having aggregate offering prices of up to $1.25 billion. During the year ended December 31, 2014, Sunoco Logistics received proceeds of $477 million, net of commissions of $5 million, from the issuance of 10.3 million common units pursuant to the equity distribution agreement, which were used for general partnership purposes.

Additionally, Sunoco Logistics completed an overnight public offering of 7.7 million common units for net proceeds of $362 million in September 2014. The net proceeds from this offering were used to repay outstanding borrowings under the $1.50 billion Sunoco Logistics Credit Facility and for general partnership purposes.

Sales of Common Units by Sunoco LP

In October 2014 and November 2014, Sunoco LP issued an aggregate total of 9.1 million common units in an underwritten public offering. Aggregate net proceeds of $405 million from the offering were used to repay amounts outstanding under the $1.25 billion Sunoco LP Credit Facility and for general partnership purposes.

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 well as cash generated from our investment in Lake Charles LNG.

Our distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2011	February 7, 2012	February 17, 2012	$ 0.1563
March 31, 2012	May 4, 2012	May 18, 2012	0.1563
June 30, 2012	August 6, 2012	August 17, 2012	0.1563
September 30, 2012	November 6, 2012	November 16, 2012	0.1563
December 31, 2012	February 7, 2013	February 19, 2013	0.1588
March 31, 2013	May 6, 2013	May 17, 2013	0.1613
June 30, 2013	August 5, 2013	August 19, 2013	0.1638
September 30, 2013	November 4, 2013	November 19, 2013	0.1681
December 31, 2013	February 7, 2014	February 19, 2014	0.1731
March 31, 2014	May 5, 2014	May 19, 2014	0.1794
June 30, 2014	August 4, 2014	August 19, 2014	0.1900
September 30, 2014	November 3, 2014	November 19, 2014	0.2075
December 31, 2014	February 6, 2015	February 19, 2015	0.2250

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 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 were as follows:

Quarter Ended	Record Date	Payment Date	Distribution per ETP Common Unit
December 31, 2011	February 7, 2012	February 14, 2012	$ 0.8938
March 31, 2012	May 4, 2012	May 15, 2012	0.8938
June 30, 2012	August 6, 2012	August 14, 2012	0.8938
September 30, 2012	November 6, 2012	November 14, 2012	0.8938
December 31, 2012	February 7, 2013	February 14, 2013	0.8938
March 31, 2013	May 6, 2013	May 15, 2013	0.8938
June 30, 2013	August 5, 2013	August 14, 2013	0.8938
September 30, 2013	November 4, 2013	November 14, 2013	0.9050
December 31, 2013	February 7, 2014	February 14, 2014	0.9200
March 31, 2014	May 5, 2014	May 15, 2014	0.9350
June 30, 2014	August 4, 2014	August 14, 2014	0.9550
September 30, 2014	November 3, 2014	November 14, 2014	0.9750
December 31, 2014	February 6, 2015	February 13, 2015	0.9950

In connection with transactions between ETP and ETE, ETE has agreed to relinquish its right to certain incentive distributions in future periods. Following is a summary of the net reduction in total distributions that would potentially be made to ETE in future periods based on (i) the currently effective partnership agreement provisions, (ii) the assumed closing of the issuance of additional ETP Class H Units and ETP Class I Units, which is expected to occur in March 2015, and (iii) the assumed closing of the Regency Merger, which is expected to occur in the second quarter of 2015:

Years Ending December 31,	Currently Effective	Pro Forma for ETP Class H and Class I Units(1)	Pro Forma for Regency Merger(2)
2015	$ 86	$ 31	$ 91
2016	107	77	142
2017	85	85	145
2018	80	80	140
2019	70	70	130
2020	35	35	50
2021	35	35	35
2022	35	35	35
2023	35	35	35
2024	18	18	18

(1) Pro forma amounts reflect the IDR subsidies, as adjusted for the pending issuance of additional ETP Class H Units and ETP Class I Units discussed above, as well as distributions on the ETP Class I Units. The issuance of additional ETP Class H Units and ETP Class I Units is expected to close in March 2015.

(2) Pro forma amounts reflect the IDR subsidies, as adjusted for (i) the pending issuance of additional ETP Class H Units and ETP Class I Units (as described in Note (1) above) and (ii) the pending Regency Merger. Amounts reflected above assume that the Regency Merger is closed subsequent to the record date for the first quarter of 2015 distribution payment and prior to the record date for the second quarter 2015 distribution payment.

The amounts reflected above include the relinquishment of $350 million in the aggregate of incentive distributions that would potentially be made to ETE over the first forty fiscal quarters commencing immediately after the consummation of the Susser Merger. Such relinquishments would cease upon the agreement of an exchange of the Sunoco LP general partner interest and the incentive distribution rights between ETE and ETP.

Regency's Quarterly Distributions 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 declared by Regency during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Distribution per Regency Common Unit
December 31, 2011	February 6, 2012	February 13, 2012	$ 0.4600
March 31, 2012	May 7, 2012	May 14, 2012	0.4600
June 30, 2012	August 6, 2012	August 14, 2012	0.4600
September 30, 2012	November 6, 2012	November 14, 2012	0.4600
December 31, 2012	February 7, 2013	February 14, 2013	0.4600
March 31, 2013	May 6, 2013	May 13, 2013	0.4600
June 30, 2013	August 5, 2013	August 14, 2013	0.4650
September 30, 2013	November 4, 2013	November 14, 2013	0.4700
December 31, 2013	February 7, 2014	February 14, 2014	0.4750
March 31, 2014	May 8, 2014	May 15, 2014	0.4800
June 30, 2014	August 7, 2014	August 14, 2014	0.4900
September 30, 2014	November 4, 2014	November 14, 2014	0.5025
December 31, 2014	February 6, 2015	February 13, 2015	0.5025

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 declared by Sunoco Logistics during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Distribution per Sunoco Logistics Common Unit
December 31, 2012	February 8, 2013	February 14, 2013	$ 0.2725
March 31, 2013	May 9, 2013	May 15, 2013	0.2863
June 30, 2013	August 8, 2013	August 14, 2013	0.3000
September 30, 2013	November 8, 2013	November 14, 2013	0.3150
December 31, 2013	February 10, 2014	February 14, 2014	0.3312
March 31, 2014	May 9, 2014	May 15, 2014	0.3475
June 30, 2014	August 8, 2014	August 14, 2014	0.3650
September 30, 2014	November 7, 2014	November 14, 2014	0.3825
December 31, 2014	February 9, 2015	February 13, 2015	0.4000

Sunoco Logistics Unit Split

On May 5, 2014, Sunoco Logistics' board of directors declared a two-for-one split of Sunoco Logistics common units. The unit split resulted in the issuance of one additional Sunoco Logistics common unit for every one unit owned as of the close of business on June 5, 2014. The unit split was effective June 12, 2014. All Sunoco Logistics unit and per unit information included in this report is presented on a post-split basis.

Sunoco LP Quarterly Distributions of Available Cash

Distributions declared by Sunoco LP subsequent to our acquisition on August 29, 2014 were as follows:

Quarter Ended	Record Date	Payment Date	Distribution per Sunoco LP Common Unit
September 30, 2014	November 18, 2014	November 28, 2014	$ 0.5457
December 31, 2014	February 17, 2015	February 27, 2015	0.6000

Accumulated Other Comprehensive Income (Loss)

The following table presents the components of AOCI, net of tax:

	December 31, 2014	December 31, 2013
Available-for-sale securities	$ 3	$ 2
Foreign currency translation adjustment	(3)	(1)
Net losses on commodity related hedges	(1)	(4)
Actuarial gain (loss) related to pensions and other postretirement benefits	(57)	56
Investments in unconsolidated affiliates, net	2	8
Subtotal	(56)	61
Amounts attributable to noncontrolling interest	51	(52)
Total AOCI included in partners' capital, net of tax	$ (5)	$ 9

The table below sets forth the tax amounts included in the respective components of other comprehensive income (loss):

	December 31, 2014	December 31, 2013
Available-for-sale securities	$ (1)	$ (1)
Foreign currency translation adjustment	2	1
Actuarial gain relating to pension and other postretirement benefits	(37)	(39)
Total	$ (36)	$ (39)

10. 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, cash restricted units 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 12,000,000 units. As of December 31, 2014, 11,380,202 units remain available to be awarded under the plan.

In December 2013, 3,080,000 Class D Units were granted to an ETE employee, Jamie 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 9 to our consolidated financial statements.

During 2014, no awards were granted to ETE employees and 7,374 ETE units were granted to non-employee directors. Under our equity incentive plans, our non-employee directors each receive grants that vest 60% in three years and 40% in five years and do not entitle the holders to receive distributions during the vesting period.

During 2014, a total of 60,068 ETE Common Units vested, with a total fair value of $1.5 million as of the vesting date. As of December 31, 2014, excluding Class D units, a total of 68,680 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 2.1 years. As of December 31, 2014, a total of 3,080,000 Class D Units granted to Mr. Welch remain outstanding, for which we expect to recognize a total of $23 million in compensation over a weighted average period of 3.0 years.

ETP Unit-Based Compensation Plans

Restricted Units

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.

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, 2013	3.2	$ 49.65
Awards granted	1.0	60.85
Awards vested	(0.5)	48.12
Awards forfeited	(0.1)	32.36
Unvested awards as of December 31, 2014	3.6	53.83

During the years ended December 31, 2014, 2013 and 2012, the weighted average grant-date fair value per unit award granted was $60.85, $50.54 and $43.93, respectively. The total fair value of awards vested was $26 million, $29 million and $29 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2014, a total of 3.6 million unit awards remain unvested, for which ETP expects to recognize a total of $128 million in compensation expense over a weighted average period of 2.0 years.

Cash Restricted Units

ETP has also granted cash restricted units, which vest 100% at the end of the third year of service. A cash restricted unit entitles the award recipient to receive cash equal to the market value of one ETP Common Unit upon vesting.

As of December 31, 2014, a total of 0.4 million unvested cash restricted units units were outstanding.

Based on the trading price of ETP Common Units at December 31, 2014, ETP expects to recognize $24 million of unit-based compensation expense related to non-vested cash restricted units over a period of 1.8 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 0.7 million Sunoco, Inc. common units. As of December 31, 2014, a total of 1.5 million Sunoco Logistics restricted units were outstanding for which Sunoco Logistics expects to recognize $33 million of expense over a weighted-average period of 2.9 years.

Regency Unit-Based Compensation Plans

Regency had the following awards outstanding as of December 31, 2014:

- 107,650 Regency Common Unit options, all of which are exercisable, with a weighted average exercise price of $22.68 per unit option; and
- 2,167,719 Regency Phantom Units, with a weighted average grant date fair value of $24.31 per Phantom Unit.

Regency expects to recognize $42 million of compensation expense related to the Regency Phantom Units over a period of 3.9 years.

Cash Restricted Units

Regency began granting cash restricted units in 2014. These awards are service condition (time-based) grants which vest 100% at the end of the third year of service. A cash restricted unit entitles the award recipient to receive cash equal to the market value of one Regency Common Unit upon vesting. Regency had 379,328 cash restricted units outstanding at December 31, 2014.

Based on the trading price of Regency Common Units at December 31, 2014, Regency expects to recognize $7 million of unit-based compensation expense related to non-vested cash restricted units over a period of 2.5 years.

11. 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,		
	2014	2013	2012
Current expense (benefit):			
Federal	$ 321	$ 51	$ (3)
State	86	(1)	6
Total	407	50	3
Deferred expense (benefit):			
Federal	(53)	(14)	41
State	3	57	10
Total	(50)	43	51
Total income tax expense from continuing operations	$ 357	$ 93	$ 54

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 Merger, Sunoco Merger, ETP Holdco Transaction and the Susser Merger (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, 2014 and 2013 is as follows:

	December 31, 2014			December 31, 2013		
	Corporate Subsidiaries[1]	Partnership[2]	Consolidated	Corporate Subsidiaries[1]	Partnership[2]	Consolidated
Income tax expense (benefit) at U.S. statutory rate of 35 percent	$ 212	$ —	$ 212	$ (172)	$ —	$ (172)
Increase (reduction) in income taxes resulting from:						
Nondeductible goodwill	—	—	—	241	—	241
Nondeductible goodwill included in the Lake Charles LNG Transaction	105	—	105	—	—	—
Premium on debt retirement	(10)	—	(10)	—	—	—
Foreign taxes	(8)	—	(8)	—	—	—
State income taxes (net of federal income tax effects)	9	46	55	31	10	41
Other	3	—	3	(16)	(1)	(17)
Income tax from continuing operations	$ 311	$ 46	$ 357	$ 84	$ 9	$ 93

(1) Includes ETP Holdco, Susser, Oasis Pipeline Company, Susser Petroleum Property Company LLC, Aloha Petroleum Ltd, Pueblo, Inland Corporation, Mid-Valley Pipeline Company and West Texas Gulf Pipeline Company. ETP Holdco, which was formed via the Sunoco Merger and the ETP Holdco Transaction (see Note 3), includes Sunoco, Inc. and Panhandle. ETE held a 60% interest in ETP Holdco until April 30, 2013. Subsequent to the ETP Holdco Acquisition (see Note 3) on April 30, 2013, ETP owns 100% of ETP Holdco.

(2) Includes ETE and its respective subsidiaries that are classified as pass-through entities for federal income tax purposes.

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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,	
	2014	2013
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$ 116	$ 217
Pension and other postretirement benefits	47	57
Long term debt	53	108
Other	111	104
Total deferred income tax assets	327	486
Valuation allowance	(84)	(74)
Net deferred income tax assets	243	412
Deferred income tax liabilities:		
Properties, plants and equipment	(1,583)	(1,624)
Inventory	(153)	(302)
Investments in unconsolidated affiliates	(2,530)	(2,245)
Trademarks	(355)	(180)
Other	(32)	(45)
Total deferred income tax liabilities	(4,653)	(4,396)
Net deferred income tax liability	(4,410)	(3,984)
Less: current portion of deferred income tax liabilities, net	(85)	(119)
Accumulated deferred income taxes	$ (4,325)	$ (3,865)

The completion of the Southern Union Merger, Sunoco Merger, ETP Holdco Transaction and Susser Merger (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,	
	2014	2013
Net deferred income tax liability, beginning of year	$ (3,984)	$ (3,696)
Susser acquisition	(488)	—
SUGS Contribution to Regency	—	(115)
Tax provision (including discontinued operations)	62	(124)
Other	—	(49)
Net deferred income tax liability	$ (4,410)	$ (3,984)

ETP Holdco, Susser and other corporate subsidiaries have gross federal net operating loss carryforwards of $5 million, all of which will expire in 2032 and 2033. Our corporate subsidiaries had less than $1 million of federal alternative minimum tax credits at December 31, 2014. Our corporate subsidiaries have state net operating loss carryforward benefits of $111 million, net of federal tax, which expire between 2014 and 2033. The valuation allowance of $84 million is applicable to the state net operating loss carryforward benefits applicable to Sunoco, Inc. pre-acquisition periods.

The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31,		
	2014	2013	2012
Balance at beginning of year	$ 429	$ 27	$ 2
Additions attributable to acquisitions	—	—	28
Additions attributable to tax positions taken in the current year	20	—	—
Additions attributable to tax positions taken in prior years	(1)	406	—
Settlements	(5)	—	—
Lapse of statute	(3)	(4)	(3)
Balance at end of year	$ 440	$ 429	$ 27

As of December 31, 2014, we have $439 million ($425 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 $4 million ($2 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Sunoco, Inc. has historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco, Inc.'s 2004 through 2011 open statute years, Sunoco, Inc. has proposed to the IRS that these government incentive payments be excluded from federal taxable income. If Sunoco, Inc. 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, 2014.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2014, we recognized interest and penalties of less than $1 million. At December 31, 2014, 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 Internal Revenue Service ("IRS") for 2010 and prior tax years. However, Sunoco, Inc. and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2007, and Southern Union and its subsidiaries are no longer subject to examination by the IRS for tax years prior to and 2004. Regency and its subsidiaries are no longer subject to examination by the IRS for tax years prior to 2007.

Sunoco, Inc. has been examined by the IRS for tax years through 2012. However, the statutes remain open for tax years 2007 and forward due to carryback of net operating losses and/or claims regarding government incentive payments discussed above. All other issues are resolved. Though we believe the tax years are closed by statue, tax years 2004 through 2006 are impacted by the carryback of net operating losses and under certain circumstances may be impacted by adjustments for government incentive payments. Southern Union is under examination for the tax years 2004 through 2009. As of December 31, 2014, 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 have vigorously defended this tax position and believe we have reached a tentative settlement with the IRS which will not have a material impact on our consolidated financial position or results of operations. 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.

12. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

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 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

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 Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992. Under the ICA, tariff rates must be just and reasonable and not unduly discriminatory and pipelines may not 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.

Transwestern Rate Case

On October 1, 2014, Transwestern filed a general NGA Section 4 rate case pursuant to the 2011 settlement agreement with its shippers. On December 2, 2014, the FERC issued an order accepting and suspending the rates to be effective April 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in August 2015.

FGT Rate Case

On October 31, 2014, FGT filed a general NGA Section 4 rate case pursuant to a 2010 settlement agreement with its shippers. On November 28, 2014, the FERC issued an order accepting and suspending the rates to be effective May 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in late 2015.

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 2058. The table below reflects rental expense under these operating leases included in operating expenses in the accompanying statements of operations, which include contingent rentals, and rental expense recovered through related sublease rental income:

	Years Ended December 31,		
	2014	2013	2012
Rental expense[1]	$ 159	$ 151	$ 60
Less: Sublease rental income	(26)	(24)	(4)
Rental expense, net	$ 133	$ 127	$ 56

(1) Includes contingent rentals totaling $24 million, $22 million and $6 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Future minimum lease commitments for such leases are:

Years Ending December 31:	
2015	$ 151
2016	129
2017	118
2018	108
2019	102
Thereafter	829
Future minimum lease commitments	1,437
Less: Sublease rental income	(34)
Net future minimum lease commitments	$ 1,403

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 oil 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.

MTBE Litigation

Sunoco, Inc., 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, 2014, Sunoco, Inc. is a defendant in five cases, including cases initiated by the States of New Jersey, Vermont, the Commonwealth of Pennsylvania, 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. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court. The New Jersey, Puerto Rico, Vermont and Pennsylvania cases assert natural resource damage claims.

Fact discovery has concluded with respect to an initial set of 19 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, Inc. in these matters. It is reasonably possible that a loss may be realized; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. 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.

Eagle Rock Shareholder Litigation

Three putative class action lawsuits challenging the Eagle Rock Midstream Acquisition are currently pending in federal district court in Houston, Texas. All cases name Eagle Rock and its current directors, as well as the Partnership and a subsidiary, as defendants. One of the lawsuits also names additional Eagle Rock entities as defendants. Each of the lawsuits has been brought by a purported unitholder of Eagle Rock (collectively, the "Plaintiffs"), both individually and on behalf of a putative class consisting of public unitholders of Eagle Rock. The Plaintiffs in each case seek to rescind the transaction, claiming, among other things, that it yields inadequate consideration, was tainted by conflict and constitutes breaches of common law fiduciary duties or contractually imposed duties to the shareholders. Plaintiffs also seek monetary damages and attorneys' fees. Regency and its subsidiary are named as "aiders and abettors" of the allegedly wrongful actions of Eagle Rock and its board.

Enterprise Products Partners, L.P. and Enterprise Products Operating LLC Litigation

On January 27, 2014, a trial commenced between ETP against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETP against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETP. The jury also found that ETP owed Enterprise $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETP and awarded ETP $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETP shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise has filed a notice of appeal. In accordance with GAAP, no amounts related to the original verdict or the July 29, 2014 final judgment will be recorded in our financial statements until the appeal process is completed.

Other Litigation and Contingencies

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, 2014 and 2013, accruals of approximately $37 million and $46 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 resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued.

No amounts have been recorded in our December 31, 2014 or 2013 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

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 Massachusetts Department of Public Utilities (“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. Panhandle (as successor to Southern Union) believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, Panhandle 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.
- Currently operating Sunoco, Inc. retail sites.
- Legacy sites related to Sunoco, Inc., that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco, Inc. 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, 2014, Sunoco, Inc. had been named as a PRP at approximately 51 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.’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. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. 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,	
	2014	2013
Current	$ 41	$ 47
Non-current	360	356
Total environmental liabilities	$ 401	$ 403

In 2013, we 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, 2014 and 2013, the Partnership recorded $48 million and $41 million, respectively, of expenditures related to environmental cleanup programs.

On June 29, 2011, the U.S. Environmental Protection Agency finalized a rule under the Clean Air Act 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 U.S. Department of Transportation 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.

13. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

ETP

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 operating entity.

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 ETP's 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 ETP recognizes 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 liquids 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 also uses derivatives to hedge a variety of price risks in its retail marketing operations. Futures and swaps are used to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales and transportation costs. The derivatives used in ETP's retail marketing operations represent economic hedges; however, ETP has elected not to designate any of the hedges in these operations. 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 its risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in ETP's commodity risk management policy.

The following table details ETP's outstanding commodity-related derivatives:

	December 31, 2014		December 31, 2013	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	(232,500)	2015	9,457,500	2014-2019
Basis Swaps IFERC/NYMEX [(1)]	(13,907,500)	2015 - 2016	(487,500)	2014-2017
Swing Swaps	—	—	1,937,500	2014-2016
Options – Calls	5,000,000	2015	—	—
Power (Megawatt):				
Forwards	288,775	2015	351,050	2014
Futures	(156,000)	2015	(772,476)	2014
Options — Puts	(72,000)	2015	(52,800)	2014
Options — Calls	198,556	2015	103,200	2014
Crude (Bbls) – Futures	—	—	103,000	2014
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	57,500	2015	570,000	2014
Swing Swaps IFERC	46,150,000	2015	(9,690,000)	2014-2016
Fixed Swaps/Futures	(8,779,000)	2015 - 2016	(8,195,000)	2014-2015
Forward Physical Contracts	(9,116,777)	2015	5,668,559	2014-2015
Natural Gas Liquid (Bbls) – Forwards/Swaps	(2,179,400)	2015	(1,133,600)	2014
Refined Products (Bbls) – Futures	13,745,755	2015	(280,000)	2014
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(39,287,500)	2015	(7,352,500)	2014
Fixed Swaps/Futures	(39,287,500)	2015	(50,530,000)	2014
Hedged Item — Inventory	39,287,500	2015	50,530,000	2014
Cash Flow Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	—	—	(1,825,000)	2014
Fixed Swaps/Futures	—	—	(12,775,000)	2014
Natural Gas Liquid (Bbls) – Forwards/Swaps	—	—	(780,000)	2014
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.

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.

Marketing & Trading. Regency conducts natural gas marketing and trading activities through its Logistics and Trading subsidiary. Regency engages in activities intended to capitalize on favorable price differentials between various receipt and delivery locations. Regency enters into both financial derivatives and physical contracts. These financial derivatives, primarily basis swaps, are transacted: (i) to economically hedge subscribed capacity exposed to market rate fluctuations and (ii) to mitigate the price risk related to other purchase and sales of natural gas. By entering into a basis swap, one pricing index is exchanged for another, effectively locking in the margin between the natural gas purchase and sale by removing index spread risk on the combined physical and financial transaction. Changes in the fair value of these financial and physical contracts are recorded as adjustments to natural gas sales and realized (unrealized) gain (loss) from derivatives, as appropriate.

Through its natural gas marketing activity, Regency has credit exposure to additional counterparties. Regency minimizes the credit risk associated with natural gas marketing by limiting its exposure to any single counterparty and monitoring the creditworthiness of its counterparties on an ongoing basis. In addition, Regency's natural gas purchase and sale contracts, for certain counterparties, are subject to counterparty netting agreements governing settlement under such natural gas purchase and sales contracts, and when possible, Regency nets the open positions of each counterparty.

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 Audit and Risk Committee of Regency GP is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. Regency GP's Audit and Risk 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, 2014		December 31, 2013	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Non-Trading)				
Natural Gas (MMBtu) — Fixed Swaps/Futures	(25,525,000)	2015	(24,455,000)	2014-2015
Propane (Gallons) — Forwards/Swaps	(29,148,000)	2015	(52,122,000)	2014-2015
NGLs (Barrels) — Forwards/Swaps	(292,000)	2015	(438,000)	2014
WTI Crude Oil (Barrels) — Forwards/Swaps	(1,252,000)	2015-2016	(521,000)	2014

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 anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which are designated as hedges for accounting purposes:

Entity	Term	Type[1]	Notional Amount Outstanding December 31, 2014	Notional Amount Outstanding December 31, 2013
ETP	July 2014[2]	Forward-starting to pay a fixed rate of 4.25% and receive a floating rate	$ —	$ 400
ETP	July 2015[2]	Forward-starting to pay a fixed rate of 3.38% and receive a floating rate	200	—
ETP	July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	—
ETP	July 2017[4]	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	—
ETP	July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	—
ETP	July 2019[4]	Forward-starting to pay a fixed rate of 3.19% and receive a floating rate	300	—
ETP	July 2018	Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70%	—	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 1.73% and receive a fixed rate of 3.60%	200	400
Panhandle	November 2021	Pay a fixed rate of 3.82% and receive a floating rate	—	275

(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.

(3) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.

(4) Represents the effective date. These forward-starting swaps have a term of 30 years with a mandatory termination date the same as the effective date.

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 ETP'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, ETP may at times require collateral under certain circumstances to mitigate credit risk as necessary. ETP also implements 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, ETP utilizes master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

ETP's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, gas and electric utilities and midstream companies. ETP's overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that impact its 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, and 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, 2014 would be $82 million, which would be reduced by less than $1 million due to the netting feature. Regency has elected to present assets and liabilities under master netting agreements gross on the condensed consolidated balance sheets for it derivate contracts outside of its marketing and trading operations.

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, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 43	$ 3	$ —	$ (18)
	43	3	—	(18)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 617	$ 227	$ (577)	$ (209)
Commodity derivatives	107	43	(23)	(48)
Interest rate derivatives	3	47	(155)	(95)
Embedded derivatives in Regency Preferred Units	—	—	(16)	(19)
	727	317	(771)	(371)
Total derivatives	$ 770	$ 320	$ (771)	$ (389)

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, 2014	Asset Derivatives December 31, 2013	Liability Derivatives December 31, 2014	Liability Derivatives December 31, 2013
Derivatives in offsetting agreements:					
OTC contracts	Price risk management assets (liabilities)	$ 23	$ 42	$ (23)	$ (38)
Broker cleared derivative contracts	Other current assets	674	264	(574)	(318)
		697	306	(597)	(356)
Offsetting agreements:					
Counterparty netting	Price risk management assets (liabilities)	(19)	(36)	19	36
Payments on margin deposit	Other current assets	5	(1)	(22)	55
		(14)	(37)	(3)	91
Net derivatives with offsetting agreements		683	269	(600)	(265)
Derivatives without offsetting agreements		87	51	(171)	(124)
Total derivatives		$ 770	$ 320	$ (771)	$ (389)

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, 2014	2013	2012
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$ —	$ (1)	$ 8
Total	$ —	$ (1)	$ 8

	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, 2014	2013	2012
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$ (3)	$ 4	$ 14
Total		$ (3)	$ 4	$ 14

	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,		
		2014	2013	2012
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ (8)	$ 8	$ 54
Total		$ (8)	$ 8	$ 54

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2014	2013	2012
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$ (6)	$ (11)	$ (7)
Commodity derivatives – Non-trading	Cost of products sold	199	(21)	26
Commodity contracts – Non-trading	Deferred gas purchases	—	(3)	(26)
Interest rate derivatives	Gains (losses) on interest rate derivatives	(157)	53	(19)
Embedded derivatives	Other income	3	6	14
Total		$ 39	$ 24	$ (12)

14. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all eligible employees, including those of ETP, Regency and Lake Charles LNG. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries have made matching contributions of $59 million, $47 million and $30 million to the 401(k) savings plan for the years ended December 31, 2014, 2013 and 2012, respectively.

Pension and Other Postretirement Benefit Plans

Panhandle

Panhandle offered postretirement health care and life insurance plans that were available to substantially all of its employees, pending the retiree meeting certain age and service requirements.

Sunoco, Inc.

Sunoco, Inc. sponsors a defined benefit pension plan, which was frozen for most participants on June 30, 2010. On October 31, 2014, Sunoco, Inc. terminated the plan and anticipates approval for the distribution of assets from the plan, pending approval from the Pension Benefit Guaranty Corporation and the IRS, in the fourth quarter of 2015.

Sunoco, Inc. also has a plan which provides health care benefits for substantially all of its current retirees. The cost to provide the postretirement benefit plan is shared by Sunoco, Inc. and its retirees. Access to postretirement medical benefits was phased out or eliminated for all employees retiring after July 1, 2010. In March, 2012, Sunoco, Inc. established a trust for its postretirement benefit liabilities. Sunoco made a tax-deductible contribution of approximately $200 million to the trust. The funding of the trust eliminated substantially all of Sunoco, Inc.'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, 2014			December 31, 2013		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 632	$ 61	$ 223	$ 1,117	$ 78	$ 296
Service cost	—	—	—	3	—	—
Interest cost	28	3	5	33	2	6
Amendments	—	—	1	—	—	2
Benefits paid, net	(45)	(9)	(28)	(99)	(16)	(26)
Actuarial (gain) loss and other	130	10	2	(74)	(3)	(14)
Settlements	(27)	—	—	(95)	—	—
Dispositions	—	—	—	(253)	—	(41)
Benefit obligation at end of period	$ 718	$ 65	$ 203	$ 632	$ 61	$ 223
Change in plan assets:						
Fair value of plan assets at beginning of period	600	—	284	906	—	312
Return on plan assets and other	70	—	7	43	—	17
Employer contributions	—	—	9	—	—	8
Benefits paid, net	(45)	—	(28)	(99)	—	(26)
Settlements	(27)	—	—	(95)	—	—
Dispositions	—	—	—	(155)	—	(27)
Fair value of plan assets at end of period	$ 598	$ —	$ 272	$ 600	$ —	$ 284
Amount underfunded (overfunded) at end of period	$ 120	$ 65	$ (69)	$ 32	$ 61	$ (61)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$ —	$ —	$ 96	$ —	$ —	$ 86
Current liabilities	—	(9)	(2)	—	(9)	(2)
Non-current liabilities	(120)	(56)	(25)	(32)	(52)	(23)
	$ (120)	$ (65)	$ 69	$ (32)	$ (61)	$ 61
Amounts recognized in accumulated other comprehensive loss (pre-tax basis) consist of:						
Net actuarial gain	$ 18	$ 7	$ (21)	$ (86)	$ (4)	$ (25)
Prior service cost	—	—	18	—	—	18
	$ 18	$ 7	$ (3)	$ (86)	$ (4)	$ (7)

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2014			December 31, 2013		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$ 718	$ 65	N/A	$ 632	61	N/A
Accumulated benefit obligation	718	65	203	632	61	$ 223
Fair value of plan assets	598	—	272	600	—	284

Components of Net Periodic Benefit Cost

	December 31, 2014		December 31, 2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net Periodic Benefit Cost:				
Service cost	$ —	$ —	$ 3	$ —
Interest cost	31	5	35	6
Expected return on plan assets	(40)	(8)	(54)	(9)
Prior service cost amortization	—	1	—	1
Actuarial loss amortization	(1)	(1)	2	—
Settlements	(4)	—	(2)	—
	(14)	(3)	(16)	(2)
Regulatory adjustment[1]	—	—	5	—
Net periodic benefit cost	$ (14)	$ (3)	$ (11)	$ (2)

(1) Southern Union, the predecessor of Panhandle, 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, 2014		December 31, 2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.62%	2.24%	4.65%	2.33%
Rate of compensation increase	N/A	N/A	N/A	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, 2014		December 31, 2013	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.65%	3.02%	3.50%	2.68%
Expected return on assets:				
Tax exempt accounts	7.50%	7.00%	7.50%	6.95%
Taxable accounts	N/A	4.50%	N/A	4.42%
Rate of compensation increase	N/A	N/A	N/A	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 Panhandle's and Sunoco, Inc.'s other postretirement benefit plans are shown in the table below:

	December 31,	
	2014	2013
Health care cost trend rate	7.09%	7.57%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.41%	5.42%
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 Panhandle 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 other postretirement plan asset portfolio, Panhandle has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of up to 10%.

The investment strategy of Sunoco, Inc. 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 and maintain a sufficient funded status of the plans. In anticipation of the pension plan termination, Sunoco, Inc. targeted the asset allocations to a more stable position by investing in growth assets and liability hedging assets.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

	Fair Value as of December 31, 2014	Fair Value Measurements at December 31, 2014 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 25	$ 25	$ —	$ —
Mutual funds [1]	110	—	110	—
Fixed income securities	463	—	463	—
Total	$ 598	$ 25	$ 573	$ —

(1) Comprised of 100% equities as of December 31, 2014.

	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 41% equities, 45% fixed income securities, and 14% in other investments as of December 31, 2013.

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, 2014	Fair Value Measurements at December 31, 2014 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
Asset Category:				
Cash and Cash Equivalents	$ 9	$ 9	$ —	$ —
Mutual funds (1)	138	138	—	—
Fixed income securities	125	—	125	—
Total	$ 272	$ 147	$ 125	$ —

(1) Primarily comprised of approximately 53% equities, 41% fixed income securities, 6% cash as of December 31, 2014.

	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.

Contributions

We expect to contribute approximately $129 million to pension plans and approximately $10 million to other postretirement plans in 2015. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Panhandle's and Sunoco, Inc.'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)
2015	$ 717	$ 9	$ 28
2016	—	8	26
2017	—	7	25
2018	—	7	23
2019	—	6	22
2020 – 2024	—	23	65

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.

Panhandle does not expect to receive any Medicare Part D subsidies in any future periods.

15. 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 16).

In addition, subsidiaries of ETE recorded sales with affiliates of $965 million, $1.44 billion and $189 million during the years ended December 31, 2014, 2013 and 2012, respectively.

16. REPORTABLE SEGMENTS:

In April 2015, ETP and Regency completed the previously announced merger of an indirect subsidiary of ETP, with and into Regency, with Regency surviving the merger as a wholly-owned subsidiary of ETP (the "Regency Merger"). As part of the merger consideration, each Regency common unit and Class F unit was converted into the right to receive 0.4124 ETP Common Units. Based on the Regency units outstanding, ETP issued approximately 172.2 million ETP Common Units to Regency unitholders, including approximately 15.5 million units issued to ETP subsidiaries. The approximately 1.9 million outstanding Regency series A preferred units were converted into corresponding new ETP Series A Preferred Units.

In connection with the transaction, ETE, which owns the general partner and 100% of the incentive distribution rights of ETP, will reduce the incentive distributions it receives from ETP by a total of $320 million over a five-year period. The IDR subsidy will be $80 million in the first year post-closing and $60 million per year for the following four years.

ETP and Regency are under common control of ETE; therefore, we accounted for the Regency Merger at historical cost as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency beginning May 26, 2010 (the date ETE acquired Regency's general partner).

Prior the the Regency Merger, the Investment in Regency was presented as a separate segment. Due to ETP's consolidation of Regency for all periods presented, the Investment in Regency segment has been consolidated into the Investment in ETP segment and is no longer presented separately.

Subsequent to ETP's acquisition of Regency, our financial statements reflect the following reportable business segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Lake Charles LNG, including the operations of Lake Charles LNG; 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 define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, depletion, 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 and amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations. Based on the change in our reportable segments we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

Eliminations in the tables below include the following:

- ETP's Segment Adjusted EBITDA reflected the results of Lake Charles LNG prior to the Lake Charles LNG Transaction, which was effective January 1, 2014. The Investment in Lake Charles LNG segment reflected the results of operations of Lake Charles LNG for all periods presented. Consequently, the results of operations of Lake Charles LNG were reflected in two segments for the years ended December 31, 2013 and 2012 beginning March 26, 2012. Therefore, the results of Lake Charles LNG were included in eliminations for 2013 and 2012.

	Years Ended December 31,		
	2014	2013	2012
Revenues:			
Investment in ETP	$ 55,475	$ 48,335	$ 16,964
Investment in Lake Charles LNG	216	216	166
Adjustments and Eliminations	—	(216)	(166)
Total revenues	$ 55,691	$ 48,335	$ 16,964
Costs of products sold:			
Investment in ETP	$ 48,389	$ 42,554	$ 13,088
Total costs of products sold	$ 48,389	$ 42,554	$ 13,088
Depreciation, depletion and amortization:			
Investment in ETP	1,669	1,258	827
Investment in Lake Charles LNG	39	39	30
Corporate and Other	16	16	14
Total depreciation, depletion and amortization	$ 1,724	$ 1,313	$ 871

	Years Ended December 31,		
	2014	2013	2012
Equity in earnings of unconsolidated affiliates:			
Investment in ETP	$ 332	$ 236	$ 212
Total equity in earnings of unconsolidated affiliates	$ 332	$ 236	$ 212

	Years Ended December 31,		
	2014	2013	2012
Segment Adjusted EBITDA:			
Investment in ETP	$ 5,710	$ 4,404	$ 3,139
Investment in Lake Charles LNG	195	187	135
Corporate and Other	(97)	(43)	(52)
Adjustments and Eliminations	32	(181)	(117)
Total Segment Adjusted EBITDA	5,840	4,367	3,105
Depreciation, depletion and amortization	(1,724)	(1,313)	(871)
Interest expense, net of interest capitalized	(1,369)	(1,221)	(1,018)
Bridge loan related fees	—	—	(62)
Gain on deconsolidation of Propane Business	—	—	1,057
Gain on sale of AmeriGas common units	177	87	—
Goodwill impairment	(370)	(689)	—
Gains (losses) on interest rate derivatives	(157)	53	(19)
Non-cash unit-based compensation expense	(82)	(61)	(47)
Unrealized gains on commodity risk management activities	116	48	10
Losses on extinguishments of debt	(25)	(162)	(123)
Inventory valuation adjustments	(473)	3	(75)
Adjusted EBITDA related to discontinued operations	(27)	(76)	(99)
Adjusted EBITDA related to unconsolidated affiliates	(748)	(727)	(647)
Equity in earnings of unconsolidated affiliates	332	236	212
Non-operating environmental remediation	—	(168)	—
Other, net	(73)	(2)	14
Income from continuing operations before income tax expense	$ 1,417	$ 375	$ 1,437

	December 31,		
	2014	2013	2012
Total assets:			
Investment in ETP	$ 62,674	$ 49,900	$ 48,394
Investment in Lake Charles LNG	1,210	1,338	1,917
Corporate and Other	1,153	720	707
Adjustments and Eliminations	(568)	(1,628)	(2,114)
Total	$ 64,469	$ 50,330	$ 48,904

	Years Ended December 31,		
	2014	2013	2012
Additions to property, plant and equipment, net of contributions in aid of construction costs (accrual basis):			
Investment in ETP	$ 5,494	$ 3,327	$ 3,533
Investment in Lake Charles LNG	1	2	4
Adjustments and Eliminations	64	13	(20)
Total	$ 5,559	$ 3,342	$ 3,517

	December 31,		
	2014	2013	2012
Advances to and investments in affiliates:			
Investment in ETP	$ 3,760	$ 4,050	$ 4,768
Adjustments and Eliminations	(101)	(36)	(31)
Total	$ 3,659	$ 4,014	$ 4,737

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,		
	2014	2013	2012
Intrastate Transportation and Storage	$ 2,857	$ 2,452	$ 2,191
Interstate Transportation and Storage	1,072	1,309	1,109
Midstream	6,823	4,276	3,077
Liquids Transportation and Services	3,911	2,126	650
Investment in Sunoco Logistics	18,088	16,639	3,189
Retail Marketing	22,487	21,012	5,926
All Other	3,331	2,597	1,762
Total revenues	58,569	50,411	17,904
Less: Intersegment revenues	3,094	2,076	940
Revenues from external customers	$ 55,475	$ 48,335	$ 16,964

Investment in Lake Charles LNG

Lake Charles LNG's revenues of $216 million, $216 million and $166 million for the year ended December 31, 2014, 2013 and 2012, respectively, were related to LNG terminalling.

17. 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.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2014:					
Revenues	$ 13,080	$ 14,143	$ 14,987	$ 13,481	$ 55,691
Gross margin	1,638	1,792	1,972	1,900	7,302
Operating income	710	773	822	165	2,470
Net income (loss)	448	500	470	(294)	1,124
Limited Partners' interest in net income	167	163	188	111	629
Basic net income per limited partner unit	$ 0.15	$ 0.15	$ 0.18	$ 0.11	$ 0.58
Diluted net income per limited partner unit	$ 0.15	$ 0.15	$ 0.18	$ 0.11	$ 0.58

	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	$ 0.08	$ 0.11	$ 0.14	$ (0.16)	$ 0.18
Diluted net income (loss) per limited partner unit	$ 0.08	$ 0.11	$ 0.14	$ (0.16)	$ 0.18

The three months ended December 31, 2014 reflected the unfavorable impacts of $456 million related to non-cash inventory valuation adjustments primarily in ETP's investment in Sunoco Logistics and retail marketing operations and Regency's recognition of a goodwill impairment of $370 million. The three months ended December 31, 2013 reflected ETP's recognition of a goodwill impairment of $689 million.

18. 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,	
	2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 8
Accounts receivable from related companies	14	5
Other current assets	1	—
Total current assets	17	13
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	5,390	3,841
INTANGIBLE ASSETS, net	10	14
GOODWILL	9	9
OTHER NON-CURRENT ASSETS, net	46	41
Total assets	$ 5,472	$ 3,918
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable to related companies	$ 11	$ 11
Interest payable	58	24
Accrued and other current liabilities	3	3
Total current liabilities	72	38
LONG-TERM DEBT, less current maturities	4,680	2,801
NOTE PAYABLE TO AFFILIATE	54	—
OTHER NON-CURRENT LIABILITIES	2	1
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL:		
General Partner	(1)	(3)
Limited Partners:		
Limited Partners – Common Unitholders (1,077,533,798 and 1,119,846,600 units authorized, issued and outstanding at December 31, 2014 and 2013, respectively)	648	1,066
Class D Units (3,080,000 units authorized, issued and outstanding)	22	6
Accumulated other comprehensive income (loss)	(5)	9
Total partners' capital	664	1,078
Total liabilities and partners' capital	$ 5,472	$ 3,918

STATEMENTS OF OPERATIONS

	Years Ended December 31, 2014	2013	2012
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$ (111)	$ (56)	$ (53)
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(205)	(210)	(235)
Bridge loan related fees	—	—	(62)
Equity in earnings of unconsolidated affiliates	955	617	666
Gains (losses) on interest rate derivatives	—	9	(15)
Loss on extinguishment of debt	—	(157)	—
Other, net	(5)	(8)	(4)
INCOME BEFORE INCOME TAXES	634	195	297
Income tax expense (benefit)	1	(1)	(7)
NET INCOME	633	196	304
GENERAL PARTNER’S INTEREST IN NET INCOME	2	—	2
CLASS D UNITHOLDER’S INTEREST IN NET INCOME	2	—	—
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 629	$ 196	$ 302

STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2014	2013	2012
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 816	$ 768	$ 555
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash paid for acquisitions	—	—	(1,113)
Proceeds from ETP Holdco Transaction	—	1,332	—
Contributions to unconsolidated affiliates	(118)	(8)	(487)
Purchase of additional interest in Regency	(800)	—	—
Note payable to affiliate	54	—	—
Note receivable from affiliate	—	—	(221)
Payments received on note receivable from affiliate	—	166	55
Net cash provided by (used in) investing activities	(864)	1,490	(1,766)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	3,020	2,080	2,108
Principal payments on debt	(1,142)	(3,235)	(162)
Distributions to partners	(821)	(733)	(666)
Redemption of Preferred Units	—	(340)	—
Units repurchased under buyback program	(1,000)	—	—
Debt issuance costs	(15)	(31)	(78)
Net cash provided by (used in) financing activities	42	(2,259)	1,202
DECREASE IN CASH AND CASH EQUIVALENTS	(6)	(1)	(9)
CASH AND CASH EQUIVALENTS, beginning of period	8	9	18
CASH AND CASH EQUIVALENTS, end of period	$ 2	$ 8	$ 9

Exhibit 99.2

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 statements of comprehensive income, equity, and cash flows of Sunoco Logistics Partners L.P. (the "Partnership") for the period from October 5, 2012 to December 31, 2012 (successor) and the period from January 1, 2012 to October 4, 2012 (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 results of operations and cash flows of Sunoco Logistics Partners L.P. for the period from October 5, 2012 to December 31, 2012 (successor) and the period from January 1, 2012 to October 4, 2012 (predecessor), in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Philadelphia, Pennsylvania
March 1, 2013

Exhibit 99.3

REPORT OF INDEPENDENT AUDITORS

The Shareholders of Susser Holdings Corporation

We have audited the accompanying consolidated financial statements of Susser Holdings Corporation (the Company) which comprise the consolidated balance sheets as of December 31, 2014 and December 29, 2013, and the related consolidated statements of operations and comprehensive income, shareholders' equity, and cash flows for the periods from September 1, 2014 through December 31, 2014 and December 30, 2013 through August 31, 2014, and the years ended December 29, 2013 and December 30, 2012 (not presented separately herein) and the related notes to the consolidated financial statements.

Management’s Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor’s Responsibility

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 involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risk of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors considers internal control relevant to the entity’s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity’s internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Susser Holdings Corporation at December 31, 2014 and December 29, 2013, and the consolidated results of its operations and its cash flows for the periods from September 1, 2014 through December 31, 2014 and December 30, 2013 through August 31, 2014, and the years ended December 29, 2013 and December 31, 2012, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
February 28, 2015, except for Note 2, as to which the date is April 30, 2015

Exhibit 99.4

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Sunoco LP and
Unitholders of Sunoco LP

We have audited the accompanying consolidated balance sheets of Sunoco LP (formerly Susser Petroleum Partners LP) as of December 31, 2014 and 2013, and the related consolidated statements of operations and comprehensive income, partners' equity, and cash flows for the periods from September 1, 2014 through December 31, 2014 and January 1, 2014 through August 31, 2014, and the years ended December 31, 2013 and 2012 (not presented separately herein). 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Sunoco LP at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for the periods from September 1, 2014 through December 31, 2014 and January 1, 2014 through August 31, 2014, and the years ended December 31, 2013 and 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Sunoco LP's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 27, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2015