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**

August 14, 2017
Date of Report (Date of earliest event reported)

ENERGY TRANSFER PARTNERS, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	1-31219	73-1493906
(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)

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:

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

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

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

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

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 8.01. Other Events.

This Current Report on Form 8-K is being filed principally to reflect certain retrospective revisions for amounts reported in reportable segments that have been made to the consolidated financial statements of Energy Transfer Partners, L.P. (“ETP” or the “Partnership”) that were previously filed with the Securities and Exchange Commission by the Partnership on February 24, 2017 as Items 1, 6, 7 and 8 to its Annual Report on Form 10-K for the year ended December 31, 2016 (the “2016 Form 10-K”).

These retrospective revisions are due to the merger of Sunoco Logistics Partners L.P. (the registrant) and Energy Transfer Partners, L.P. (“pre-merger ETP”) in April 2017. Following the closing of the merger, the registrant changed its name from “Sunoco Logistics Partners L.P.” to “Energy Transfer Partners, L.P.”

The retrospective revisions reflected in the accompanying information include the following:

- The merger resulted in the legal acquiree (pre-merger ETP) being treated as the surviving consolidated entity from an accounting perspective, while the surviving entity from a legal perspective was the registrant (the entity named Sunoco Logistics Partners L.P. prior to the merger). Therefore, for the pre-merger periods, the registrant’s consolidated financial statements have been retrospectively revised to reflect the consolidated financial statements of the legal acquiree (pre-merger ETP) as the predecessor to the post-merger combined entity.
- In connection with the merger, the unitholders of pre-merger ETP received 1.5 common units of the registrant for each common unit of pre-merger ETP they owned. As pre-merger ETP was treated as the predecessor of the post-merger combined entity, the historical common units and net income or loss per limited partner unit amounts presented in the accompanying financial statements and other information have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange.
- Subsequent to the merger, the combined entity changed the presentation of its reportable segments. Accordingly, the accompanying financial statements and other information have been retrospectively revised to reflect the post-merger reportable segments.
- Condensed consolidating financial information has been included in the notes to the consolidated financial statements pursuant to Rule 3-10 of Regulation S-X. The condensed consolidating financial information has been presented as if the merger occurred on January 1, 2014 (the beginning of the earliest period presented in the accompanying financial statements).

In order to preserve the nature and character of the disclosures previously included in pre-merger ETP's Form 10-K for the year ended December 31, 2016 and in the registrant's Form 8-K filed on May 8, 2017, the items included in this Form 8-K have been updated solely for matters relating specifically to the retrospective revision of amounts reported in ETP's reportable segments in its consolidated financial statements and the other matters, as described above. 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 2016 Form 10-K to reflect events or occurrences after the date of the filing of the 2016 Form 10-K, February 24, 2017. Therefore, this Form 8-K should be read in conjunction with the 2016 Form 10-K, and filings made by ETP with the SEC subsequent to the filing of the 2016 Form 10-K, including ETP’s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2017 and June 30, 2017 filed on May 4, 2017 and August 9, 2017, respectively.

Item 9.01 of this Current Report on Form 8-K revises certain information contained in ETP’s 2016 Form 10-K to reflect these changes in amounts reported in ETP's reportable segments. In particular, Exhibit 99.1 contains a revised description of ETP’s business segments, financial statements and Management’s Discussion and Analysis of Financial Condition and Results of Operations.

Item 9.01 of this Current Report on Form 8-K also includes Exhibit 99.2, which revises the calculations of the ratio of earnings to fixed charges for each of the five years ended December 31, 2016 to reflect the post-merger combined entities on a consolidated basis for all periods.

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 Partners, L.P.
99.1	Revised Energy Transfer Partners, L.P. description of the business, financial statements as of December 31, 2016 and 2015, and for each of the three years in the period ended December 31, 2016, and Management's Discussion and Analysis of Financial Condition and Results of Operations.
99.2	Computation of Ratio of Earnings to Fixed Charges
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 PARTNERS, L.P.	
		By:	Energy Transfer Partners GP, L.P. its General Partner
		By:	Energy Transfer Partners, L.L.C. its General Partner
Date:	August 14, 2017	By:	/s/ Thomas E. Long
			Thomas E. Long Chief Financial Officer (duly authorized to sign on behalf of the registrant)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 24, 2017 (except for all unit and per unit amounts as discussed in Note 1 and for Notes 15 and 17, which are as of August 14, 2017) with respect to the consolidated financial statements of Energy Transfer Partners, L.P. included in this Current Report on Form 8-K. We consent to the incorporation by reference of said report in the Registration Statements of Energy Transfer Partners, L.P. on Forms S-3 (File No. 333-219224, File No. 333-212962, File No. 333-206302, and File No. 333-206301) and on Forms S-8 (File No. 333-217592, File No. 333-208327, and File No. 333-96897).

/s/ GRANT THORNTON LLP

Dallas, Texas
August 14, 2017

TABLE OF CONTENTS

Forward-Looking Statements

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

Definitions

The following is a list of certain acronyms and terms generally used in the energy industry and throughout this document:

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Aqua – PVR	Aqua – PVR Water Services, LLC
AROs	asset retirement obligations
Bbls	barrels
Bcf	billion cubic feet
BG	BG Group plc
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
Citrus	Citrus, LLC
Coal Handling	Coal Handling Solutions LLC, Kingsport Handling LLC, and Kingsport Services LLC, now known as Materials Handling Solutions LLC
CrossCountry	CrossCountry Energy, LLC
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
Eagle Rock	Eagle Rock Energy Partners, L.P.
ELG	Edwards Lime Gathering LLC
EPA	U.S. Environmental Protection Agency
ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC MEP	ETC Midcontinent Express Pipeline, L.L.C.
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company

ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ETE Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ET Interstate	Energy Transfer Interstate Holdings, LLC
ET Rover	ET Rover Pipeline LLC
ETP Credit Facility	ETP's $3.75 billion 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
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
Gulf States	Gulf States Transmission LLC
HPC	RIGS Haynesville Partnership Co. and its wholly-owned subsidiary, Regency Intrastate Gas LP
HOLP	Heritage Operating, L.P.
Hoover Energy	Hoover Energy Partners, LP
IDRs	incentive distribution rights
KMI	Kinder Morgan Inc.
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a subsidiary of ETE
LCL	Lake Charles LNG Export Company, LLC
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lone Star	Lone Star NGL LLC
LPG	liquefied petroleum gas
MACS	Mid-Atlantic Convenience Stores, LLC
MEP	Midcontinent Express Pipeline LLC
Mi Vida JV	Mi Vida JV LLC
MMBtu	million British thermal units
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
ORS	Ohio River System LLC

OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PennTex	PennTex Midstream Partners, LP
PES	Philadelphia Energy Solutions
PHMSA	Pipeline Hazardous Materials Safety Administration
Preferred Units	ETP Series A cumulative convertible preferred units
PVR	PVR Partners, L.P.
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, LLC, a joint venture between subsidiaries of ETC OLP and Sunoco, Inc.
RIGS	Regency Intrastate Gas System
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC
Sunoco GP	Sunoco GP LLC, the general partner of Sunoco LP
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco LP	Sunoco LP (previously named Susser Petroleum Partners, LP)
Sunoco Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
Susser	Susser Holdings Corporation
Transwestern	Transwestern Pipeline Company, LLC
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle

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, losses on extinguishments of debt 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.

PART I

ITEM 1. BUSINESS

Overview

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Segment Overview

See Note 15 to our consolidated financial statements for additional financial information about our segments.

Intrastate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users, storage facilities, utilities and other pipelines. Through our intrastate transportation and storage segment, we own and operate approximately 7,900 miles of natural gas transportation pipelines with approximately 15.2 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas. We also own a 49.99% general partner interest in RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets.

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

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

We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and marketing companies on our HPL System. Generally, we purchase 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, our intrastate transportation and storage segment generates revenues from fees charged for storing customers' working natural gas in our storage facilities and from managing natural gas for our own account.

Interstate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users, storage facilities, utilities and other pipelines. Through our interstate transportation and storage segment, we directly own and operate approximately 11,800 miles of interstate natural gas pipelines with approximately 10.3 Bcf/d of transportation capacity and have a 50% interest in the joint venture that owns 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 5,325 mile pipeline system that extends from South Texas through the Gulf Coast to south Florida.

Our interstate transportation and storage segment includes Panhandle, which owns and operates a large natural gas open-access interstate pipeline network. The pipeline network, consisting of the Panhandle, 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.

We also own a 50% interest in the MEP pipeline system, which is operated by KMI, and has the capability to transport up to 1.8 Bcf/d of natural gas.

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 in the process of converting a portion of the Trunkline gas pipeline to crude oil transportation.

The results from our interstate transportation and storage segment are primarily derived from the fees we earn from natural gas transportation and storage services.

Midstream Segment

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

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 margins for NGLs extracted from the gas stream. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream.

Through our midstream segment, we own and operate natural gas and NGL gathering pipelines, natural gas processing plants, natural gas treating facilities and natural gas conditioning facilities with an aggregate processing, treating and conditioning capacity of approximately 12.3 Bcf/d. Our midstream segment focuses on the gathering, compression, treating, blending, and processing, and our operations are currently concentrated in major producing basins and shales, including the Austin Chalk trend and Eagle Ford Shale in South and Southeast Texas, the Permian Basin in West Texas and New Mexico, the Barnett Shale and Woodford Shale in North Texas, the Bossier Sands in East Texas, the Marcellus Shale in West Virginia and Pennsylvania, the Haynesville Shale in East Texas and Louisiana, and the Cotton Valley Shale in Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment also includes a 60% interest in ELG, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in South Texas, a 33.33% membership interest in Ranch Westex JV LLC, which processes natural gas delivered from the NGLs-rich shale formations in West Texas, a 75% membership interest in ORS, which operates a natural gas gathering system in the Utica shale in Ohio, and a 50% interest in Mi Vida JV, which operates a cryogenic processing plant and related facilities in West Texas, a 51% membership interest in Aqua – PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, and a 50% interest in Sweeny Gathering LP, which operates a natural gas gathering facility in South Texas.

Our midstream segment results are derived primarily from margins we earn for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems and the natural gas and NGL volumes processed at our processing and treating facilities.

NGL and Refined Products Transportation and Services Segment

Our NGL operations transports, stores and executes acquisition and marketing activities utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGL markets.

Liquids 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.

Our NGL and refined products transportation and services segment includes approximately 2,300 miles of NGL pipelines, five NGL and propane fractionation facilities with an aggregate capacity of 545,000 Bbls/d and NGL storage facilities with aggregate working storage capacity of approximately 53 million Bbls. Four of our NGL and propane fractionation facilities and 50 million Bbls of our NGL storage capacity are located at Mont Belvieu, Texas, one NGL fractionation facility is located in Geismar, Louisiana, and the segment has 3 million Bbls of salt dome storage capacity near Hattiesburg, Mississippi. The NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu. In addition, we own and operate the 82-mile Rio Bravo crude oil pipeline.

Terminalling services are facilitated by approximately 5 million barrels of NGLs storage capacity, including approximately 1 million barrels of storage at our Nederland, Texas terminal facility and 3 million barrels at our Marcus Hook, Pennsylvania terminal facility (the “Marcus Hook Industrial Complex”). These operations also carry out our NGLs blending activities, including utilizing our patented butane blending technology.

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 fractionation revenue is principally generated from fees charged to customers under take-or-pay contracts. Take-or-pay contracts have minimum payment obligations for throughput commitments requiring the customer to pay regardless of whether a fixed volume is fractionated from raw make into purity NGL products. Fractionation fees are market-based, negotiated with customers and competitive with other fractionators along the Gulf Coast.

NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are firm take-or-pay contracts on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery and custody transfer fees.

This segment also includes revenues earned from the marketing of NGLs and processing and fractionating refinery off-gas. Marketing of NGLs primarily generates margin from selling ratable NGLs to end users and from optimizing storage assets. Processing and fractionation of refinery off-gas margin is generated from a percentage-of-proceeds of O-grade product sales and income sharing contracts, which are subject to market pricing of olefins and NGLs.

Our refined products operations provide transportation and terminalling services, through the use of approximately 1,800 miles of refined products pipelines and approximately 40 active refined products marketing terminals. Our marketing terminals are located primarily in the northeast, midwest and southwest United States, with approximately 8 million barrels of refined products storage capacity. Our refined products operations include our Eagle Point facility in New Jersey, which has approximately 6 million barrels of refined products storage capacity. The operations also include our equity ownership interests in four refined products pipeline companies. The operations also perform terminalling activities at our Marcus Hook Industrial Complex. Our refined products operations utilize its integrated pipeline and terminalling assets, as well as acquisition and marketing activities, to service refined products markets in several regions in the United States.

Crude Oil Transportation and Services Segment

Our crude oil operations provide transportation, terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest and northeastern United States. Included within the operations are approximately 6,100 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States and equity ownership interests in two crude oil pipelines. Our crude oil terminalling services operates with an aggregate storage capacity of approximately 33 million barrels, including approximately 26 million barrels at our Gulf Coast terminal in Nederland, Texas and approximately 3 million barrels at its Fort Mifflin terminal complex in Pennsylvania. Our crude oil acquisition and marketing activities utilize our pipeline and terminal assets, our proprietary fleet crude oil tractor trailers and truck unloading facilities, as well as third-party assets, to service crude oil markets principally in the mid-continent United States.

All Other Segment

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

- We own an equity method investment in limited partnership units of Sunoco LP consisting of 43.5 million units, representing 44.3% of Sunoco LP’s total outstanding common units.
- Our wholly-owned subsidiary, 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.
- We conduct marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices of natural gas, less the costs of transportation. For the off-system gas, we purchase gas or act as an agent for small independent producers that may not have marketing operations.
- We own all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.
- We own 100% of the membership interests of Energy Transfer Group, L.L.C. (“ETG”), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. (“ETT”). ETT provides compression services to customers engaged in the transportation of natural gas, including our other segments.
- We own a 40% interest in the parent of LCL, which is developing a LNG liquefaction project, as described further under “Asset Overview – All Other” below.
- We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.
- We are involved in the management of coal and natural resources properties and the related collection of royalties. We also earn 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 include Coal Handling, which owns and operates end-user coal handling facilities.
- We also own PEI Power Corp. and PEI Power II, which own and operate a facility in Pennsylvania that generates a total of 75 megawatts of electrical power.

<u>Asset Overview</u>

The descriptions below include summaries of significant assets within the Partnership’s reportable segments. Amounts, such as capacities, volumes and miles included in the descriptions below are approximate and are based on information currently available; such amounts are subject to change based on future events or additional information.

Intrastate Transportation and Storage

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

Description of Assets	Ownership Interest (%)	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Storage Capacity (Bcf/d)
ET Fuel System	100%	2,780	5.2	11.2
Oasis Pipeline	100%	750	2.3	—
HPL System	100%	3,920	5.3	52.5
East Texas Pipeline	100%	460	2.4	—
RIGS Haynesville Partnership Co.	49.99%	450	2.1	—

The following information describes our principal intrastate transportation and storage assets:

- 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 has bi-directional capabilities. It 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 our Bethel natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 5.2 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. Storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 2023.

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

- The Oasis Pipeline is primarily a 36-inch natural gas pipeline. It has bi-directional capabilities 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 connects to the Waha and Katy market hubs and has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

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

- 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 us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, as well as our 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, 2016, we had approximately 10.8 Bcf committed under fee-based arrangements with third parties and approximately 36.9 Bcf stored in the facility for our own account.

- The East Texas Pipeline connects three treating facilities, one of which we own, with our Southeast Texas System. The East Texas pipeline serves producers in East and North Central Texas and provided access to the Katy Hub. The East Texas pipeline expansions include the 36-inch East Texas extension to connect our Reed compressor station in Freestone County to our Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting our Cleburne to Carthage pipeline to the HPL System.

- RIGS is a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets. The Partnership owns a 49.99% general partner interest in RIGS.

Interstate Transportation and Storage

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

Description of Assets	Ownership Interest (%)	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Gas Capacity (Bcf/d)
Florida Gas Transmission Pipeline	50%	5,325	3.1	—
Transwestern Pipeline	100%	2,600	2.1	—
Panhandle Eastern Pipe Line	100%	6,000	2.8	83.9
Trunkline Gas Pipeline	100%	2,000	0.9	13.0
Tiger Pipeline	100%	195	2.4	—
Fayetteville Express Pipeline	50%	185	2.0	—
Sea Robin Pipeline	100%	1,000	2.0	—
Midcontinent Express Pipeline	50%	500	1.8	—
Gulf States	100%	10	0.1	—

The following information describes our principal interstate transportation and storage assets:

- The Florida Gas Transmission Pipeline ("FGT") is an open-access interstate pipeline system with a mainline capacity of 3.1 Bcf/d and approximately 5,325 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The FGT 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 66% of the natural gas consumed in the state. In addition, FGT's system operates and maintains over 81 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. FGT is owned by Citrus, a 50/50 joint venture with KMI.
- 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 bi-directional capabilities and 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 panhandles. 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 660 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.
- The Panhandle Eastern Pipe Line's transmission system consists of four large diameter pipelines with bi-directional capabilities, 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.
- The Trunkline Gas Pipeline's transmission system consists of one large diameter pipeline with bi-directional capabilities, extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and Michigan.
- The Tiger Pipeline is an approximately 195-mile interstate natural gas pipeline with bi-directional capabilities, that connects to our dual 42-inch pipeline system near Carthage, Texas, extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana.
- The 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 Fayetteville Express Pipeline is owned by a 50/50 joint venture with KMI.
- 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.

- The Midcontinent Express Pipeline is an approximately 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. The Midcontinent Express Pipeline is owned by a 50/50 joint venture with KMI.
- Gulf States owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

Midstream

The following details our assets in the midstream segment:

Description of Assets	Net Gas Processing Capacity (MMcf/d)	Net Gas Treating Capacity (MMcf/d)
South Texas Region:		
Southeast Texas System	410	510
Eagle Ford System	1,920	930
Ark-La-Tex Region	1,025	1,186
North Central Texas Region	740	1,120
Permian Region	1,743	1,580
Mid-Continent Region	885	20
Eastern Region	—	70

The following information describes our principal midstream assets:

South Texas Region:

- The Southeast Texas System is an integrated system that gathers, compresses, treats, processes, dehydrates and transports natural gas from the Austin Chalk trend and Eagle Ford shale formation. 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 also connected to the Oasis Pipeline. The Southeast Texas System includes two natural gas processing plant (La Grange and Alamo) with aggregate capacity of 410 MMcf/d and natural gas treating facilities with aggregate capacity of 510 MMcf/d. The La Grange and Alamo processing plants are natural gas processing plants that process the rich gas that flows through our gathering system to produce residue gas and NGLs. Residue gas is delivered into our intrastate pipelines and NGLs are delivered into our NGL pipelines to Lone Star.

  Our treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications.
- The Eagle Ford Gathering System consists of 30-inch and 42-inch natural gas gathering pipelines with over 1.4 Bcf/d of capacity originating in Dimmitt County, Texas, and extending to both our King Ranch gas plant in Kleberg County, Texas and Jackson plant in Jackson County, Texas. The Eagle Ford Gathering System includes four processing plants (Chisholm, Kenedy, Jackson and King Ranch) with aggregate capacity of 1,920 MMcf/d and one natural gas treating facility with capacity of 930 MMcf/d. Our Chisholm, Kenedy, Jackson and King Ranch processing plants are connected to our intrastate transportation pipeline systems for deliveries of residue gas and are also connected with our NGL pipelines for delivery of NGLs to Lone Star.

Ark-La-Tex Region:

- Our Northern Louisiana assets are comprised of several gathering systems in the Haynesville Shale with access to multiple markets through interconnects with several pipelines, including our Tiger Pipeline. Our Northern Louisiana assets include the Bistineau, Creedence, and Tristate Systems, which collectively include three natural gas treating facilities, with aggregate capacity of 1,186 MMcf/d.
- Our PennTex Midstream System is primarily located in Lincoln Parish, Louisiana, and consists of the Lincoln Parish plant, a 200 MMcf/d design-capacity cryogenic natural gas processing plant located near Arcadia, Louisiana, the Mt. Olive plant, a 200 MMcf/d design-capacity cryogenic natural gas processing plant located near Ruston, Louisiana, with on-site liquids handling facilities for inlet gas; a 35-mile rich gas gathering system that provides producers with access to our processing plants and third-party processing capacity; a 15-mile residue gas pipeline that provides market access for natural gas from our processing plants, including connections with pipelines that provide access to the Perryville Hub and other markets in the

Gulf Coast region; and a 40-mile NGL pipeline that provides connections to the Mont Belvieu market for NGLs produced from our processing plants.

- The Ark-La-Tex assets gather, compress, treat and dehydrate natural gas in several parishes in 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. Collectively, the eight natural gas processing facilities (Dubach, Dubberly, Lisbon, Salem, Elm Grove, Minden, Ada and Brookeland) have an aggregate capacity of 1,025 MMcf/d.

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

North Central Texas Region:

The North Central Texas System is an integrated system located in four counties in North Central Texas that gathers, compresses, treats, processes and transports natural gas from the Barnett and Woodford Shales. Our North Central Texas assets include our Godley and Crescent plants, which process rich gas produced from the Barnett Shale and STACK play, with aggregate capacity of 740 MMcf/d and aggregate treating capacity of 1,120 MMcf/d. The Godley plant is integrated with the ET Fuel System.

Permian Region:

The Permian Basin Gathering System offers wellhead-to-market services to producers in eleven counties in West Texas, as well as two counties in New Mexico which surround the Waha Hub, one of Texas's developing NGL-rich natural gas market areas. As a result of the proximity of our system to the Waha Hub, the Waha Gathering System has a variety of market outlets for the natural gas that we gather and process, including several major interstate and intrastate pipelines serving California, the mid-continent region of the United States and Texas natural gas markets. The NGL market outlets includes Lone Star's liquids pipelines. The Permian Basin Gathering System includes ten processing facilities (Waha, Coyanosa, Red Bluff, Halley, Jal, Keyston, Tippet, Orla, Panther and Rebel) with an aggregate processing capacity of 1,418 MMcf/d, treating capacity of 1,580 MMcf/d, and one natural gas conditioning facility with aggregate capacity of 200 MMcf/d.

We own a 50% membership interest in Mi Vida JV, a joint venture which owns a 200 MMcf/d cryogenic processing plant in West Texas. We operate the plant and related facilities on behalf of Mi Vida JV.

We own a 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGL-rich Bone Spring and Avalon Shale formations in West Texas. The joint venture owns a 25 MMcf/d refrigeration plant and a 125 MMcf/d cryogenic processing plant.

Mid-Continent Region:

The 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. Our Mid-Continent assets are extensive systems that gather, compress and dehydrate low-pressure gas. The Mid-Continent Systems include fourteen natural gas processing facilities (Mocane, Beaver, Antelope Hills, Woodall, Wheeler, Sunray, Hemphill, Phoenix, Hamlin, Spearman, Red Deer, Lefors, Cargray and Gray) with an aggregate capacity of 885 MMcf/d and one natural gas treating facility with aggregate capacity of 20 MMcf/d.

We operate our Mid-Continent 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.

We also own 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.

Eastern Region:

The Eastern Region assets are located in nine counties in Pennsylvania, three counties in Ohio, three counties in West Virginia, and gather natural gas from the Marcellus and Utica basins. Our Eastern Region assets include approximately 500 miles of natural gas gathering pipeline, natural gas trunklines, fresh-water pipelines, and nine gathering and processing systems. The fresh water pipeline system and Ohio gathering assets are held by jointly-owned entities.

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

We and Traverse ORS LLC, a subsidiary of Traverse Midstream Partners LLC, own a 75% and 25% membership interest, respectively, in the ORS joint venture. On behalf of ORS, we operate its Ohio Utica River System (the “ORS System”), which consists of 47 miles of 36-inch and 13 miles of 30-inch gathering trunklines that delivers up to 2.1 Bcf/d to Rockies Express Pipeline (“REX”), Texas Eastern Transmission, and others.

NGL and Refined Products Transportation and Services

The following details our assets in the NGL and refined products transportation and services segment:

Description of Assets	Miles of Liquids Pipeline	Pipeline Throughput Capacity (Bbls/d)	NGL Fractionation / Processing Capacity (Bbls/d)	Working Storage Capacity (Bbls)
Liquids Pipelines:				
Lone Star Express	532	507,000	—	—
West Texas Gateway Pipeline	570	240,000	—	—
Legacy Sunoco Logistics NGL pipelines	900	**(2)		
Legacy Sunoco Logistics refined products pipelines	1,800	**(2)		
Other NGL Pipelines	356	691,000	—	—
Liquids Fractionation and Services Facilities:				
Mont Belvieu Facilities	185	42,000	520,000	50,000,000
Sea Robin Processing Plant[1]	—	—	26,000	—
Refinery Services[1]	100	—	25,000	—
Hattiesburg Storage Facilities	—	—	—	3,000,000
NGLs Terminals:				
Nederland	—	—	—	1,000,000
Marcus Hook Industrial Complex	—	—	—	3,000,000
Inkster	—	—	—	1,000,000
Refined Products Terminals (2)				

(1) Additionally, the Sea Robin Processing Plant and Refinery Services have residue capacities of 850 MMcf/d and 54 MMcf/d, respectively.

(2) See description of the legacy Sunoco Logistics assets below.

The following information describes our principal NGL and refined products transportation and services assets:

- The Lone Star Express System is an intrastate NGL pipeline consisting of 24-inch and 30-inch long-haul transportation pipeline that delivers mixed NGLs from processing plants in the Permian Basin, the Barnett Shale, and from East Texas to the Mont Belvieu NGL storage facility.
- The West Texas Gateway Pipeline transports NGLs produced in the Permian and Delaware Basins and the Eagle Ford Shale to Mont Belvieu, Texas.
- Legacy Sunoco Logistics NGL pipelines, including:
    - The Mariner East pipeline transports NGLs from the Marcellus and Utica Shales areas in Western Pennsylvania, West Virginia and Eastern Ohio to destinations in Pennsylvania, including our Marcus Hook Industrial Complex on the Delaware River, where they are processed, stored and distributed to local, domestic and waterborne markets. The first phase of the project, referred to as Mariner East 1, consisted of interstate and intrastate propane and ethane service and commenced operations in the fourth quarter of 2014 and the first quarter of 2016, respectively. The second phase of the project, referred to as Mariner East 2, will expand the total takeaway capacity to 345,000 Bbls/d for interstate and intrastate propane, ethane and butane service, and is expected to commence operations in the third quarter of 2017.

  - The Mariner South pipeline is part of a joint project with Lone Star to deliver export-grade propane and butane products from Lone Star's Mont Belvieu, Texas storage and fractionation complex to Sunoco Logistics' marine terminal in Nederland, Texas. The pipeline has a capacity of approximately 200,000 Bbls/d and can be scaled depending on shipper interest.

  - The Mariner West pipeline provides transportation of ethane products from the Marcellus shale processing and fractionating areas in Houston, Texas and Pennsylvania to Marysville, Michigan and the Canadian border. Mariner West commenced operations in the fourth quarter 2013, with capacity to transport approximately 50,000 Bbls/d of NGLs and other products.

- Legacy Sunoco Logistics refined products pipelines include approximately 1,800 miles of refined products pipelines in several regions of the United States. The pipelines primarily provide transportation in the northeast, midwest, and southwest United States markets. These operations include Sunoco Logistics' controlling financial interest in Inland Corporation ("Inland"). The mix of products delivered varies seasonally, with gasoline demand peaking during the summer months, and demand for heating oil and other distillate fuels peaking in the winter. In addition, weather conditions in the areas served by the refined products pipelines affect both the demand for, and the mix of, the refined products delivered through the pipelines, although historically, any overall impact on the total volume shipped has been short-term. The products transported in these pipelines include multiple grades of gasoline, and middle distillates, such as heating oil, diesel and jet fuel. Rates for shipments on these product pipelines are regulated by the FERC and other state regulatory agencies, as applicable.
- Other NGL pipelines include the 127-mile Justice pipeline with capacity of 375,000 Bbls/d, the 45-mile Freedom pipeline with a capacity of 56,000 Bbls/d, the 15-mile Spirit pipeline with a capacity of 20,000 Bbls/d, the 82-mile Rio Bravo crude oil pipeline with a capacity of 100,000 Bbls/d and a 50% interest in the 87-mile Liberty pipeline with a capacity of 140,000 Bbls/d.
- Our Mont Belvieu storage facility is an integrated liquids storage facility with over 50 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.
- Our Mont Belvieu fractionators handle NGLs delivered from several sources, including the Lone Star Express pipeline and the Justice pipeline.
- 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.
- Refinery Services consists of a refinery off-gas processing and O-grade NGL fractionation complex located along the Mississippi River refinery corridor in southern Louisiana that cryogenically processes refinery off-gas and fractionates the O-grade NGL stream into its higher value components. The O-grade fractionator, located in Geismar, Louisiana, is connected by approximately 100 miles of pipeline to the Chalmette processing plant, which has a processing capacity of 54 MMcf/d.
- The Hattiesburg storage facility is an integrated liquids storage facility with approximately 3 million Bbls of salt dome capacity, providing 100% fee-based cash flows.
- The Nederland terminal, in addition to crude oil activities, also provides approximately 1 million barrels of storage and distribution services for NGLs in connection with the Mariner South pipeline, which provides transportation of propane and butane products from the Mont Belvieu region to the Nederland terminal, where such products can be delivered via ship.
- The Marcus Hook Industrial Complex includes terminalling and storage assets, with a capacity of approximately 3 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 NGLs storage and terminalling services to both affiliates and third-party customers, the Marcus Hook Industrial Complex currently serves as an off-take outlet for the Mariner East 1 pipeline, and will provide similar off-take capabilities for the Mariner East 2 pipeline when it commences operations.
- The Inkster terminal, located near Detroit, Michigan, consists of multiple salt caverns with a total storage capacity of approximately 1 million barrels of NGLs. We use the Inkster terminal's storage in connection with the Toledo North 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 unloading rack.
- We have approximately 40 refined products terminals with an aggregate storage capacity of approximately 8 million barrels that facilitate the movement of refined products to or from storage or transportation systems, such as a pipeline, to other transportation systems, such as trucks or other pipelines. Each facility typically consists of multiple storage tanks and is equipped with automated truck loading equipment that is operational 24 hours a day.

- In addition to crude oil service, the Eagle Point terminal can accommodate three marine vessels (ships or barges) to receive and deliver refined products to outbound ships and barges. The tank farm has a total active refined products storage capacity of approximately 6 million barrels, and provides customers with access to the facility via barge and pipeline. The terminal can deliver via barge, truck or pipeline, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage.

- The Marcus Hook Industrial Complex can receive refined products via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck. The terminal has a total active refined products storage capacity of approximately 2 million barrels.

- The Marcus Hook Tank Farm has a total refined products storage capacity of approximately 2 million barrels of refined products storage. The tank farm historically served Sunoco Inc.'s Marcus Hook refinery and generated revenue from the related throughput and storage. In 2012, the main processing units at the refinery were idled in connection with Sunoco Inc.'s exit from its refining business. The terminal continues to receive and deliver refined products via pipeline and now primarily provides terminalling services to support movements on Sunoco Logistics' refined products pipelines.

Crude Oil Transportation and Services

The following details our assets in the crude oil transportation and services segment:

Our crude oil operations consist of an integrated set of pipeline, terminalling, and acquisition and marketing assets that service the movement of crude oil from producers to end-user markets.

Crude Oil Pipelines

Our crude oil pipelines consist of approximately 6,100 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States, including wholly-owned interests in West Texas Gulf and Permian Express Terminal LLC ("PET"), and a controlling financial interest in Mid-Valley Pipeline Company ("Mid-Valley"). Additionally, we have equity ownership interests in two crude oil pipelines. Our crude oil pipelines provide access to several trading hubs, including the largest trading hub for crude oil in the United States located in Cushing, Oklahoma, and other trading hubs located in Midland, Colorado City and Longview, Texas. Our crude oil pipelines also deliver to and connect with other pipelines that deliver crude oil to a number of refineries.

- *Southwest United States Pipelines.* The Southwest pipelines include crude oil trunk pipelines and crude oil gathering pipelines in Texas and Oklahoma. This includes the Permian Express 2 pipeline project which provides takeaway capacity from the Permian Basin, with origins in multiple locations in Western Texas: Midland, Garden City and Colorado City. Our fourth quarter 2016 acquisition of a West Texas crude oil system from Vitol Inc. and the remaining ownership interest in PET facilitates connection of its Permian Express 2 pipeline to terminal assets in Midland and Garden City, Texas.

  In the third quarter 2016, we commenced operations on the Delaware Basin Extension and Permian Longview and Louisiana Extension pipeline projects. The Delaware Basin Extension pipeline project provides shippers with new takeaway capacity from the rapidly growing Delaware Basin area in New Mexico and West Texas to Midland, Texas. The project has initial capacity to transport approximately 100,000 Bbls/d. The Permian Longview and Louisiana Extension pipeline project provides takeaway capacity for approximately 100,000 Bbls/d additional out of the Permian Basin at Midland, Texas to be transported to the Longview, Texas area as well as destinations in Louisiana utilizing a combination of our proprietary crude oil system as well as third-party pipelines.

  We own and operate crude oil pipeline and gathering systems in Oklahoma. We have the ability to deliver substantially all of the crude oil gathered on our Oklahoma system to Cushing. We are one of the largest purchasers of crude oil from producers in the state, and its crude oil acquisition and marketing activities business is the primary shipper on its Oklahoma crude oil system.

- *Midwest United States Pipelines.* We own a controlling financial interest in the Mid-Valley pipeline system which 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.

  In addition, we own a 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 Petroleum Corporation's Samaria, Michigan tank farm, which supplies its refinery in Detroit, Michigan.

Crude Oil Terminals

- *Nederland.* 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 26 million barrels in approximately 150 above ground storage tanks with individual capacities of up to 660,000 Bbls.

  The Nederland terminal can receive crude oil at each of its five ship docks and four 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 395 million barrels.

  The Nederland Terminal can deliver crude oil and other petroleum products via pipeline, barge and ship. The terminal has two ship docks and three barge berths that are capable of delivering crude oils for international transport. In total, the terminal is capable of delivering over 2 million Bbls/d of crude oil to our crude oil pipelines or a number of third-party pipelines including the DOE. The Nederland terminal generates crude oil revenues primarily by providing term or spot storage services and throughput capabilities to a number of customers.

- *Fort Mifflin.* 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 Bbls. 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 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 under a joint venture with Sunoco, Inc. 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.

- *Eagle Point.* 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 1 million barrels and can receive crude oil via barge and rail and deliver via barge, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage.

- *Midland.* The Midland terminal is located in Midland, Texas and was acquired in November 2016 from Vitol. The facility includes approximately 2 million barrels of crude oil storage, a combined 14 lanes of truck loading and unloading, and will provide access to the Permian Express 2 transportation system.

Crude Oil Acquisition and Marketing

Our 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 our assets, which include approximately 370 crude oil transport trucks and approximately 150 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 both 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 using the pipelines, terminals and trucks or, when necessary or cost effective, pipelines, terminals 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.

In November 2016, Sunoco Logistics purchased a crude oil acquisition and marketing business from Vitol, with operations based in the Permian Basin, Texas. Included in the acquisition was a significant acreage dedication from an investment-grade Permian producer.

All Other

The following details our assets in the all other segment.

Equity Method Investments

- *Sunoco LP.* We have an equity method investment in limited partnership units of Sunoco LP consisting of 43.5 million units, representing 44.3% of Sunoco LP's total outstanding common units.
- *PES.* We have a non-controlling interest in PES, comprising 33% of PES' outstanding common units.

Contract Services Operations

We own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management. Our contract treating services are primarily located in Texas, Louisiana and Arkansas.

Compression

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

We own 100% of the membership interests of ETG, which owns all of the partnership interests of ETT. ETT provides compression services to customers engaged in the transportation of natural gas, including our other segments.

Natural Resources Operations

Our Natural Resources operations primarily involve the management and leasing of coal properties and the subsequent collection of royalties. We also earn 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, 2016, we owned or controlled approximately 772 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 in the Illinois Basin, properties in southern Illinois, Indiana, and western Kentucky and as the operator of end-user coal handling facilities. Our subsidiary, Materials Handling Solutions, LLC, owns and operates facilities for industrial customers on a fee basis. During 2014, our coal reserves located in the San Juan basin were depleted and our associated coal royalties revenues ceased.

Liquefaction Project

LCL, an entity whose parent is 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 440 acres of land, of which 80 acres are owned by Lake Charles LNG and the remaining acres are to be leased by LCL under a long-term lease from the Lake Charles Harbor and Terminal District.

As currently provided in the Project Development Agreement, 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. In the event that each of LCL and BG elect to make an affirmative FID, construction of the liquefaction project would commence promptly thereafter, and the first train would be expected to be placed in service about four years later.

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 the Non-FTA Authorization was granted in July 2016.

We have received our 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.

Business Strategy

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Environmental Matters

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Employees

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

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, and amendments to these 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.

PART II

ITEM 6. SELECTED FINANCIAL DATA

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

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Statement of Operations Data:					
Total revenues	$ 21,827	$ 34,292	$ 55,475	$ 48,335	$ 16,964
Operating income	1,802	2,259	2,443	1,619	1,425
Income from continuing operations	624	1,521	1,235	713	1,754
Basic income (loss) from continuing operations per Common Unit	(1.37)	(0.06)	1.05	(0.15)	3.29
Diluted income (loss) from continuing operations per Common Unit	(1.37)	(0.07)	1.05	(0.15)	3.27
Cash distributions per unit	2.81	2.77	2.57	2.41	2.39
Balance Sheet Data (at period end):					
Total assets	70,191	65,173	62,518	49,900	48,394
Long-term debt, less current maturities	31,741	28,553	24,831	19,761	17,599
Total equity	26,527	27,031	25,311	18,694	19,982
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis)	368	485	444	391	347
Growth (accrual basis)	5,442	7,682	5,050	2,936	3,186
Cash paid for acquisitions	1,227	804	2,367	1,737	1,364

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

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

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

References to "we," "us," "our," the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries.

Overview

The primary activities and operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger, CrossCountry, ETC MEP and ET Rover. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems.
- Liquids operations, including NGL transportation, storage and fractionation services and refined products transportation.
- Crude oil transportation, terminalling services and acquisition and marketing activities.

Recent Developments

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

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 businesses through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain strategic operations and businesses or assets as demonstrated by our recent acquisitions and organic growth projects. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.

During the past several years, we have been successful in completing several transactions that have significantly increased our distributable cash flow. We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional distributable cash flow to our Partnership for years to come. Lastly, we have established and executed on cost control measures to drive cost savings across our operations to generate additional distributable cash flow.

Our principal operations as of December 31, 2016 included the following segments:

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

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

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

  In addition, we use financial derivatives to lock in price differentials between market hubs connected to our assets on a portion of our intrastate transportation system's unreserved capacity. Gains and losses on these financial derivatives are dependent on price differentials at market locations, primarily points in West Texas and East Texas. We account for these derivatives using mark-to-market accounting, and the change in the value of these derivatives is recorded in earnings. During the fourth quarter of 2011, we began using derivatives for trading purposes.

- Interstate transportation and storage – The majority of our interstate transportation and storage revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Tiger, FEP, Transwestern, Panhandle, MEP and Gulf States shippers have made long-term commitments to pay reservation charges for the firm capacity reserved for their use. In addition to reservation revenues, additional revenue sources include interruptible transportation charges as well as usage rates and overrun rates paid by firm shippers based on their actual capacity usage.

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

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

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

- NGL and refined products transportation and services – 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. Revenues are also generated by charging fees for terminalling services for NGLs and refined products and by acquiring and marketing NGLs and refined products. Generally, NGL and refined products purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.

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

  Our refined products acquisition and marketing activities include the acquisition, marketing and selling of bulk refined products such as gasoline products and distillates. These activities utilize our refined products pipeline and terminal assets, as well as third-party assets and facilities. The operating results of our refined products acquisition and marketing activities are dependent on our ability to execute sales in excess of the aggregate cost, and therefore we structure our acquisition and marketing operations to optimize the sources and timing of purchases and minimize the transportation and storage costs. In order to manage exposure to volatility in refined products prices, our policy is to (i) only purchase products for which sales contracts have been executed or for which ready markets exist, (ii) structure sales contracts so that price fluctuations do not materially impact the margins earned, and (iii) not acquire and hold physical inventory, futures contracts or other derivative instruments for the purpose of speculating on commodity price changes. However, we do utilize a hedge program involving swaps, futures and other derivative instruments to mitigate the risk associated with unfavorable market movements in the price of refined products. These derivative contracts act as a hedging mechanism against the volatility of prices.

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

- Crude oil transportation and services – Revenues are generated by charging tariffs for transporting crude oil through our pipelines as well as by charging fees for terminalling services for at our facilities. Revenues are also generated by acquiring and marketing crude oil. Generally, crude oil purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.

Trends and Outlook

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Results of Operations

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, 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, losses on extinguishments of debt 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.

When presented on a consolidated basis, Adjusted EBITDA is a non-GAAP measure. Although we include Segment Adjusted EBITDA in this report, we have not included an analysis of the consolidated measure, Adjusted EBITDA. We have included a total of Segment Adjusted EBITDA for all segments, which is reconciled to the GAAP measure of net income in the consolidated results sections that follow.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Consolidated Results

	Years Ended December 31,		
	2016	2015	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 613	$ 543	$ 70
Interstate transportation and storage	1,117	1,155	(38)
Midstream	1,133	1,237	(104)
NGL and refined products transportation and services	1,483	1,225	258
Crude oil transportation and services	719	671	48
All other	540	883	(343)
Total	5,605	5,714	(109)
Depreciation, depletion and amortization	(1,986)	(1,929)	(57)
Interest expense, net	(1,317)	(1,291)	(26)
Gains on acquisitions	83	—	83
Impairment losses	(813)	(339)	(474)
Losses on interest rate derivatives	(12)	(18)	6
Non-cash unit-based compensation expense	(80)	(79)	(1)
Unrealized losses on commodity risk management activities	(131)	(65)	(66)
Inventory valuation adjustments	170	(104)	274
Losses on extinguishments of debt	—	(43)	43
Adjusted EBITDA related to unconsolidated affiliates	(946)	(937)	(9)
Equity in earnings of unconsolidated affiliates	59	469	(410)
Impairment of investment in an unconsolidated affiliate	(308)	—	(308)
Other, net	114	20	94
Income before income tax benefit	438	1,398	(960)
Income tax benefit	186	123	63
Net income	$ 624	$ 1,521	$ (897)

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased primarily due to increases from assets recently placed in service, partially offset by a decrease of $191 million related to the deconsolidation of Sunoco, LLC and the legacy Sunoco, Inc. retail business.

Gains on Acquisitions. Gains on acquisitions include gains of $83 million in connection with recent acquisitions during 2016, including $41 million related to Sunoco Logistics' acquisition of the remaining interest in SunVit.

Impairment Losses. In 2016, we recorded goodwill impairments of $638 million in the interstate transportation and storage segment and $32 million in the midstream segment. These goodwill impairments were primarily due to decreases in projected future revenues and cash flows driven by declines in commodity prices and changes in the markets that these assets serve. In addition, impairment losses for 2016 also include a $133 million impairment to property, plant and equipment in the interstate transportation and storage segment due to a decrease in projected future cash flows as well as a $10 million impairment to property, plant and equipment in the midstream segment. In 2015, we recorded goodwill impairments of (i) $99 million related to Transwestern due primarily to the market declines in current and expected future commodity prices in the fourth quarter of 2015, (ii) $106 million related to Lone Star Refinery Services due primarily to changes in assumptions related to potential future revenues as well as the market declines in current and expected future commodity prices, (iii) $110 million of fixed asset impairments related to Lone Star NGL Refinery Services primarily due to the economic obsolescence identified as a result of low utilization and expected decrease in future cash flows, and (iv) $24 million of intangible asset impairments related to Lone Star NGL Refinery Services primarily due to the economic obsolescence identified as a result of expected decrease in future cash flows.

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 years ended December 31, 2016 and 2015 resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value.

Unrealized Losses on Commodity Risk Management Activities. See discussion of the unrealized gains (losses) on commodity risk management activities included in “Segment Operating Results” below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco Logistics’ crude oil, NGLs and refined products inventories as a result of commodity price changes between periods.

Adjusted EBITDA Related to Unconsolidated Affiliates and *Equity in Earnings of Unconsolidated Affiliates.* See additional information in “Supplemental Information on Unconsolidated Affiliates” and “Segment Operation Results” below.

Impairment of Investment in an Unconsolidated Affiliate. In 2016, the Partnership impaired its investment in MEP and recorded a non-cash impairment loss of $308 million based on commercial discussions with current and potential shippers on MEP regarding the outlook for long-term transportation contract rates.

Other, net. Other, net in 2016 and 2015 primarily includes amortization of regulatory assets and other income and expense amounts.

Income Tax Benefit. For the years ended December 31, 2016 and 2015, the Partnership recorded an income tax benefit due to pre-tax losses at its corporate subsidiaries. The year ended December 31, 2015 also reflected a benefit of $24 million of net state tax benefit attributable to statutory state rate changes resulting from the Regency Merger and sale of Susser to Sunoco LP, as well as a favorable impact of $11 million due to a reduction in the statutory Texas franchise tax rate which was enacted by the Texas legislature during the second quarter of 2015.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2016	Years Ended December 31, 2015	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 102	$ 97	$ 5
FEP	51	55	(4)
PES	(26)	52	(78)
MEP	40	45	(5)
HPC	31	32	(1)
AmeriGas	14	(3)	17
Sunoco, LLC	—	(10)	10
Sunoco LP[1]	(211)	202	(413)
Other	58	(1)	59
Total equity in earnings of unconsolidated affiliates	$ 59	$ 469	$ (410)
Adjusted EBITDA related to unconsolidated affiliates[2]:			
Citrus	$ 329	$ 315	$ 14
FEP	75	75	—
PES	10	86	(76)
MEP	90	96	(6)
HPC	61	61	—
Sunoco, LLC	—	91	(91)
Sunoco LP	271	137	134
Other	110	76	34
Total Adjusted EBITDA related to unconsolidated affiliates	$ 946	$ 937	$ 9
Distributions received from unconsolidated affiliates:			
Citrus	$ 144	$ 182	$ (38)
FEP	65	69	(4)
PES	—	78	(78)
MEP	74	80	(6)
HPC	51	52	(1)
AmeriGas	12	11	1
Sunoco LP	138	39	99
Other	57	53	4
Total distributions received from unconsolidated affiliates	$ 541	$ 564	$ (23)

(1) For the year ended December 31, 2016, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by Sunoco LP, which reduced the Partnership's equity in earnings by $277 million.

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

Segment Operating Results

Our reportable segments are discussed below. "All other" includes our compression operations, our investment in AmeriGas, our approximate 33% non-operating interest in PES, our investment in Coal Handling and our natural gas marketing operations.

Additionally, due to the transfer of the general partner interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016, the Partnership's retail marketing segment has been deconsolidated, and the segment results now reflect an equity method investment in limited partnership units of Sunoco LP. As of December 31, 2016, the Partnership's interest in Sunoco LP common units consisted of 43.5 million units, representing 44.3% of Sunoco LP's total outstanding common units, and is reflected in the all other segment.

We evaluate segment performance based on Segment Adjusted EBITDA, which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments.

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

- *Segment margin, operating expenses,* and *selling, general and administrative expenses*. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.
- *Unrealized gains or losses on commodity risk management activities* and *inventory valuation adjustments*. These are the unrealized amounts that are included in cost of products sold to calculate segment margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.
- *Non-cash compensation expense*. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative expenses. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.
- *Adjusted EBITDA related to unconsolidated affiliates*. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA.

In the following analysis of segment operating results, a measure of segment margin is reported for segments with sales revenues. Segment Margin is a non-GAAP financial measure and is presented herein to assist in the analysis of segment operating results and particularly to facilitate an understanding of the impacts that changes in sales revenues have on the segment performance measure of Segment Adjusted EBITDA. Segment Margin is similar to the GAAP measure of gross margin, except that Segment Margin excludes charges for depreciation, depletion and amortization.

In addition, for certain segments, the sections below include information on the components of Segment Margin by sales type, which components are included in order to provide additional disaggregated information to facilitate the analysis of Segment Margin and Segment Adjusted EBITDA. For example, these components include transportation margin, storage margin, and other margin. These components of Segment Margin are calculated consistent with the calculation of Segment Margin; therefore, these components also exclude charges for depreciation, depletion and amortization.

For additional information regarding our business segments, see "Item 1. Business" and Notes 1 and 15 to our consolidated financial statements.

Following is a reconciliation of Segment Margin to operating income, as reported in the Partnership's consolidated statements of operations:

	Years Ended December 31,	
	2016	2015
Segment Margin by segment:		
Intrastate transportation and storage	$ 716	$ 696
Interstate transportation and storage	969	1,025
Midstream	1,798	1,792
NGL and refined products transportation and services	1,944	1,660
Crude oil transportation and services	1,156	821
All other	330	1,745
Intersegment eliminations	(480)	(476)
Total Segment Margin	6,433	7,263
Less:		
Operating expenses	1,484	2,261
Depreciation, depletion and amortization	1,986	1,929
Selling, general and administrative	348	475
Impairment losses	813	339
Operating income	$ 1,802	$ 2,259

Intrastate Transportation and Storage

	Years Ended December 31,		
	2016	2015	Change
Natural gas transported (MMBtu/d)	8,257,611	8,426,818	(169,207)
Revenues	$ 2,613	$ 2,250	$ 363
Cost of products sold	1,897	1,554	343
Segment margin	716	696	20
Unrealized (gains) losses on commodity risk management activities	19	(26)	45
Operating expenses, excluding non-cash compensation expense	(162)	(163)	1
Selling, general and administrative expenses, excluding non-cash compensation expense	(22)	(25)	3
Adjusted EBITDA related to unconsolidated affiliates	61	61	—
Other	1	—	1
Segment Adjusted EBITDA	$ 613	$ 543	$ 70

Volumes. For the year ended December 31, 2016 compared to the prior year, transported volumes decreased primarily due to lower production volumes in the Barnett Shale region, partially offset by increased volumes related to significant new long-term transportation contracts, as well as the addition of a new short-haul transport pipeline delivering volumes into our Houston Pipeline system.

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

	Years Ended December 31,		
	2016	2015	Change
Transportation fees	$ 505	$ 502	$ 3
Natural gas sales and other	113	96	17
Retained fuel revenues	48	57	(9)
Storage margin, including fees	50	41	9
Total segment margin	$ 716	$ 696	$ 20

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $3 million in transportation fees, despite lower throughput volumes, due to fees from renegotiated and newly initiated fixed fee contracts primarily on our Houston Pipeline system;
- an increase of $34 million in natural gas sales (excluding changes in unrealized losses of $17 million) primarily due to higher realized gains from the buying and selling of gas along our system;
- a decrease of $9 million from the sale of retained fuel, primarily due to lower market prices and lower volumes. The average spot price at the Houston Ship Channel location decreased 5% for the year ended December 31, 2016 compared to the prior year;
- an increase of $37 million in storage margin (excluding net changes in unrealized amounts of $28 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below; and
- a decrease of $3 million in general and administrative expenses primarily due to lower legal fees and insurance costs, as well as allocations between segments.

Storage margin was comprised of the following:

	Years Ended December 31,		
	2016	2015	Change
Withdrawals from storage natural gas inventory (MMBtu)	38,905,000	15,782,500	23,122,500
Realized margin on natural gas inventory transactions	$ 36	$ (2)	$ 38
Fair value inventory adjustments	76	4	72
Unrealized (gains) losses on derivatives	(87)	12	(99)
Margin recognized on natural gas inventory, including related derivatives	25	14	11
Revenues from fee-based storage	25	27	(2)
Total storage margin	$ 50	$ 41	$ 9

The changes in storage margin were primarily driven by the timing of withdrawals and sales of natural gas from our Bammel storage cavern, as well as the timing of settlement of related derivative hedging contracts.

Interstate Transportation and Storage

	Years Ended December 31,		
	2016	2015	Change
Natural gas transported (MMBtu/d)	5,475,948	6,074,282	(598,334)
Natural gas sold (MMBtu/d)	18,842	17,340	1,502
Revenues	$ 969	$ 1,025	$ (56)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(302)	(304)	2
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(47)	(52)	5
Adjusted EBITDA related to unconsolidated affiliates	494	486	8
Other	3	—	3
Segment Adjusted EBITDA	$ 1,117	$ 1,155	$ (38)

Volumes. For the year ended December 31, 2016 compared to the prior year, transported volumes decreased 423,564 MMBtu/d on the Trunkline pipeline due to the transfer of one of the pipelines at Trunkline which was repurposed from natural gas service to crude oil service and lower utilization resulting from lower customer demand. Transported volumes decreased 82,018 MMBtu/d on the Transwestern pipe line due to milder weather in the West and decreased 76,373 MMBtu/d on the Sea Robin pipeline due to reduced supply as a result of producer system maintenance and overall lower production.

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $26 million in revenues due to contract restructuring on the Tiger pipeline, a decrease of $17 million due to lower reservation revenues on the Panhandle and Trunkline pipelines from capacity sold at lower rates and lower sales of capacity in the Phoenix and San Juan areas on the Transwestern pipeline, a decrease of $14 million due to the transfer of one of the Trunkline pipelines which was repurposed from natural gas service to crude oil service, a decrease of $11 million due to the expiration of a transportation rate schedule on the Transwestern pipeline, and a decrease of $10 million on the Sea Robin pipeline due to declines in production and third-party maintenance. These decreases were partially offset by higher reservation revenues on the Transwestern pipeline of $18 million, primarily from a growth project, and higher parking revenues of $9 million, primarily on the Panhandle and Trunkline pipelines; partially offset by
- an increase of $8 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to higher margins from sales of additional capacity on Citrus of $6 million and lower operating expenses of $5 million, offset by lower margins on the Midcontinent Express pipeline of $4 million due to a customer bankruptcy;
- a decrease of $2 million in operating expenses primarily due to lower maintenance project costs of $5 million and lower allocated costs of $3 million. These decreases were partially offset by an increase of $7 million in ad valorem tax expense due to higher current year assessments of $2 million and a prior period credit and settlement of ad valorem taxes in 2015 of $5 million;
- a decrease of $5 million in selling, general and administrative expenses primarily due to $5 million in lower allocated costs; and
- an increase of $3 million in other primarily due to the tax gross-up associated with reimbursable projects on the Transwestern and Panhandle pipelines.

Table of Contents

Midstream

	Years Ended December 31,		
	2016	2015	Change
Gathered volumes (MMBtu/d)	9,813,660	9,981,212	(167,552)
NGLs produced (Bbls/d)	437,730	406,149	31,581
Equity NGLs (Bbls/d)	31,131	28,493	2,638
Revenues	$ 5,179	$ 5,056	$ 123
Cost of products sold	3,381	3,264	117
Segment margin	1,798	1,792	6
Unrealized losses on commodity risk management activities	15	82	(67)
Operating expenses, excluding non-cash compensation expense	(621)	(616)	(5)
Selling, general and administrative expenses, excluding non-cash compensation expense	(84)	(44)	(40)
Adjusted EBITDA related to unconsolidated affiliates	24	20	4
Other	1	3	(2)
Segment Adjusted EBITDA	$ 1,133	$ 1,237	$ (104)

Volumes. Gathered volumes decreased during the year ended December 31, 2016 compared to the prior year primarily due to declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions, partially offset by increases in the Permian region and the impact of recent acquisitions, including PennTex. NGL production increased due to increased gathering and processing capacities in the Permian region, partially offset by declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions.

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

	Years Ended December 31,		
	2016	2015	Change
Gathering and processing fee-based revenues	$ 1,554	$ 1,570	$ (16)
Non fee-based contracts and processing	244	222	22
Total segment margin	$ 1,798	$ 1,792	$ 6

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net impacts of the following:

- a decrease of $16 million in fee-based margin due to volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions, partially offset by increased gathering and processing volumes in the Permian region and the impact of recent acquisitions, including PennTex and the King Ranch assets;
- an increase of $40 million in general and administrative expenses primarily due to costs associated with the acquisition of PennTex and changes in capitalized overhead and accruals;
- an increase of $5 million in operating expenses primarily due to the King Ranch acquisition in the second quarter of 2015 and assets recently placed in service in the Permian and Eagle Ford regions; and
- a decrease of $92 million (excluding unrealized gains of $67 million) in non fee-based margin due to lower benefit from settled derivatives used to hedge commodity margins; partially offset by
- an increase of $44 million in non fee-based margin due to volume increases in the Permian region, partially offset by volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions; and
- an increase of $3 million in non fee-based margin due to higher crude oil and NGL prices, partially offset by lower natural gas prices.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2016	2015	Change
Revenues	$ 6,535	$ 5,118	$ 1,417
Cost of products sold	4,591	3,458	1,133
Segment margin	1,944	1,660	284
Unrealized losses on commodity risk management activities	69	10	59
Operating expenses, excluding non-cash compensation expense	(520)	(469)	(51)
Selling, general and administrative expenses, excluding non-cash compensation expense	(56)	(55)	(1)
Inventory valuation adjustments	(22)	12	(34)
Adjusted EBITDA related to unconsolidated affiliates	67	67	—
Other	1	—	1
Segment Adjusted EBITDA	$ 1,483	$ 1,225	$ 258

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $209 million related to legacy ETP's NGLs operations, as follows:
  - an increase of $36 million in storage margin primarily due to increased volumes from our Mont Belvieu fractionators. Throughput volumes, on which we earn a fee in our storage assets, increased 34% resulting in an increase of $18 million year over year. We also realized an increase of $8 million due to increased demand for our leased storage capacity as a result of more favorable market conditions. Finally, we realized increased terminal fees and pipeline lease fees of $8 million, as well as increased blending gains of $2 million resulting from higher volumes during the 2016 period;
  - an increase of $80 million in legacy ETP's NGL transportation fees due to higher NGL transport volumes from all producing regions, with the Permian region being the most significant among them; and
  - an increase of $107 million in legacy ETP's NGL processing and fractionation margin (excluding an increase in unrealized losses of $11 million) primarily due to higher NGL volumes from all producing regions, as detailed in our transport fees explanation above. We placed approximately 118,000bbls/d of fractionation capacity in-service in 2016, allowing our Mont Belvieu fractionators to handle the significant increase in volumes from year to year. Additional barrels fractionated and an associated increase in blending gains at our fractionators resulted in a margin increase of $101 million. We delivered approximately 26% more barrels to our Mariner South LPG export terminal in the 2016 period, which resulted in an increase of $22 million in cargo loading fees and blending fees year over year. These gains were offset by an increase in storage fees paid of $2 million, and a decrease in margin from our refinery services segment of $3 million; partially offset by
  - a decrease of $24 million in other margin due to the timing of the withdrawal and sale of NGL component product inventory; and
  - an increase of $20 million in legacy ETP's operating expenses primarily due to increased costs associated with our third fractionator at Mont Belvieu and higher ad valorem expenses, partially offset by lower project related expenses. The remainder of the increase in operating expenses in the table above is related to legacy Sunoco Logistics' NGLs and refined products operations, the results of which are discussed separately below;
- an increase of $65 million in Adjusted EBITDA from legacy Sunoco Logistics' refined products operations driven primarily by improved operating results from refined products pipelines of $32 million, which benefited from higher volumes on Allegheny Access pipeline, and higher results from refined products acquisition and marketing activities of $21 million. Improved contributions from refined product joint venture interests of $6 million and higher earnings attributable to refined products terminals of $5 million also contributed to the increase; partially offset by
- a decrease in Adjusted EBITDA from legacy Sunoco Logistics' NGLs operations of $16 million, largely attributable to lower operating results from our NGLs acquisition and marketing activities of $106 million due to lower volumes and margins compared to the prior year. These factors were largely offset by increased volumes and fees from our Mariner NGLs projects of $90 million, which includes our NGLs pipelines and Marcus Hook and Nederland facilities.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2016	2015	Change
Revenue	$ 7,896	$ 9,267	$ (1,371)
Cost of products sold	6,740	8,446	(1,706)
Segment margin	1,156	821	335
Unrealized losses on commodity risk management activities	2	—	2
Operating expenses, excluding non-cash compensation expense	(247)	(245)	(2)
Selling, general and administrative expenses, excluding non-cash compensation expense	(58)	(53)	(5)
Inventory valuation adjustments	(148)	150	(298)
Adjusted EBITDA related to unconsolidated affiliates	14	(2)	16
Segment Adjusted EBITDA	$ 719	$ 671	$ 48

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $20 million in crude transport fees, primarily resulting from placing in-service the first phase of the Bayou Bridge pipeline in April 2016, and from placing crude gathering assets in West Texas in-service during the 2016 period; and
- an increase of $31 million from legacy Sunoco Logistics' crude oil operations, primarily due to improved results from our crude oil pipelines of $155 million which benefited from the expansion capital projects which commenced operations in 2016 and 2015, and the fourth quarter 2016 acquisition from Vitol, including the remaining interest in SunVit. Higher results from our crude oil terminals of $31 million, largely related to Nederland facility, and improved contributions from crude oil joint venture interests of $16 million also contributed to the increase. These positive factors were largely offset by a decrease in operating results from our crude oil acquisition and marketing activities of $166 million, which includes transportation and storage fees related to our crude oil pipelines and terminal facilities, due to lower crude oil differentials and decreased volumes compared to the prior year.

All Other

	Years Ended December 31,		
	2016	2015	Change
Revenue	$ 3,272	$ 15,774	$ (12,502)
Cost of products sold	2,942	14,029	(11,087)
Segment margin	330	1,745	(1,415)
Unrealized (gains) losses on commodity risk management activities	26	(1)	27
Operating expenses, excluding non-cash compensation expense	(79)	(896)	817
Selling, general and administrative expenses, excluding non-cash compensation expense	(86)	(254)	168
Adjusted EBITDA related to unconsolidated affiliates	286	313	(27)
Inventory valuation adjustments	—	(58)	58
Other	95	95	—
Elimination	(32)	(61)	29
Segment Adjusted EBITDA	$ 540	$ 883	$ (343)

Amounts reflected in our all other segment primarily include:

- our retail marketing operations prior to the transfer of the general partner interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016;

- our equity method investment in limited partnership units of Sunoco LP consisting of 43.5 million units, representing 44.3% of Sunoco LP's total outstanding common units;
- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities.

Segment Adjusted EBITDA. For the year ended December 31, 2016 compared to the prior year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $308 million due to the transfer and contribution of our retail marketing assets to Sunoco LP. The consolidated results of Sunoco LP are reflected in the results for All Other above through June 2015. Effective July 1, 2015, Sunoco LP was deconsolidated, and the results for All Other reflect Adjusted EBITDA related to unconsolidated affiliates for our limited partner interests in Sunoco LP. The impact of the deconsolidation of Sunoco LP reduced segment margin, operating expenses and selling, general and administrative expenses; the impact to Segment Adjusted EBITDA is offset by the incremental Adjusted EBITDA related to unconsolidated affiliates from our equity method investment in Sunoco LP subsequent to the deconsolidation; and
- a decrease of $76 million in Adjusted EBITDA related to our investment in PES.

ETP provides management services for ETE for which ETE has agreed to pay management fees to ETP of $95 million per year for the years ending December 31, 2016 and 2015. These fees were reflected in "Other" in the "All other" segment and for the years ended December 31, 2016 and 2015 were reflected as an offset to operating expenses of $32 million and selling, general and administrative expenses of $63 million in the consolidated statements of operations.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

Consolidated Results

	Years Ended December 31,		
	2015	2014	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 543	$ 559	$ (16)
Interstate transportation and storage	1,155	1,212	(57)
Midstream	1,237	1,318	(81)
NGL and refined products transportation and services	1,225	891	334
Crude oil transportation and services	671	671	—
All other	883	1,059	(176)
Total	5,714	5,710	4
Depreciation, depletion and amortization	(1,929)	(1,669)	(260)
Interest expense, net	(1,291)	(1,165)	(126)
Gain on sale of AmeriGas common units	—	177	(177)
Impairment losses	(339)	(370)	31
Losses on interest rate derivatives	(18)	(157)	139
Non-cash compensation expense	(79)	(68)	(11)
Unrealized gains (losses) on commodity risk management activities	(65)	112	(177)
Inventory valuation adjustments	(104)	(473)	369
Losses on extinguishments of debt	(43)	(25)	(18)
Adjusted EBITDA related to discontinued operations	—	(27)	27
Adjusted EBITDA related to unconsolidated affiliates	(937)	(748)	(189)
Equity in earnings of unconsolidated affiliates	469	332	137
Other, net	20	(36)	56
Income from continuing operations before income tax (expense) benefit	1,398	1,593	(195)
Income tax (expense) benefit from continuing operations	123	(358)	481
Income from continuing operations	1,521	1,235	286
Income from discontinued operations	—	64	(64)
Net income	$ 1,521	$ 1,299	$ 222

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions, including Regency's acquisitions in 2014.

Gain on Sale of AmeriGas Common Units. During the year ended December 31, 2014 we sold 18.9 million the AmeriGas common units that were originally received in connection with the contribution of our propane business to AmeriGas in January 2012. We recorded a gain based on the sale proceeds in excess of the carrying amount of the units sold. As of December 31, 2015, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

Impairment Losses. In 2015, we recorded goodwill impairments of (i) $99 million related to Transwestern due primarily to the market declines in current and expected future commodity prices in the fourth quarter of 2015, (ii) $106 million related to Lone Star Refinery Services due primarily to changes in assumptions related to potential future revenues as well as the market declines in current and expected future commodity prices, (iii) $110 million of fixed asset impairments related to Lone Star NGL Refinery Services primarily due to the economic obsolescence identified as a result of low utilization and expected decrease in future cash flows, and (iv) $24 million of intangible asset impairments related to Lone Star NGL Refinery Services primarily due to the economic obsolescence identified as a result of expected decrease in future cash flows. In 2014, a $370 million goodwill impairment was recorded related to the Permian Basin gathering and processing operations. The decline in estimated fair value of that reporting unit was primarily driven by a 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.

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 years ended December 31, 2015 and 2014 resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value.

Unrealized Gains (Losses) on Commodity Risk Management Activities. See discussion of the unrealized gains (losses) on commodity risk management activities included in “Segment Operating Results” below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco Logistics’ crude oil, NGLs and refined products inventories as a result of commodity price changes between periods.

Adjusted EBITDA Related to Discontinued Operations. In 2014, amounts were related to a marketing business that was sold effective April 1, 2014.

Adjusted EBITDA Related to Unconsolidated Affiliates and *Equity in Earnings of Unconsolidated Affiliates.* See additional information in “Supplemental Information on Unconsolidated Affiliates” and “Segment Operation Results” below.

Other, net. Other, net in 2015 and 2014 primarily includes amortization of regulatory assets and other income and expense amounts.

Income Tax (Expense) Benefit from Continuing Operations. For the year ended December 31, 2015, the Partnership’s effective income tax rate decreased from the prior year primarily due to lower earnings among the Partnership’s consolidated corporate subsidiaries. The year ended December 31, 2015 also reflected a benefit of $24 million of net state tax benefit attributable to statutory state rate changes resulting from the Regency Merger and sale of Susser to Sunoco LP, as well as a favorable impact of $11 million due to a reduction in the statutory Texas franchise tax rate which was enacted by the Texas legislature during the second quarter of 2015. For the year ended December 31, 2014, the Partnership’s income tax expense from continuing operations included unfavorable income tax adjustments of $87 million related to the Lake Charles LNG Transaction, which was treated as a sale for tax purposes.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2015	Years Ended December 31, 2014	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 97	$ 96	$ 1
FEP	55	55	—
PES	52	59	(7)
MEP	45	45	—
HPC	32	28	4
AmeriGas	(3)	21	(24)
Sunoco, LLC	(10)	—	(10)
Sunoco LP	202	—	202
Other	(1)	28	(29)
Total equity in earnings of unconsolidated affiliates	$ 469	$ 332	$ 137
Adjusted EBITDA related to unconsolidated affiliates[1]:			
Citrus	$ 315	$ 305	$ 10
FEP	75	75	—
PES	86	86	—
MEP	96	102	(6)
HPC	61	53	8
AmeriGas	—	56	(56)
Sunoco, LLC	91	—	91
Sunoco LP	137	—	137
Other	76	71	5
Total Adjusted EBITDA related to unconsolidated affiliates	$ 937	$ 748	$ 189
Distributions received from unconsolidated affiliates:			
Citrus	$ 182	$ 168	$ 14
FEP	69	70	(1)
PES	78	—	78
MEP	80	73	7
HPC	52	48	4
AmeriGas	11	28	(17)
Sunoco LP	39	—	39
Other	53	40	13
Total distributions received from unconsolidated affiliates	$ 564	$ 427	$ 137

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

Segment Operating Results

Following is a reconciliation of Segment Margin to operating income, as reported in the Partnership's consolidated statements of operations:

	Years Ended December 31, 2015	Years Ended December 31, 2014
Segment Margin by segment:		
Intrastate transportation and storage	$ 696	$ 688
Interstate transportation and storage	1,025	1,072
Midstream	1,792	1,930
NGL and refined products transportation and services	1,660	1,270
Crude oil transportation and services	821	736
All other	1,745	1,689
Intersegment eliminations	(476)	(324)
Total Segment Margin	7,263	7,061
Less:		
Operating expenses	2,261	2,059
Depreciation, depletion and amortization	1,929	1,669
Selling, general and administrative	475	520
Impairment losses	339	370
Operating income	$ 2,259	$ 2,443

Intrastate Transportation and Storage

	Years Ended December 31, 2015	Years Ended December 31, 2014	Change
Natural gas transported (MMBtu/d)	8,426,818	8,976,978	(550,160)
Revenues	$ 2,250	$ 2,857	$ (607)
Cost of products sold	1,554	2,169	(615)
Segment margin	696	688	8
Unrealized (gains) losses on commodity risk management activities	(26)	21	(47)
Operating expenses, excluding non-cash compensation expense	(163)	(180)	17
Selling, general and administrative, excluding non-cash compensation expense	(25)	(27)	2
Adjusted EBITDA related to unconsolidated affiliates	61	57	4
Segment Adjusted EBITDA	$ 543	$ 559	$ (16)

Volumes. For the year ended December 31, 2015 compared to the prior year, transported volumes decreased primarily due to lower production volume, primarily in the Barnett Sale region, partially offset by the increased volumes related to significant new long-term transportation contracts.

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

	Years Ended December 31, 2015	2014	Change
Transportation fees	$ 502	$ 466	$ 36
Natural gas sales and other	96	100	(4)
Retained fuel revenues	57	98	(41)
Storage margin, including fees	41	24	17
Total segment margin	$ 696	$ 688	$ 8

Segment Adjusted EBITDA. For the year ended December 31, 2015 compared to the prior year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $13 million in natural gas sales and other margin (excluding changes in unrealized gains of $8 million) primarily due to a $19 million decrease in commercial optimization activity as a result of weather driven gains in 2014 not reoccurring in 2015, a $4 million decrease from processing and producer marketing services on our Houston Pipeline System, offset by $10 million in lower losses due to volume adjustments across our pipeline system;
- a decrease of $17 million in storage margin, as discussed below; and
- a decrease of $44 million from the sale of retained fuel (excluding changes in unrealized gains of $3 million) due to significantly lower market prices. The average spot price at the Houston Ship Channel location for the year ended December 31, 2015 decreased by $1.76, or 41%, to $2.57 as compared to $4.32 for the prior year period; partially offset by
- an increase of $36 million in transportation fees margin primarily due to increased revenue from renegotiated and newly initiated long-term fixed capacity fee contracts on our Houston Pipeline system;
- a decrease of $2 million in selling, general and administrative expenses primarily due to lower employee-related costs;
- a decrease of $17 million in operating expenses primarily due to a decrease in fuel consumption expense driven by a decrease in fuel market prices.

Storage margin was comprised of the following:

	Years Ended December 31, 2015	2014	Change
Withdrawals from storage natural gas inventory (MMBtu)	15,782,500	37,197,510	(21,415,010)
Realized margin on natural gas inventory transactions	$ (2)	$ 17	$ (19)
Fair value inventory adjustments	4	(54)	58
Unrealized gains on derivatives	12	35	(23)
Margin recognized on natural gas inventory, including related derivatives	14	(2)	16
Revenues from fee-based storage	27	27	—
Other costs	—	(1)	1
Total storage margin	$ 41	$ 24	$ 17

The increase in storage margin was principally driven by the timing of the movement of market prices during both periods.

Interstate Transportation and Storage

	Years Ended December 31,		
	2015	2014	Change
Natural gas transported (MMBtu/d)	6,074,282	6,159,546	(85,264)
Natural gas sold (MMBtu/d)	17,340	16,470	870
Revenues	$ 1,025	$ 1,072	$ (47)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(304)	(291)	(13)
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(52)	(62)	10
Adjusted EBITDA related to unconsolidated affiliates	486	482	4
Other	—	11	(11)
Segment Adjusted EBITDA	$ 1,155	$ 1,212	$ (57)

Volumes. For the year ended December 31, 2015 compared to the prior year, transported volumes decreased 165,712 MMBtu/d on the Trunkline pipeline, primarily due to a managed contract roll off to facilitate the transfer of one of the pipelines that was taken out of service in advance of being repurposed from natural gas service to crude oil service. The decrease on the Trunkline pipeline was partially offset by an increase in volumes transported on the Tiger pipeline of 74,081 MMBtu/d, primarily due to increased deliveries to pipelines supporting the upper Midwest due to favorable market conditions and increased volumes on the Transwestern pipeline of 69,237 MMBtu/d due to sustained cooling demand in the Phoenix market and increased customer demand in the Texas intrastate market.

Segment Adjusted EBITDA. For the year ended December 31, 2015 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $47 million in revenues primarily due to lower gas parking service related revenues of approximately $19 million as a result of higher basis differentials in 2014 driven by the colder weather, $22 million and $7 million due to the expiration of a transportation rate schedule and lower sales of gas due to lower prices, respectively, on the Transwestern pipeline, and $15 million due to a managed contract roll off on the Trunkline pipeline to facilitate the transfer of one of the pipelines that was taken out of service in advance of being repurposed from natural gas service to crude oil service. These decreases were partially offset by sales of capacity at higher rates of $13 million on the Panhandle and Transwestern pipelines, as well as higher usage rates and volumes on the Transwestern pipeline;
- an increase of $13 million in operating expenses due to higher employee expenses of approximately $9 million due in part to lower capitalized costs and $3 million of higher ad valorem taxes primarily due to 2014 refunds associated with the settlement of litigation; and
- the recognition of an $11 million keep-whole payment received from our FEP joint venture, which is included in “Other” in 2014; offset by
- a decrease of $10 million in selling, general and administration expenses due to reduced franchise taxes of $3.5 million, state tax refund of $1.1 million, favorable insurance, primarily due to a $1.3 million OIL insurance rebate, and reduced corporate overhead allocations of $2.4 million.
- an increase of $4 million in adjusted EBITDA related to unconsolidated affiliates primarily due to increased earnings from Citrus as a result of the sale of additional capacity.

Midstream

	Years Ended December 31, 2015	Years Ended December 31, 2014	Change
Gathered volumes (MMBtu/d):	9,981,212	8,079,109	1,902,103
NGLs produced (Bbls/d):	406,149	317,502	88,647
Equity NGLs (Bbls/d):	28,493	27,611	882
Revenues	$ 5,056	$ 6,823	$ (1,767)
Cost of products sold	3,264	4,893	(1,629)
Segment margin	1,792	1,930	(138)
Unrealized (gains) losses on commodity risk management activities	82	(89)	171
Operating expenses, excluding non-cash compensation expense	(616)	(481)	(135)
Selling, general and administrative, excluding non-cash compensation expense	(44)	(54)	10
Adjusted EBITDA related to unconsolidated affiliates	20	12	8
Other	3	—	3
Segment Adjusted EBITDA	$ 1,237	$ 1,318	$ (81)

Volumes. Gathered volumes, NGLs produced and equity NGLs produced increased for the year ended December 31, 2015 compared to the prior year primarily due to the full-year impacts of the acquisitions of the Eagle Rock, PVR and King Ranch midstream assets.

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

	Years Ended December 31, 2015	Years Ended December 31, 2014	Change
Gathering and processing fee-based revenues	$ 1,570	$ 1,278	$ 292
Non fee-based contracts and processing	222	652	(430)
Total segment margin	$ 1,792	$ 1,930	$ (138)

Segment Adjusted EBITDA. For the year ended December 31, 2015 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net impacts of the following:

- a decrease of $88 million in non-fee based margins for natural gas and a $200 million decrease in non-fee based margins for crude oil and NGL due to lower natural gas prices and lower crude oil and NGL prices; and
- an increase of $135 million in operating expenses primarily due to assets recently placed in service, including the Rebel system in West Texas and the King Ranch system in South Texas, as well as the acquisition of Eagle Rock midstream assets in July 2014; partially offset by
- an increase of $136 million in fee-based revenues primarily due to increased production and increased capacity from assets placed in service in the Marcellus Shale, Eagle Ford Shale, Permian Basin and Cotton Valley;
- an increase of $120 million in fee-based margin from the acquisitions of the Eagle Rock, PVR, and King Ranch midstream assets;
- an increase of $80 million in realized derivatives;
- an increase of $8 million of Adjusted EBITDA related to unconsolidated affiliates due to the addition of the Mi Vida JV asset in the Permian Basin; and
- a decrease of $10 million in selling, general and administration expenses due to increased capitalized overhead and higher management fees.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2015	2014	Change
Revenues	$ 5,118	$ 5,125	$ (7)
Cost of products sold	3,458	3,855	(397)
Segment margin	1,660	1,270	390
Unrealized (gains) losses on commodity risk management activities	10	(29)	39
Operating expenses, excluding non-cash compensation expense	(469)	(365)	(104)
Selling, general and administrative expenses, excluding non-cash compensation expense	(55)	(66)	11
Inventory valuation adjustments	12	26	(14)
Adjusted EBITDA related to unconsolidated affiliates	67	55	12
Segment Adjusted EBITDA	$ 1,225	$ 891	$ 334

Segment Adjusted EBITDA. For the year ended December 31, 2015 compared to the prior year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $139 million related to legacy ETP's NGLs operations, as follows:
    - an increase of $69 million in legacy ETP's NGL transportation margin primarily due to higher volumes transported out of West Texas and the Eagle Ford producing regions;
    - an increase of $42 million in processing and fractionation margin (excluding changes in unrealized gains of $8 million) due to $9 million increase in margin from our fractionators due to the ramp-up of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas, and the additional volumes from producers in West Texas and the Eagle Ford regions offset by reductions in blending gains due to lower market prices. Additionally, the commissioning of the Mariner South LPG export project during February 2015 contributed an additional $50 million for the twelve months ended December 31, 2015. Margin associated with our off-gas fractionator in Geismar, Louisiana decreased by $17 million for the year ended December 31, 2015 as NGL and olefin market prices decreased significantly for the comparable period;
    - an increase of $15 million in storage margin due to a $24 million increase in fee based storage margin for year ended December 31, 2015 from an increase in demand for leased storage capacity as a result of favorable market conditions and a specific contract negotiated in connection with the Mariner South LPG export project. The increase in fee based storage margin was offset by lower non-fee based margin of $8 million for the year ended December 31, 2015 primarily due to lower propane blending gains;
    - an increase of $33 million in other margin (excluding changes in unrealized losses of $26 million) primarily due to the withdrawal and sale of physical storage volumes, primarily propane and butanes; and
    - a decrease of $4 million in selling, general and administrative expenses primarily due to lower employee-related costs; partially offset by
    - an increase of $24 million in operating expenses primarily due to a $6 million increase in employee expenses, a $4 million increase in ad valorem taxes, a $3 million increase in utilities expense, a $6 million increase in project costs and materials and supplies expense, and a $5 million increase in overhead expense allocations. The remainder of the increase in operating expenses in the table above is related to Sunoco Logistics' NGLs and refined products operations, the results of which are discussed separately below;
- an increase of $130 million in Adjusted EBITDA from legacy Sunoco Logistics' NGLs operations, primarily due to contributions from Mariner NGLs projects which commenced operations in late 2014 and 2013. These projects contributed to improved results related to legacy Sunoco Logistics' NGLs pipeline and terminal operations of $160 million, including the Nederland and Marcus Hook facilities. These positive impacts were partially offset by lower results from legacy Sunoco Logistics' NGLs acquisition and marketing activities of $33 million driven largely by narrowed blending margins compared to the prior year period; and
- an increase of $65 million in Adjusted EBITDA from legacy Sunoco Logistics' refined products operations, primarily due to higher results from legacy Sunoco Logistics' refined products pipelines of $33 million driven largely by the commencement of operations on the Allegheny Access project in 2015. Terminalling activities at legacy Sunoco Logistics' refined products

marketing terminals, as well as legacy Sunoco Logistics' Eagle Point and Marcus Hook facilities, increased compared to the prior year period by $15 million. Higher contributions from legacy Sunoco Logistics' joint venture interests of $10 million and refined products acquisition and marketing activities of $6 million also contributed to the increase.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2015	2014	Change
Revenue	$ 9,267	$ 17,182	$ (7,915)
Cost of products sold	8,446	16,446	(8,000)
Segment margin	821	736	85
Operating expenses, excluding non-cash compensation expense	(245)	(238)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(53)	(61)	8
Inventory valuation adjustments	150	232	(82)
Adjusted EBITDA related to unconsolidated affiliates	(2)	—	(2)
Other	—	2	(2)
Segment Adjusted EBITDA	$ 671	$ 671	$ —

Segment Adjusted EBITDA. For the year ended December 31, 2015 compared to the prior year, Segment Adjusted EBITDA related to our crude oil transportation and services segment was impacted by the following:

- an increase of $7 million from legacy ETP's commissioning of a crude pipeline in the fourth quarter of 2014; offset by
- a decrease of $13 million from legacy Sunoco Logistics' crude oil operations, primarily due to lower results from our crude oil acquisition and marketing activities of $96 million driven by reduced margins which were negatively impacted by contracted crude oil differentials compared to the prior year period. This impact was partially offset by higher results from our crude oil pipelines of $71 million largely attributable to expansion projects placed into service in 2015 and 2014, and higher results from our crude oil terminals of $14 million.

All Other

	Years Ended December 31,		
	2015	2014	Change
Revenue	$ 15,774	$ 25,818	$ (10,044)
Cost of products sold	14,029	24,129	(10,100)
Segment margin	1,745	1,689	56
Unrealized gains on commodity risk management activities	(1)	(15)	14
Operating expenses, excluding non-cash compensation expense	(896)	(840)	(56)
Selling, general and administrative expenses, excluding non-cash compensation expense	(254)	(251)	(3)
Adjusted EBITDA related to discontinued operations	—	27	(27)
Adjusted EBITDA related to unconsolidated affiliates	313	149	164
Inventory valuation adjustments	(58)	215	(273)
Other	95	93	2
Elimination	(61)	(8)	(53)
Segment Adjusted EBITDA	$ 883	$ 1,059	$ (176)

Amounts reflected in our all other segment primarily include:

- our retail marketing operations prior to the transfer of the general partner interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016;
- our equity method investment in limited partnership units of Sunoco LP consisting of 37.8 million Sunoco LP common units;
- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units;
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities; and
- our investment in AmeriGas until August 2014.

Segment Adjusted EBITDA. For the year ended December 31, 2015 compared to the prior year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $124 million due to the deconsolidation of Sunoco LP as a result of the sale of Sunoco LP's general partner interest and incentive distribution rights to ETE effective July 1, 2015;
- a decrease of $121 million due to unfavorable fuel margins and $9 million due to unfavorable volumes in the retail and wholesale channels;
- a decrease of $49 million in margins as 2014 benefited from favorable regional market conditions for ethanol;
- a decrease of $63 million in Adjusted EBITDA related to unconsolidated affiliates, primarily due to a decrease of $56 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2014; and
- a decrease in Adjusted EBITDA related to discontinued operations of $27 million in the prior period related to a marketing business that was sold effective April 1, 2014; partially offset by
- the favorable impact of $112 million from the acquisition of Susser in August 2014 until its contribution to Sunoco LP in July 2015 and $43 million from other recent acquisitions.
- an increase of $21 million related to our contract services operations primarily due to an increase in revenue-generating horsepower; and
- an increase of $17 million related to our natural resources operations, for which the period reflected only a partial period due to the acquisition of those operations in March 2014.

ETP provides management services for ETE for which ETE has agreed to pay management fees to ETP of $95 million per year for the years ending December 31, 2015 and 2014. These fees were reflected in "Other" in the "All other" segment and for the years ended December 31, 2015 and 2014 were reflected as an offset to operating expenses of $32 million and selling, general and administrative expenses of $63 million in the consolidated statements of operations.

Liquidity and Capital Resources

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Cash Flows

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Description of Indebtedness

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Contractual Obligations

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Cash Distributions

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

New Accounting Standards

See information previously included in our Form 10-K filed on February 24, 2017 and Form 8-K filed on May 8, 2017.

Estimates and Critical Accounting Policies

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

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2016 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.

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

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

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

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

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

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

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

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

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

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

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.

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

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

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

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

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

Fair Value of Financial Instruments. We have commodity derivatives, interest rate derivatives and embedded derivatives in our 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 embedded derivatives in our 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. 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.

The Partnership determined the fair value of its reporting units using a weighted combination of the discounted cash flow method and the guideline company method. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The Partnership believes the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the Partnership determined fair value based on estimated future cash flows of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflect the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur. Under the guideline company method, the Partnership determined the estimated fair value of each of our reporting units by applying valuation multiples of comparable publicly-traded companies to each reporting unit's projected EBITDA and then averaging that estimate with similar historical calculations using a three year average. In addition, the Partnership estimated a reasonable control premium representing the incremental value that accrues to the majority owner from the opportunity to dictate the strategic and operational actions of the business.

One key assumption for the measurement of goodwill impairment is management's estimate of future cash flows and EBITDA. These estimates are based on the annual budget for the upcoming year and forecasted amounts for multiple subsequent years. The annual budget process is typically completed near the annual goodwill impairment testing date, and management uses the most recent information for the annual impairment tests. The forecast is also subjected to a comprehensive update annually in conjunction with the annual budget process and is revised periodically to reflect new information and/or revised expectations. The estimates of future cash flows and EBITDA are subjective in nature and are subject to impacts from the business risks described in "Item 1A. Risk Factors." Therefore, the actual results could differ significantly from the amounts used for goodwill impairment testing, and significant changes in fair value estimates could occur in a given period.

The goodwill impairments recorded by the Partnership during the years ended December 31, 2016 and 2015 represented all of the goodwill within the respective reporting units.

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the consolidated statement of operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful lives ranging from 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 and Sunoco Logistics discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2016 and 2015, 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.

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.

Long-lived assets related to AROs aggregated $14 million and $18 million, and were reflected as property, plant and equipment on our balance sheet as of December 31, 2016 and 2015, respectively. In addition, the Partnership had $13 million and $6 million legally restricted funds for the purpose of settling AROs that was reflected as other non-current assets as of December 31, 2016 and 2015, respectively.

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

The calculation of the net periodic benefit cost and benefit obligation requires the use of a number of assumptions. Changes in these assumptions can have a significant effect on the amounts reported in the financial statements. The Partnership believes that the two most critical assumptions are the assumed discount rate and the expected rate of return on plan assets.

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

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

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

For more information on our litigation and contingencies, see Note 11 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary 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. 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.

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. The Partnership'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, 2016, the aggregate of the estimated maximum reasonably possible losses, which relate to numerous individual sites, totaled approximately $5 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. ETP recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards ("NOLs") and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce deferred tax assets to an amount that is more likely than not to be realized by the Partnership in the future. Deferred income tax assets attributable to state and federal NOLs and federal tax alternative minimum tax credit carryforwards totaling $380 million have been included in ETP's consolidated balance sheet as of December 31, 2016. All of the deferred income tax assets attributable to state and federal NOL benefits expire before 2036 as more fully described below. The state NOL carryforward benefits of $124 million (net of federal benefit) begin to expire in 2017 with a substantial portion expiring between 2029 and 2036. The federal NOLs of $580 million ($203 million in benefits) will expire in 2032 and 2035. Federal alternative minimum tax credit carryforwards of $52 million remained at December 31, 2016. We have determined that a valuation allowance totaling $118 million (net of federal income tax effects) is required for the state NOLs at December 31, 2016 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 based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;

- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

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

Inflation

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (as discussed in Note 1, Energy Transfer Partners, L.P. and Sunoco Logistics Partners L.P. completed a merger on April 28, 2017) (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2016 and 2015, 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, 2016. 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 financial position of Energy Transfer Partners, L.P. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 24, 2017 (except for all unit and per unit amounts as discussed in Note 1 and for Notes 15 and 17, which are as of August 14, 2017)

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

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 360	$ 527
Accounts receivable, net	3,002	2,118
Accounts receivable from related companies	209	268
Inventories	1,712	1,213
Derivative assets	20	40
Other current assets	426	532
Total current assets	5,729	4,698
Property, plant and equipment	58,220	50,869
Accumulated depreciation and depletion	(7,303)	(5,782)
	50,917	45,087
Advances to and investments in unconsolidated affiliates	4,280	5,003
Other non-current assets, net	672	536
Intangible assets, net	4,696	4,421
Goodwill	3,897	5,428
Total assets	$ 70,191	$ 65,173

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

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

	December 31, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 2,900	$ 1,859
Accounts payable to related companies	43	25
Derivative liabilities	166	63
Accrued and other current liabilities	1,905	2,048
Current maturities of long-term debt	1,189	126
Total current liabilities	6,203	4,121
Long-term debt, less current maturities	31,741	28,553
Long-term notes payable – related company	250	233
Non-current derivative liabilities	76	137
Deferred income taxes	4,394	4,082
Other non-current liabilities	952	968
Commitments and contingencies		
Series A Preferred Units	33	33
Redeemable noncontrolling interests	15	15
Equity:		
General Partner	206	306
Limited Partners:		
Common Unitholders (794,803,853 and 758,468,555 units authorized, issued and outstanding as of December 31, 2016 and 2015, respectively)	14,946	17,043
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary)	—	—
Class G Unitholders (90,706,000 units authorized, issued and outstanding – held by subsidiary)	—	—
Class H Unitholders (81,001,069 units authorized, issued and outstanding as of December 31, 2016 and 2015)	3,480	3,469
Class I Unitholders (100 units authorized, issued and outstanding)	2	14
Class K Unitholders (101,525,429 and 0 units authorized, issued and outstanding as of December 31, 2016 and 2015, respectively – held by subsidiary)	—	—
Accumulated other comprehensive income	8	4
Total partners’ capital	18,642	20,836
Noncontrolling interest	7,885	6,195
Total equity	26,527	27,031
Total liabilities and equity	$ 70,191	$ 65,173

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

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

	Years Ended December 31,		
	2016	2015	2014
REVENUES:			
Natural gas sales	$ 3,619	$ 3,671	$ 5,386
NGL sales	4,841	3,936	5,845
Crude sales	6,766	8,378	16,416
Gathering, transportation and other fees	4,003	3,997	3,517
Refined product sales (see Note 3)	1,047	9,958	19,437
Other (see Note 3)	1,551	4,352	4,874
Total revenues	21,827	34,292	55,475
COSTS AND EXPENSES:			
Cost of products sold (see Note 3)	15,394	27,029	48,414
Operating expenses (see Note 3)	1,484	2,261	2,059
Depreciation, depletion and amortization	1,986	1,929	1,669
Selling, general and administrative (see Note 3)	348	475	520
Impairment losses	813	339	370
Total costs and expenses	20,025	32,033	53,032
OPERATING INCOME	1,802	2,259	2,443
OTHER INCOME (EXPENSE):			
Interest expense, net	(1,317)	(1,291)	(1,165)
Equity in earnings from unconsolidated affiliates	59	469	332
Impairment of investment in an unconsolidated affiliate	(308)	—	—
Gains on acquisitions	83	—	—
Gain on sale of AmeriGas common units	—	—	177
Losses on extinguishments of debt	—	(43)	(25)
Losses on interest rate derivatives	(12)	(18)	(157)
Other, net	131	22	(12)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	438	1,398	1,593
Income tax expense (benefit) from continuing operations	(186)	(123)	358
INCOME FROM CONTINUING OPERATIONS	624	1,521	1,235
Income from discontinued operations	—	—	64
NET INCOME	624	1,521	1,299
Less: Net income attributable to noncontrolling interest	327	157	116
Less: Net loss attributable to predecessor	—	(34)	(153)
NET INCOME ATTRIBUTABLE TO PARTNERS	297	1,398	1,336
General Partner’s interest in net income	948	1,064	513
Class H Unitholder’s interest in net income	351	258	217
Class I Unitholder’s interest in net income	8	94	—
Common Unitholders’ interest in net income (loss)	$ (1,010)	$ (18)	$ 606
INCOME (LOSS) FROM CONTINUING OPERATIONS PER COMMON UNIT:			
Basic	$ (1.37)	$ (0.06)	$ 1.05
Diluted	$ (1.37)	$ (0.07)	$ 1.05
NET INCOME (LOSS) PER COMMON UNIT:			
Basic	$ (1.37)	$ (0.06)	$ 1.18
Diluted	$ (1.37)	$ (0.07)	$ 1.18

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2016	2015	2014
Net income	$ 624	$ 1,521	$ 1,299
Other comprehensive income (loss), net of tax:			
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	—	—	3
Change in value of available-for-sale securities	2	(3)	1
Actuarial gain (loss) relating to pension and other postretirement benefits	(1)	65	(113)
Foreign currency translation adjustment	(1)	(1)	(2)
Change in other comprehensive income from unconsolidated affiliates	4	(1)	(6)
	4	60	(117)
Comprehensive income	628	1,581	1,182
Less: Comprehensive income attributable to noncontrolling interest	327	157	116
Less: Comprehensive loss attributable to predecessor	—	(34)	(153)
Comprehensive income attributable to partners	$ 301	$ 1,458	$ 1,219

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

		Limited Partners						
	General Partner	Common Unitholders	Class H Units	Class I Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Predecessor Equity	Total
Balance, December 31, 2013	$ 171	$ 9,797	$ 1,511	$ —	$ 61	$ 3,780	$ 3,374	$ 18,694
Distributions to partners	(500)	(1,252)	(212)	—	—	—	—	(1,964)
Distributions to noncontrolling interest	—	—	—	—	—	(241)	—	(241)
Units issued for cash	—	1,382	—	—	—	—	—	1,382
Subsidiary units issued for cash	1	174	—	—	—	1,069	—	1,244
Capital contributions from noncontrolling interest	—	—	—	—	—	67	—	67
Lake Charles LNG Transaction	—	(1,167)	—	—	—	—	—	(1,167)
Susser Merger	—	908	—	—	—	626	—	1,534
Sunoco Logistics acquisition of a noncontrolling interest	(1)	(79)	—	—	—	(245)	—	(325)
Predecessor distributions to partners	—	—	—	—	—	—	(645)	(645)
Predecessor units issued for cash	—	—	—	—	—	—	1,227	1,227
Predecessor equity issued for acquisitions, net of cash received	—	—	—	—	—	—	4,281	4,281
Other comprehensive loss, net of tax	—	—	—	—	(117)	—	—	(117)
Other, net	—	61	(4)	—	—	(19)	4	42
Net income (loss)	513	606	217	—	—	116	(153)	1,299
Balance, December 31, 2014	184	10,430	1,512	—	(56)	5,153	8,088	25,311
Distributions to partners	(944)	(1,863)	(247)	(80)	—	—	—	(3,134)
Distributions to noncontrolling interest	—	—	—	—	—	(338)	—	(338)
Units issued for cash	—	1,428	—	—	—	—	—	1,428
Subsidiary units issued for cash	2	298	—	—	—	1,219	—	1,519
Capital contributions from noncontrolling interest	—	—	—	—	—	875	—	875
Bakken Pipeline Transaction	—	(999)	1,946	—	—	72	—	1,019
Sunoco LP Exchange Transaction	—	(52)	—	—	—	(940)	—	(992)
Susser Exchange Transaction	—	(68)	—	—	—	—	—	(68)
Acquisition and disposition of noncontrolling interest	—	(26)	—	—	—	(39)	—	(65)
Predecessor distributions to partners	—	—	—	—	—	—	(202)	(202)
Predecessor units issued for cash	—	—	—	—	—	—	34	34
Regency Merger	—	7,890	—	—	—	—	(7,890)	—
Other comprehensive income, net of tax	—	—	—	—	60	—	—	60
Other, net	—	23	—	—	—	36	4	63

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

Net income (loss)	1,064	(18)	258	94	—	157	(34)	1,521
Balance, December 31, 2015	$ 306	$ 17,043	$ 3,469	$ 14	$ 4	$ 6,195	$ —	$ 27,031
Distributions to partners	(1,048)	(2,134)	(340)	(20)	—	—	—	(3,542)
Distributions to noncontrolling interest	—	—	—	—	—	(481)	—	(481)
Units issued for cash	—	1,098	—	—	—	—	—	1,098
Subsidiary units issued	—	37	—	—	—	1,351	—	1,388
Capital contributions from noncontrolling interest	—	—	—	—	—	236	—	236
Sunoco, Inc. retail business to Sunoco LP transaction	—	(405)	—	—	—	—	—	(405)
PennTex Acquisition	—	307	—	—	—	236	—	543
Other comprehensive income, net of tax	—	—	—	—	4	—	—	4
Other, net	—	10	—	—	—	21	—	31
Net income (loss)	948	(1,010)	351	8	—	327	—	624
Balance, December 31, 2016	$ 206	$ 14,946	$ 3,480	$ 2	$ 8	$ 7,885	$ —	$ 26,527

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31, 2016	2015	2014
OPERATING ACTIVITIES:			
Net income	$ 624	$ 1,521	$ 1,299
Reconciliation of net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,986	1,929	1,669
Deferred income taxes	(169)	202	(49)
Amortization included in interest expense	(20)	(36)	(60)
Inventory valuation adjustments	(170)	104	473
Unit-based compensation expense	80	79	68
Impairment losses	813	339	370
Gains on acquisitions	(83)	—	—
Gain on sale of AmeriGas common units	—	—	(177)
Losses on extinguishments of debt	—	43	25
Impairment of investment in an unconsolidated affiliate	308	—	—
Distributions on unvested awards	(25)	(16)	(16)
Equity in earnings of unconsolidated affiliates	(59)	(469)	(332)
Distributions from unconsolidated affiliates	406	440	291
Other non-cash	(271)	(22)	(72)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	(117)	(1,367)	(320)
Net cash provided by operating activities	3,303	2,747	3,169
INVESTING ACTIVITIES:			
Proceeds from the Sunoco, Inc. retail business to Sunoco LP transaction	2,200	—	—
Proceeds from Bakken Pipeline Transaction	—	980	—
Proceeds from Susser Exchange Transaction	—	967	—
Proceeds from sale of noncontrolling interest	—	64	—
Proceeds from the sale of AmeriGas common units	—	—	814
Cash paid for Vitol Acquisition, net of cash received	(769)	—	—
Cash paid for PennTex Acquisition, net of cash received	(299)	—	—
Cash transferred to ETE in connection with the Sunoco LP Exchange	—	(114)	—
Cash paid for acquisition of a noncontrolling interest	—	(129)	(325)
Cash paid for Susser Merger, net of cash received	—	—	(808)
Cash paid for predecessor acquisitions, net of cash received	—	—	(762)
Cash paid for all other acquisitions	(159)	(675)	(472)
Capital expenditures, excluding allowance for equity funds used during construction	(7,550)	(9,098)	(5,213)
Contributions in aid of construction costs	71	80	45
Contributions to unconsolidated affiliates	(59)	(45)	(399)
Distributions from unconsolidated affiliates in excess of cumulative earnings	135	124	136
Proceeds from sale of discontinued operations	—	—	77
Proceeds from the sale of assets	25	23	61
Change in restricted cash	14	19	172
Other	1	(16)	(18)
Net cash used in investing activities	(6,390)	(7,820)	(6,692)

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

FINANCING ACTIVITIES:			
Proceeds from borrowings	19,916	22,462	15,354
Repayments of long-term debt	(15,799)	(17,843)	(12,702)
Proceeds from affiliate notes	4,997	233	—
Repayments on affiliate notes	(4,873)	—	—
Units issued for cash	1,098	1,428	1,382
Subsidiary units issued for cash	1,388	1,519	1,244
Predecessor units issued for cash	—	34	1,227
Capital contributions from noncontrolling interest	236	841	67
Distributions to partners	(3,542)	(3,134)	(1,964)
Predecessor distributions to partners	—	(202)	(645)
Distributions to noncontrolling interest	(481)	(338)	(241)
Debt issuance costs	(22)	(63)	(63)
Other	2	—	(41)
Net cash provided by financing activities	2,920	4,937	3,618
Increase (decrease) in cash and cash equivalents	(167)	(136)	95
Cash and cash equivalents, beginning of period	527	663	568
Cash and cash equivalents, end of period	$ 360	$ 527	$ 663

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar and unit amounts, except per unit data, are in millions)

1. OPERATIONS AND BASIS OF PRESENTATION:

Organization. The consolidated financial statements presented herein contain the results of Energy Transfer Partners, L.P. and its subsidiaries (the "Partnership," "we," "us," "our" or "ETP"). The Partnership is managed by our general partner, ETP GP, which is in turn managed by its general partner, ETP LLC. ETE, a publicly traded master limited partnership, owns ETP LLC, the general partner of our General Partner.

In April 2017, ETP and Sunoco Logistics completed the previously announced merger transaction in which Sunoco Logistics acquired ETP in a unit-for-unit transaction (the "Sunoco Logistics Merger"). Under the terms of the transaction, ETP unitholders received 1.5 common units of Sunoco Logistics for each common unit of ETP they owned. Under the terms of the merger agreement, Sunoco Logistics' general partner was merged with and into ETP GP, with ETP GP surviving as an indirect wholly-owned subsidiary of ETE. In connection with the merger, the ETP Class H units were cancelled. The outstanding ETP Class E units, Class G units, Class I units and Class K units at the effective time of the merger were converted into an equal number of newly created classes of Sunoco Logistics units, with the same rights, preferences, privileges, duties and obligations as such classes of ETP units had immediately prior to the closing of the merger. Additionally, the outstanding Sunoco Logistics common units and Sunoco Logistics Class B units owned by ETP at the effective time of the merger were cancelled.

In connection with the Sunoco Logistics Merger, ETP changed its name from "Energy Transfer Partners, L.P." to "Energy Transfer, LP" and Sunoco Logistics Partners L.P. changed its name to "Energy Transfer Partners, L.P." For purposes of maintaining clarity, the following references are used herein:

- References to "ETP" refer to the entity named Energy Transfer Partners, L.P. prior to the close of the merger and Energy Transfer, LP subsequent to the close of the merger;
- References to "Sunoco Logistics" refer to the entity named Sunoco Logistics Partners L.P. prior to the close of the merger; and
- References to "Post-Merger ETP" refer to the consolidated entity named Energy Transfer Partners, L.P. subsequent to the close of the merger.

The Sunoco Logistics Merger resulted in Energy Transfer Partners, L.P. being treated as the surviving consolidated entity from an accounting perspective, while Sunoco Logistics (prior to changing its name to "Energy Transfer Partners, L.P.") was the surviving consolidated entity from a legal and reporting perspective. Therefore, for the pre-merger periods, the consolidated financial statements reflect the consolidated financial statements of the legal acquiree (i.e., the entity that was named "Energy Transfer Partners, L.P." prior to the merger and name changes).

The Sunoco Logistics Merger was accounted for as an equity transaction. The Sunoco Logistics Merger did not result in any changes to the carrying values of assets and liabilities in the consolidated financial statements, and no gain or loss was recognized. For the periods prior to the Sunoco Logistics Merger, the Sunoco Logistics limited partner interests that were owned by third parties (other than Energy Transfer Partners, L.P. or its consolidated subsidiaries) are presented as noncontrolling interest in these consolidated financial statements.

The historical common units and net income (loss) per limited partner unit amounts presented in these consolidated financial statements have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

The Partnership is engaged in the gathering and processing, compression, treating and transportation of natural gas, focusing 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 and Avalon shales.

The Partnership is engaged in intrastate transportation and storage natural gas operations that own and operate natural gas pipeline systems that are 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.

The Partnership owns and operates interstate pipelines, either directly or through equity method investments, that transport natural gas to various markets in the United States.

The Partnership owns a controlling interest in Sunoco Logistics, a publicly traded Delaware limited partnership that owns and operates a logistics business, consisting of crude oil, NGL and refined products pipelines.

The Partnership owns a controlling interest in PennTex, a publicly traded Delaware limited partnership that provides natural gas gathering and processing and residue gas and natural gas liquids transportation services to producers.

Basis of Presentation. The consolidated financial statements of the Partnership have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year amounts have been conformed to the current year presentation. These reclassifications had no impact on net income or total equity. Management evaluated subsequent events through the date the financial statements were issued.

The Partnership owns 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, these undivided interests are consolidated proportionately.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream, NGL and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the estimated operating results represent the actual results in all material respects.

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

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.

In August 2015, the FASB deferred the effective date of ASU 2014-09, which is now effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The guidance permits two methods of adoption: retrospectively to each prior reporting period presented (full retrospective method), or retrospectively with the cumulative effect of initially applying the guidance recognized at the date of initial application (the cumulative catchup transition method). The Partnership expects to adopt ASU 2014-09 in the first quarter of 2018 and will apply the cumulative catchup transition method.

We are in the process of evaluating our revenue contracts by segment and fee type to determine the potential impact of adopting the new standards. At this point in our evaluation process, we have determined that the timing and/or amount of revenue that we recognize on certain contracts may be impacted by the adoption of the new standard; however, we are still in the process of quantifying these impacts and cannot say whether or not they would be material to our financial statements. In addition, we are in the process of implementing appropriate changes to our business processes, systems and controls to support recognition and disclosure under the new standard. We continue to monitor additional authoritative or interpretive guidance related to the new standard as it becomes available, as well as comparing our conclusions on specific interpretative issues to other peers in our industry, to the extent that such information is available to us.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, *Leases (Topic 842)* (“ASU 2016-02”), which establishes the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. The Partnership is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

On January 1, 2017, the Partnership adopted Accounting Standards Update No. 2016-09, *Stock Compensation (Topic 718)* (“ASU 2016-09”). The objective of the update is to reduce complexity in accounting standards. The areas for simplification in this update involve several aspects of the accounting for employee share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of this standard did not have a material impact on the Partnership’s consolidated financial statements and related disclosures.

In October 2016, the FASB issued Accounting Standards Update No. 2016-16, *Income Taxes (Topic 740): Intra-entity Transfers of Assets Other Than Inventory* (“ASU 2016-16”), which requires that entities recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The amendments in this update do not change GAAP for the pre-tax effects of an intra-entity asset transfer under Topic 810, Consolidation, or for an intra-entity transfer of inventory. ASU 2016-16 is effective for fiscal years beginning after December 15, 2017, and interim periods within those annual periods. Early adoption is permitted. The Partnership is currently evaluating the impact that adoption of this standard will have on the consolidated financial statements and related disclosures.

On January 1, 2017, the Partnership adopted Accounting Standards Update No. 2016-17, *Consolidation (Topic 810): Interests Held Through Related Parties That Are Under Common Control* (“ASU 2016-17”), which amends the consolidation guidance on how a reporting entity that is the single decision maker of a variable interest entity (VIE) should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. Under the amendments, a single decision maker is required to include indirect interests on a proportionate basis consistent with indirect interests held through other related parties. The adoption of this standard did not have an impact on the Partnership’s consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-04 “*Intangibles-Goodwill and other (Topic 350): Simplifying the test for goodwill impairment.*” The amendments in this update remove the second step of the two-step test currently required by Topic 350. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This ASU is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted. We expect that our adoption of this standard will change our approach for testing goodwill for impairment; however, this standard requires prospective application and therefore will only impact periods subsequent to adoption.

Revenue Recognition

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

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

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

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

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

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

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

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

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

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

Regulatory Accounting – Regulatory Assets and Liabilities

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

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply regulatory accounting policies in accounting for its operations. Panhandle does not apply regulatory accounting policies primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

The net change in operating assets and liabilities (net of effects of acquisitions and deconsolidations) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31,		
	2016	2015	2014
Accounts receivable	$ (919)	$ 819	$ 600
Accounts receivable from related companies	30	(243)	(22)
Inventories	(368)	(351)	51
Other current assets	83	(178)	150
Other non-current assets, net	(78)	188	(6)
Accounts payable	972	(1,215)	(851)
Accounts payable to related companies	29	(160)	3
Accrued and other current liabilities	39	(83)	(191)
Other non-current liabilities	33	(219)	(73)
Price risk management assets and liabilities, net	62	75	19
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$ (117)	$ (1,367)	$ (320)

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

	Years Ended December 31,		
	2016	2015	2014
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 822	$ 896	$ 643
Sunoco LP limited partner interest received in exchange for contribution of the Sunoco, Inc. retail business to Sunoco LP	194	—	—
Net gains from subsidiary common unit transactions	37	300	175
NON-CASH FINANCING ACTIVITIES:			
Issuance of Common Units in connection with the PennTex Acquisition	$ 307	$ —	$ —
Issuance of Common Units in connection with the Regency Merger	—	9,250	—
Issuance of Class H Units in connection with the Bakken Pipeline Transaction	—	1,946	—
Issuance of Common Units in connection with the Susser Merger	—	—	908
Contribution of property, plant and equipment from noncontrolling interest	—	34	—
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	—	—	564
Predecessor equity issuances of common units in connection with Regency's acquisitions	—	—	4,281
Long-term debt assumed or exchanged in Regency's acquisitions	—	—	2,386
Redemption of Common Units in connection with the Bakken Pipeline Transaction	—	999	—
Redemption of Common Units in connection with the Sunoco LP Exchange	—	52	—
Redemption of Common Units in connection with the Lake Charles LNG Transaction	—	—	1,167
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,411	$ 1,467	$ 1,232
Cash paid for (refund of) income taxes	(229)	71	344

Accounts Receivable

Our midstream, NGL and intrastate transportation and storage operations deal with a variety of counterparties across the energy sector, some of which are investment grade, and most of which are not. Internal credit ratings and credit limits are assigned to all counterparties and limits are monitored against credit exposure. Letters of credit or prepayments may be required from those counterparties that are not investment grade depending on the internal credit rating and level of commercial activity with the counterparty. Master setoff agreements are put in place with counterparties where appropriate to mitigate risk. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible.

We have a diverse portfolio of customers, however, because of the midstream and transportation services we provide, many of our customers are engaged in the exploration and production segment. We manage trade credit risk to mitigate credit losses and exposure to uncollectible trade receivables. Prospective and existing customers are reviewed regularly for creditworthiness to manage credit risk within approved tolerances. Customers that do not meet minimum credit standards are required to provide additional credit support in the form of a letter of credit, prepayment, or other forms of security. We establish an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and considers many factors including historical customer collection experience, general and specific economic trends, and known specific issues related to individual customers, sectors, and transactions that might impact collectability. Increases in the allowance are recorded as a component of operating expenses; reductions in the allowance are recorded when receivables are subsequently collected or written-off. Past due receivable balances are written-off when our efforts have been unsuccessful in collecting the amount due.

We enter into netting arrangements with counterparties to the extent possible to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

Inventories

Inventories consist principally of natural gas held in storage, crude oil, refined products and spare parts. 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 refined products is determined using the last-in, first out method. The cost of spare parts is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31,	
	2016	2015
Natural gas and NGLs	$ 699	$ 415
Crude oil	683	424
Refined products	113	104
Spare parts and other	217	270
Total inventories	$ 1,712	$ 1,213

During the years ended December 31, 2016 and 2015, the Partnership recorded write-downs of $170 million and $104 million, respectively, on its crude oil, refined products and NGL inventories as a result of declines in the market price of these products. The write-downs were calculated based upon current replacement costs.

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. Changes in fair value of designated hedged inventory are recorded in inventory on our consolidated balance sheets and cost of products sold in our consolidated statements of operations.

Other Current Assets

Other current assets consisted of the following:

	December 31,	
	2016	2015
Deposits paid to vendors	$ 74	$ 74
Income taxes receivable	128	291
Prepaid expenses and other	224	167
Total other current assets	$ 426	$ 532

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC mandated lives of the assets, if applicable. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our consolidated statements of operations.

Property, plant and equipment is reviewed 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.

In 2016, the Partnership recorded a $133 million fixed asset impairment related to the interstate transportation and storage segment primarily due to expected decreases in future cash flows driven by declines in commodity prices as well as a $10 million impairment to property, plant and equipment in the midstream segment. In 2015, the Partnership recorded a $110 million fixed asset impairment related to the NGL and refined products transportation and services segment primarily due to an expected decrease in future cash flows. No other fixed asset impairments were identified or recorded for our reporting units during the periods presented.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31,	
	2016	2015
Land and improvements	$ 659	$ 686
Buildings and improvements (1 to 45 years)	1,784	1,526
Pipelines and equipment (5 to 83 years)	35,923	33,148
Natural gas and NGL storage facilities (5 to 46 years)	1,515	391
Bulk storage, equipment and facilities (2 to 83 years)	3,677	2,853
Retail equipment (2 to 99 years)	—	401
Vehicles (1 to 25 years)	241	220
Right of way (20 to 83 years)	3,374	2,573
Natural resources	434	484
Other (1 to 40 years)	517	743
Construction work-in-process	10,096	7,844
	58,220	50,869
Less – Accumulated depreciation and depletion	(7,303)	(5,782)
Property, plant and equipment, net	$ 50,917	$ 45,087

We recognized the following amounts for the periods presented:

	Years Ended December 31,		
	2016	2015	2014
Depreciation and depletion expense	$ 1,793	$ 1,713	$ 1,457
Capitalized interest, excluding AFUDC	200	163	101

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies.

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,	
	2016	2015
Unamortized financing costs[1]	$ 3	$ 11
Regulatory assets	86	90
Deferred charges	217	198
Restricted funds	190	192
Long-term affiliated receivable	90	—
Other	86	45
Total other non-current assets, net	$ 672	$ 536

(1) Includes unamortized financing costs related to the Partnership's revolving credit facilities.

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

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. The Partnership removes 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, 2016		December 31, 2015	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 5,362	$ (737)	$ 4,601	$ (554)
Patents (10 years)	48	(21)	48	(16)
Trade Names (20 years)	66	(22)	66	(18)
Other (1 to 15 years)	2	(2)	6	(3)
Total amortizable intangible assets	$ 5,478	$ (782)	$ 4,721	$ (591)
Non-amortizable intangible assets:				
Trademarks	—	—	291	—
Total intangible assets	$ 5,478	$ (782)	$ 5,012	$ (591)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2016	2015	2014
Reported in depreciation, depletion and amortization	$ 193	$ 216	$ 212

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:		
2017	$	213
2018		213
2019		211
2020		211
2021		211

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.

In 2015, we recorded $24 million of intangible asset impairments related to the NGL and refined products transportation and services segment primarily due to an expected decrease in future cash flows.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. The annual impairment test is performed during the fourth quarter.

Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation and Storage	Midstream	NGL and Refined Products Transportation and Services	Crude Oil Transportation and Services	All Other	Total
Balance, December 31, 2014	$ 10	$ 1,011	$ 767	$ 878	$ 912	$ 4,064	$ 7,642
Reduction due to Sunoco LP deconsolidation	—	—	—	—	—	(2,018)	(2,018)
Impaired	—	(99)	—	(106)	—	—	(205)
Other	—	—	(49)	—	—	58	9
Balance, December 31, 2015	10	912	718	772	912	2,104	5,428
Acquired	—	—	177	—	251	—	428
Reduction due to contribution of legacy Sunoco, Inc. retail business	—	—	—	—	—	(1,289)	(1,289)
Impaired	—	(638)	(32)	—	—	—	(670)
Balance, December 31, 2016	$ 10	$ 274	$ 863	$ 772	$ 1,163	$ 815	$ 3,897

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.

During the fourth quarter of 2016, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments of $638 million the interstate transportation and storage segment and $32 million in the midstream segment primarily due to decreases in projected future revenues and cash flows driven by declines in commodity prices and changes in the markets that these assets serve.

During the fourth quarter of 2015, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments of: (i) $99 million in the Transwestern reporting unit due primarily to the market declines in current and expected future commodity prices in the fourth quarter of 2015 and (ii) $106 million in the Lone Star Refinery Services reporting unit due primarily to changes in assumptions related to potential future revenues decrease as well as the market declines in current and expected future commodity prices.

The Partnership determined the fair value of our reporting units using a weighted combination of the discounted cash flow method and the guideline company method. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The Partnership believes the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the Partnership determined fair value based on estimated future cash flows of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflect the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur. Under the guideline company method, the Partnership determined the estimated fair value of each of our reporting units by applying valuation multiples of comparable publicly-traded companies to each reporting unit's projected EBITDA and then averaging that estimate with similar historical calculations using a three year average. In addition, the Partnership estimated a reasonable control premium representing the incremental value that accrues to the majority owner from the opportunity to dictate the strategic and operational actions of the business.

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 and Sunoco Logistics discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2016 and 2015, 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.

As of December 31, 2017 and 2016, other non-current liabilities in ETP's consolidated balance sheets included AROs of $170 million and $212 million, respectively.

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.

Long-lived assets related to AROs aggregated $14 million and $18 million, and were reflected as property, plant and equipment on our balance sheet as of December 31, 2016 and 2015, respectively. In addition, the Partnership had $13 million and $6 million legally restricted funds for the purpose of settling AROs that was reflected as other non-current assets as of December 31, 2016 and 2015, respectively.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2016	2015
Interest payable	$ 440	$ 425
Customer advances and deposits	56	95
Accrued capital expenditures	749	743
Accrued wages and benefits	212	218
Taxes payable other than income taxes	63	76
Exchanges payable	208	105
Other	177	386
Total accrued and other current liabilities	$ 1,905	$ 2,048

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

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 ETP's consolidated balance sheet.

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.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2016 was $33.85 billion and $32.93 billion, respectively. As of December 31, 2015, the aggregate fair value and carrying amount of our debt obligations was $25.71 billion and $28.68 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 and embedded derivatives in our 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 embedded derivatives in our 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. During the year ended December 31, 2016, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2016 and 2015 based on inputs used to derive their fair values:

		Fair Value Measurements at December 31, 2016		
	Fair Value Total	Level 1	Level 2	Level 3
Assets:				
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	$ 14	$ 14	$ —	$ —
Swing Swaps IFERC	2	—	2	—
Fixed Swaps/Futures	96	96	—	—
Forward Physical Swaps	1	—	1	—
Power:				
Forwards	4	—	4	—
Futures	1	1	—	—
Options – Calls	1	1	—	—
Natural Gas Liquids – Forwards/Swaps	233	233	—	—
Refined Products – Futures	1	1	—	—
Crude – Futures	9	9	—	—
Total commodity derivatives	362	355	7	—
Total assets	$ 362	$ 355	$ 7	$ —
Liabilities:				
Interest rate derivatives	$ (193)	$ —	$ (193)	$ —
Embedded derivatives in the ETP Preferred Units	(1)	—	—	(1)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(11)	(11)	—	—
Swing Swaps IFERC	(3)	—	(3)	—
Fixed Swaps/Futures	(149)	(149)	—	—
Power:				
Forwards	(5)	—	(5)	—
Futures	(1)	(1)	—	—
Natural Gas Liquids – Forwards/Swaps	(273)	(273)	—	—
Refined Products – Futures	(17)	(17)	—	—
Crude – Futures	(13)	(13)	—	—
Total commodity derivatives	(472)	(464)	(8)	—
Total liabilities	$ (666)	$ (464)	$ (201)	$ (1)

	Fair Value Total	Fair Value Measurements at December 31, 2015 Level 1	Level 2	Level 3
Assets:				
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	$ 16	$ 16	$ —	$ —
Swing Swaps IFERC	10	2	8	—
Fixed Swaps/Futures	274	274	—	—
Forward Physical Swaps	4	—	4	—
Power:				
Forwards	22	—	22	—
Futures	3	3	—	—
Options – Puts	1	1	—	—
Options – Calls	1	1	—	—
Natural Gas Liquids – Forwards/Swaps	99	99	—	—
Refined Products – Futures	9	9	—	—
Crude – Futures	9	9	—	—
Total commodity derivatives	448	414	34	—
Total assets	$ 448	$ 414	$ 34	$ —
Liabilities:				
Interest rate derivatives	$ (171)	$ —	$ (171)	$ —
Embedded derivatives in the ETP Preferred Units	(5)	—	—	(5)
Commodity derivatives:				
Natural Gas:				
Basis Swaps IFERC/NYMEX	(16)	(16)	—	—
Swing Swaps IFERC	(12)	(2)	(10)	—
Fixed Swaps/Futures	(203)	(203)	—	—
Power:				
Forwards	(22)	—	(22)	—
Futures	(2)	(2)	—	—
Options – Puts	(1)	(1)	—	—
Natural Gas Liquids – Forwards/Swaps	(89)	(89)	—	—
Crude – Futures	(5)	(5)	—	—
Total commodity derivatives	(350)	(318)	(32)	—
Total liabilities	$ (526)	$ (318)	$ (203)	$ (5)

The following table presents the material unobservable inputs used to estimate the fair value of ETP's Preferred Units and the embedded derivatives in ETP's Preferred Units:

	Unobservable Input	December 31, 2016
Embedded derivatives in the ETP Preferred Units	Credit Spread	5.12%
	Volatility	31.73%

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 ETP'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 ETP Preferred Units. Changes in ETP'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, 2016.

Balance, December 31, 2015	$	(5)
Net unrealized gains included in other income (expense)		4
Balance, December 31, 2016	$	(1)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

Shipping and handling costs 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 our hedging and other commodity derivative activities, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis except for our all other segment in which consumer excise taxes on sales of refined products and merchandise are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income (loss). For the year ended December 31, 2016, due to the dropdown of our retail assets to Sunoco LP, no excise taxes were collected. For the years ended December 31, 2015 and 2014, excise taxes collected by our all other segment were $1.85 billion and $2.46 billion, 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 subsidiary's issuance of common units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the noncontrolling interest is adjusted as a change in partners' capital.

Income Taxes

ETP is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under our Second Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, ETP would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2016, 2015, and 2014, 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 ETP Holdco, Oasis Pipeline Company and until July 31, 2015, Susser Holding Corporation. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third-party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

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

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

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

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on interest rate derivatives" in the consolidated statements of operations.

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 within AOCI in equity or, for entities applying regulatory accounting, as a regulatory asset or regulatory liability.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the partners' capital balances reflected under GAAP in our consolidated financial statements. Our net income for partners' capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the IDRs pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2016 Transactions

PennTex Acquisition

On November 1, 2016, ETP acquired certain interests in PennTex from various parties for total consideration of approximately $627 million in ETP units and cash. Through this transaction, ETP acquired a controlling financial interest in PennTex, whose assets complement ETP's existing midstream footprint in northern Louisiana.

Summary of Assets Acquired and Liabilities Assumed

We accounted for the PennTex 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.

The total purchase price was allocated as follows:

	At November 1, 2016
Total current assets	$ 34
Property, plant and equipment	393
Goodwill[1]	177
Intangible assets	446
	1,050
Total current liabilities	6
Long-term debt, less current maturities	164
Other non-current liabilities	17
Noncontrolling interest	236
	423
Total consideration	627
Cash received	21
Total consideration, net of cash received	$ 606

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

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

Sunoco Logistics' Vitol Acquisition

In November 2016, Sunoco Logistics completed an acquisition from Vitol, Inc. ("Vitol") of an integrated crude oil business in West Texas for $760 million plus working capital. The acquisition provides Sunoco Logistics with an approximately 2 million barrel crude oil terminal in Midland, Texas, a crude oil gathering and mainline pipeline system in the Midland Basin, including a significant acreage dedication from an investment-grade Permian producer, and crude oil inventories related to Vitol's crude oil purchasing and marketing business in West Texas. The acquisition also included the purchase of a 50% interest in SunVit Pipeline LLC ("SunVit"), which increased Sunoco Logistics' overall ownership of SunVit to 100%. The $769 million purchase price, net of cash received, consisted primarily of net working capital of $13 million largely attributable to inventory and receivables; property, plant and equipment of $286 million primarily related to pipeline and terminalling assets; intangible assets of $313 million attributable to customer relationships; and goodwill of $251 million.

Sunoco Logistics' Permian Express Partners

In February 2017, Sunoco Logistics formed Permian Express Partners LLC ("PEP"), a strategic joint venture, with ExxonMobil Corp. Sunoco Logistics contributed its Permian Express 1, Permian Express 2 and Permian Longview and Louisiana Access pipelines. ExxonMobil Corp. contributed its Longview to Louisiana and Pegasus pipelines; Hawkins gathering system; an idle pipeline in southern Oklahoma; and its Patoka, Illinois terminal. Sunoco Logistics' ownership percentage is approximately 85%. Upon commencement of operations on the Bakken Pipeline, Sunoco Logistics will contribute its investment in the project, with a corresponding increase in its ownership percentage in PEP. Sunoco Logistics maintains a controlling financial and voting interest in PEP and is the operator of all of the assets. As such, PEP will be reflected as a consolidated subsidiary of Sunoco Logistics. ExxonMobil Corp.'s interest will be reflected as noncontrolling interest in Sunoco Logistics' consolidated balance sheet.

Bakken Equity Sale

On August 2, 2016, Bakken Holdings Company LLC, an entity in which ETP indirectly owns a 60% membership interest and Sunoco Logistics indirectly owns a 40% membership interest, agreed to sell a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by Marathon Petroleum Corporation and Enbridge Energy Partners, L.P. for $2.00 billion in cash. This transaction closed in February 2017. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access, LLC ("Dakota Access") and Energy Transfer Crude Oil Company, LLC ("ETCO"). The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. ETP will continue to consolidate Dakota Access and ETCO subsequent to this transaction. Upon closing, ETP and Sunoco Logistics collectively own a 38.25% interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline projects (collectively, the "Bakken Pipeline"), and MarEn Bakken Company owns 36.75% and Phillips 66 owns 25.00% in the Bakken Pipeline.

Bakken Financing

In August 2016, ETP, Sunoco Logistics and Phillips 66 announced the completion of the project-level financing of the Bakken Pipeline. The $2.50 billion credit facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects. As of December 31, 2016, $1.10 billion was outstanding under this credit facility.

Bayou Bridge

In April 2016, Bayou Bridge Pipeline, LLC ("Bayou Bridge"), a joint venture among ETP, Sunoco Logistics and Phillips 66 Partners LP, began commercial operations on the 30-inch segment of the pipeline from Nederland, Texas to Lake Charles, Louisiana. ETP and Sunoco Logistics each hold a 30% interest in the entity and Sunoco Logistics is the operator of the system.

Sunoco Retail to Sunoco LP

In March 2016, ETP contributed to Sunoco LP its remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP paid $2.20 billion in cash, including a working capital adjustment and issued 5.7 million Sunoco LP common units to Retail Holdings, a wholly-owned subsidiary of the Partnership. The transaction was effective January 1, 2016. In connection with this transaction, the Partnership deconsolidated the legacy Sunoco, Inc. retail business, including goodwill of $1.29 billion and intangible assets of $294 million. The results of Sunoco, LLC and the legacy Sunoco, Inc. retail business' operations have not been presented as discontinued operations and Sunoco, Inc.'s retail business assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements.

Following is a summary of amounts reflected for the prior periods in ETP's consolidated statements of operations related to Sunoco, LLC and the legacy Sunoco, Inc. retail business, which operations are no longer consolidated for the current period in 2016:

	Years Ended December 31,	
	2015	2014
Revenues	$ 12,482	$ 22,487
Cost of products sold	11,174	21,155
Operating expenses	798	727
Selling, general and administrative expenses	106	99

2015 Transactions

Sunoco LP

In April 2015, Sunoco LP acquired a 31.58% equity interest in Sunoco, LLC from Retail Holdings for $816 million. Sunoco, LLC distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest regions of the United States. Sunoco LP paid $775 million in cash and issued $41 million of Sunoco LP common units to Retail Holdings, based on the five-day volume weighted average price of Sunoco LP's common units as of March 20, 2015.

In July 2015, in exchange for the contribution of 100% of Susser from ETP to Sunoco LP, Sunoco LP paid $970 million in cash and issued to ETP subsidiaries 22 million Sunoco LP Class B units valued at $970 million. The Sunoco Class B units did not receive second quarter 2015 cash distributions from Sunoco LP and converted on a one-for-one basis into Sunoco LP common units on the day immediately following the record date for Sunoco LP's second quarter 2015 distribution. In addition, (i) a Susser subsidiary exchanged its 79,308 Sunoco LP common units for 79,308 Sunoco LP Class A units, (ii) 10.9 million Sunoco LP subordinated units owned by Susser subsidiaries were converted into 10.9 million Sunoco LP Class A units and (iii) Sunoco LP issued 79,308 Sunoco LP common units and 10.9 million Sunoco LP subordinated units to subsidiaries of ETP. The Sunoco LP Class A units owned by the Susser subsidiaries were contributed to Sunoco LP as part of the transaction. Sunoco LP subsequently contributed its interests in Susser to one of its subsidiaries.

Effective July 1, 2015, ETE acquired 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, and in exchange, ETP repurchased from ETE 31.5 million ETP common units owned by ETE (the "Sunoco LP Exchange"). In connection with ETP's 2014 acquisition of Susser, ETE agreed to provide ETP a $35 million annual IDR subsidy for 10 years, which terminated upon the closing of ETE's acquisition of Sunoco GP. In connection with the exchange and repurchase, ETE will provide ETP a $35 million annual IDR subsidy for two years beginning with the quarter ended September 30, 2015. In connection with this transaction, the Partnership deconsolidated Sunoco LP, including goodwill of $1.81 billion and intangible assets of $982 million related to Sunoco LP. The Partnership continues to hold 37.8 million Sunoco LP common units accounted for under the equity method. The results of Sunoco LP's operations have not been presented as discontinued operations and Sunoco LP's assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements.

Bakken Pipeline

In March 2015, ETE transferred 46.2 million Partnership common units, ETE's 45% interest in the Bakken Pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued 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, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to ETP. These IDR subsidies, including the impact from distributions on Class I Units, were reduced by $55 million in 2015 and $30 million in 2016.

In October 2015, Sunoco Logistics completed the previously announced acquisition of a 40% membership interest (the "Bakken Membership Interest") in Bakken Holdings Company LLC ("Bakken Holdco"). Bakken Holdco, through its wholly-owned subsidiaries, owns a 75% membership interest in each of Dakota Access, LLC and Energy Transfer Crude Oil Company, LLC, which together intend to develop the Bakken Pipeline system to deliver crude oil from the Bakken/Three Forks production area in North Dakota to the Gulf Coast. ETP transferred the Bakken Membership Interest to Sunoco Logistics in exchange for approximately 9.4 million Class B Units representing limited partner interests in Sunoco Logistics and the payment by Sunoco Logistics to ETP of $382 million of cash, which represented reimbursement for its proportionate share of the total cash contributions made in the Bakken Pipeline project as of the date of closing of the exchange transaction.

Regency Merger

On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency, with Regency surviving as a wholly-owned subsidiary of the Partnership (the "Regency Merger"). Each Regency common unit and Class F unit was converted into the right to receive 0.6186 Partnership common units. ETP issued 258.3 million Partnership common units to Regency unitholders, including 23.3 million units issued to Partnership subsidiaries. The 1.9 million outstanding Regency series A preferred units were converted into corresponding new Partnership Series A Preferred Units on a one-for-one basis.

In connection with the Regency Merger, ETE agreed to reduce the incentive distributions it receives from the Partnership by a total of $320 million over a five-year period. The IDR subsidy was $80 million for the year ended December 31, 2015 and will total $60 million per year for the following four years.

The Regency Merger was a combination of entities under common control; therefore, Regency's assets and liabilities were not adjusted. The Partnership's consolidated financial statements have been retrospectively adjusted to reflect consolidation of Regency for all prior periods subsequent to May 26, 2010 (the date ETE acquired Regency's general partner). Predecessor equity included on the consolidated financial statements represents Regency's equity prior to the Regency Merger.

ETP has assumed all of the obligations of Regency and Regency Energy Finance Corp., of which ETP was previously a co-obligor or parent guarantor.

2014 Transactions

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.

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 23.7 million ETP Common Units. The Susser Merger broadens our 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.

The following table summarizes the 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 were 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, as the impact of these acquisitions was not material in relation to ETP's consolidated results of operations.

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. 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.

The total purchase price was allocated as follows:

Assets	At July 1, 2014
Current assets	$ 120
Property, plant and equipment	1,295
Other non-current assets	4
Goodwill	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

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 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. 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.

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(1)	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

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

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

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 28.1 million ETP Common Units held by ETE (the "Lake Charles LNG Transaction"). This transaction was effective as of January 1, 2014, at which time ETP deconsolidated Lake Charles LNG, including goodwill of $184 million and intangible assets of $50 million related to Lake Charles LNG. The results of Lake Charles LNG's operations have not been presented as discontinued operations and Lake Charles LNG's assets and liabilities have not been presented as held for sale in the Partnership's consolidated financial statements due to the continuing involvement among the entities.

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 8.

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 common units and 6.3 million Class F Units, all of which have subsequently converted into ETP common units), and ETP (3.3 million Common Units).

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

The carrying values of the Partnership's investments in unconsolidated affiliates as of December 31, 2016 and 2015 were as follows:

	December 31,	
	2016	2015
Citrus	$ 1,729	$ 1,739
AmeriGas	82	80
FEP	101	115
MEP	318	660
HPC	382	402
Sunoco LP	1,225	1,380
Others	443	627
Total	$ 4,280	$ 5,003

Citrus

ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of KMI. Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

AmeriGas

In 2012, we received 29.6 million AmeriGas common units in connection with the contribution of our propane operations. During the year ended December 31, 2014, we sold 18.9 million AmeriGas common units for net proceeds of $814 million. As of December 31, 2016, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company and is reflected in the all other segment.

FEP

We have a 50% interest in FEP which owns 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. Our investment in FEP is reflected in the interstate transportation and storage segment.

MEP

We own a 50% interest in MEP, which owns approximately 500 miles of natural gas pipeline that extends from Southeast Oklahoma, across Northeast Texas, Northern Louisiana and Central Mississippi to an interconnect with the Transcontinental natural gas pipeline system in Butler, Alabama. Our investment in MEP is reflected in the interstate transportation and storage segment. The Partnership evaluated its investment in MEP for impairment as of September 30, 2016, based on FASB Accounting Standards Codification 323, *Investments - Equity Method and Joint Ventures*. Based on commercial discussions with current and potential shippers on MEP regarding the outlook for long-term transportation contract rates, the Partnership concluded that the fair value of its investment was other than temporarily impaired, resulting in a non-cash impairment of $308 million during the year ended December 31, 2016.

HPC

We own 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. Our investment in HPC is reflected in the intrastate transportation and storage segment.

Sunoco LP

Effective July 1, 2015, ETE acquired 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from the Partnership. As a result, the Partnership deconsolidated Sunoco LP, and its remaining investment in Sunoco LP is accounted for under the equity method. As of December 31, 2016, the Partnership's interest in Sunoco LP common units consisted of 43.5 million units, representing 44.3% of Sunoco LP's total outstanding common units, and is reflected in the all other segment.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, AmeriGas, Citrus, FEP, HPC, MEP and Sunoco LP (on a 100% basis) for all periods presented:

	December 31, 2016	December 31, 2015
Current assets	$ 2,109	$ 1,646
Property, plant and equipment, net	13,355	12,611
Other assets	6,557	5,485
Total assets	$ 22,021	$ 19,742
Current liabilities	$ 2,547	$ 1,517
Non-current liabilities	12,899	10,428
Equity	6,575	7,797
Total liabilities and equity	$ 22,021	$ 19,742

	Years Ended December 31, 2016	2015	2014
Revenue	$ 19,207	$ 20,961	$ 4,925
Operating income	933	1,620	1,071
Net income	196	894	577

In addition to the equity method investments described above we have other equity method investments which are not significant to our consolidated financial statements.

5. NET INCOME (LOSS) PER LIMITED PARTNER UNIT:

The following table provides a reconciliation of the numerator and denominator of the basic and diluted income (loss) per unit.

The historical common units and net income (loss) per limited partner unit amounts presented in these consolidated financial statements have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

	Years Ended December 31,		
	2016	2015	2014
Income from continuing operations	$ 624	$ 1,521	$ 1,235
Less: Income from continuing operations attributable to noncontrolling interest	327	157	116
Less: Loss from continuing operations attributable to predecessor	—	(34)	(153)
Income from continuing operations, net of noncontrolling interest	297	1,398	1,272
General Partner's interest in income from continuing operations	948	1,064	513
Class H Unitholder's interest in income from continuing operations	351	258	217
Class I Unitholder's interest in income from continuing operations	8	94	—
Common Unitholders' interest in income (loss) from continuing operations	(1,010)	(18)	542
Additional earnings allocated to General Partner	(10)	(5)	(4)
Distributions on employee unit awards, net of allocation to General Partner	(19)	(16)	(13)
Income (loss) from continuing operations available to Common Unitholders	$ (1,039)	$ (39)	$ 525
Weighted average Common Units – basic	758.2	649.2	497.2
Basic income (loss) from continuing operations per Common Unit	$ (1.37)	$ (0.06)	$ 1.05
Income (loss) from continuing operations available to Common Unitholders	$ (1,039)	$ (39)	$ 525
Loss attributable to ETP Series A Preferred Units	—	(6)	—
	$ (1,039)	$ (45)	$ 525
Weighted average Common Units – basic	758.2	649.2	497.2
Dilutive effect of unvested Unit Awards	—	—	2.0
Dilutive effect of Preferred Units	—	1.0	—
Weighted average Common Units – diluted	758.2	650.2	499.2
Diluted income (loss) from continuing operations per Common Unit	$ (1.37)	$ (0.07)	$ 1.05
Basic income from discontinued operations per Common Unit	$ —	$ —	$ 0.13
Diluted income from discontinued operations per Common Unit	$ —	$ —	$ 0.13

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31,	
	2016	2015
ETP Debt		
6.125% Senior Notes due February 15, 2017	$ 400	$ 400
2.50% Senior Notes due June 15, 2018	650	650
6.70% Senior Notes due July 1, 2018	600	600
9.70% Senior Notes due March 15, 2019	400	400

9.00% Senior Notes due April 15, 2019	450	450
5.75% Senior Notes due September 1, 2020	400	400
4.15% Senior Notes due October 1, 2020	1,050	1,050
6.50% Senior Notes due July 15, 2021	500	500
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
5.875% Senior Notes due March 1, 2022	900	900
5.00% Senior Notes due October 1, 2022	700	700
3.60% Senior Notes due February 1, 2023	800	800
5.50% Senior Notes due April 15, 2023	700	700
4.50% Senior Notes due November 1, 2023	600	600
4.90% Senior Notes due February 1, 2024	350	350
7.60% Senior Notes due February 1, 2024	277	277
4.05% Senior Notes due March 15, 2025	1,000	1,000
4.75% Senior Notes due January 15, 2026	1,000	1,000
8.25% Senior Notes due November 15, 2029	267	267
4.90% Senior Notes due March 15, 2035	500	500
6.625% Senior Notes due October 15, 2036	400	400
7.50% Senior Notes due July 1, 2038	550	550
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
5.15% Senior Notes due February 1, 2043	450	450
5.95% Senior Notes due October 1, 2043	450	450
5.15% Senior Notes due March 15, 2045	1,000	1,000
6.125% Senior Notes due December 15, 2045	1,000	1,000
Floating Rate Junior Subordinated Notes due November 1, 2066	546	545
ETP $3.75 billion Revolving Credit Facility due November 2019	2,777	1,362
Unamortized premiums, discounts and fair value adjustments, net	(18)	(21)
Deferred debt issuance costs	(132)	(147)
	22,067	20,633
Transwestern Debt		
5.54% Senior Notes due November 17, 2016	—	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)
Deferred debt issuance costs	(1)	(2)
	656	779
Panhandle Debt		
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 15, 2029	33	33
Floating Rate Junior Subordinated Notes due November 1, 2066	54	54
Unamortized premiums, discounts and fair value adjustments, net	50	75
	1,135	1,160
Sunoco, Inc. Debt		
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	9	20
	474	485
Sunoco Logistics Debt		
6.125% Senior Notes due May 15, 2016	—	175
5.50% Senior Notes due February 15, 2020	250	250

4.40% Senior Notes due April 1, 2021	600	600
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	500
5.95% Senior Notes due December 1, 2025	400	400
3.90% Senior Notes due July 15, 2026	550	—
6.85% Senior Notes due February 15, 2040	250	250
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	350
5.30% Senior Notes due April 1, 2044	700	700
5.35% Senior Notes due May 15, 2045	800	800
Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020	1,292	562
Sunoco Logistics $1.0 billion 364-Day Credit Facility due December 2017[(1)]	630	—
Unamortized premiums, discounts and fair value adjustments, net	75	85
Deferred debt issuance costs	(34)	(32)
	7,313	5,590
Bakken Project Debt		
Bakken Project $2.50 billion Credit Facility due August 2019	1,100	—
Deferred debt issuance costs	(13)	—
	1,087	—
PennTex Debt		
PennTex $275 million Revolving Credit Facility due December 2019	168	—
Other	30	32
	32,930	28,679
Less: current maturities	1,189	126
	$ 31,741	$ 28,553

(1) Sunoco Logistics' $1.0 billion 364-Day Credit Facility, including its $630 million term loan, were classified as long-term debt as of December 31, 2016 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 $64 million in unamortized net premiums, fair value adjustments and deferred debt issuance costs:

2017	$ 1,812
2018	1,650
2019	5,045
2020	3,167
2021	1,900
Thereafter	19,420
Total	$ 32,994

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.

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 $465 million as of December 31, 2016, and $400 million matured and was repaid in January 2017.

ETP Senior Notes Offerings

In January 2017, ETP issued $600 million aggregate principal amount of 4.20% senior notes due April 2027 and $900 million aggregate principal amount of 5.30% senior notes due April 2047. ETP used the $1.48 billion net proceeds from the offering to refinance current maturities and to repay borrowings outstanding under the ETP Credit Facility.

The ETP senior notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP senior notes. The balance is payable upon maturity. Interest on the ETP senior notes is paid semi-annually.

The ETP senior notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP senior notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP senior notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP senior notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

Transwestern Senior Notes

The Transwestern senior notes are redeemable at any time in whole or pro rata, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

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 3.77% at December 31, 2016.

Sunoco Logistics Senior Notes Offerings

In July 2016, Sunoco Logistics issued $550 million aggregate principal amount of 3.90% senior notes due in July 2026. The net proceeds from this offering were used to repay outstanding credit facility borrowings and for general partnership purposes.

Credit Facilities and Commercial Paper

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $3.75 billion and matures on November 18, 2019. The indebtedness under the ETP Credit Facility is unsecured, is not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt. We use the ETP Credit Facility to provide temporary financing for our growth projects, as well as for general partnership purposes.

As of December 31, 2016, the ETP Credit Facility had $2.78 billion outstanding, and the amount available for future borrowings was $813 million after taking into account letters of credit of $160 million and commercial paper of $777 million. The weighted average interest rate on the total amount outstanding as of December 31, 2016 was 2.20%.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $2.50 billion unsecured revolving credit agreement (the "Sunoco Logistics Credit Facility"), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $3.25 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, based on Sunoco Logistics' election for each interest period, plus an applicable margin. The credit facility may be prepaid at any time. As of December 31, 2016, the Sunoco Logistics Credit Facility had $1.29 billion of outstanding borrowings, which included commercial paper of $50 million. The weighted average interest rate on the total amount outstanding as of December 31, 2016 was 1.76%.

In December 2016, Sunoco Logistics entered into an agreement for a 364-day maturity credit facility ("364-Day Credit Facility"), due to mature in December 2017, with a total lending capacity of $1.00 billion, including a $630 million term loan. The terms of the 364-Day Credit Facility are similar to those of the $2.50 billion Sunoco Logistics Credit Facility, including limitations on the creation of indebtedness, liens and financial covenants. The 364-Day Credit Facility is expected to be terminated and repaid in connection with the completion of the ETP and Sunoco Logistics merger.

Bakken Credit Facility

In August 2016, ETP, Sunoco Logistics and Phillips 66 announced the completion of the project-level financing of the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline projects (collectively, the “Bakken Pipeline”). The $2.50 billion credit facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects and matures in August 2019 (the “Bakken Credit Facility”). As of December 31, 2016, the Bakken Credit Facility had $1.10 billion of outstanding borrowings. The weighted average interest rate on the total amount outstanding as of December 31, 2016 was 2.13%.

PennTex Revolving Credit Facility

On December 19, 2014, PennTex entered into a senior secured revolving credit facility with Royal Bank of Canada, as administrative agent, and a syndicate of lenders that became effective upon the closing of PennTex’s initial public offering and matures in December 2019 (the “PennTex Revolving Credit Facility”). The agreement provides for a $275 million commitment that is expandable up to $400 million under certain conditions. The funds have been used for general purposes, including the funding of capital expenditures. PennTex’s assets have been pledged as collateral for this credit facility.

As of December 31, 2016, PennTex had $106 million of available borrowing capacity under the PennTex Revolving Credit Facility. As of December 31, 2016, the weighted average interest rate on outstanding borrowings was 2.90%.

Covenants Related to Our Credit Agreements

Covenants Related to ETP

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

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

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

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

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

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies’ ability to incur additional debt and/or our ability to pay distributions.

Covenants Related to 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

The Sunoco Logistics 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 Sunoco Logistics Credit Facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total Consolidated Funded Indebtedness to Consolidated EBITDA ratio, each as defined in the Sunoco Logistics Credit Facility, 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 Funded Indebtedness, excluding net unamortized fair value adjustments, to Consolidated EBITDA was 4.4 to 1 at December 31, 2016, as calculated in accordance with the credit agreements.

Covenants Related to Bakken Credit Facility

The Bakken Credit Facility contains standard and customary covenants for a financing of this type, subject to materiality, knowledge and other qualifications, thresholds, reasonableness and other exceptions. These standard and customary covenants include, but are not limited to:

- prohibition of certain incremental secured indebtedness;
- prohibition of certain liens / negative pledge;
- limitations on uses of loan proceeds;
- limitations on asset sales and purchases;
- limitations on permitted business activities;
- limitations on mergers and acquisitions;
- limitations on investments;
- limitations on transactions with affiliates; and
- maintenance of commercially reasonable insurance coverage.

A restricted payment covenant is also included in the Bakken Credit Facility which requires a minimum historic debt service coverage ratio ("DSCR") of not less than 1.20 to 1 (the "Minimum Historic DSCR") with respect each 12-month period following the commercial in-service date of the Dakota Access and ETCO Project in order to make certain restricted payments thereunder.

Covenants Related to PennTex

The PennTex Revolving Credit Facility contains various covenants and restrictive provisions that, among other things, limit or restrict PennTex's ability to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions (including distributions from available cash, if a default or event of default under the credit agreement then exists or would result from making such a distribution), change the nature of PennTex's business, engage in certain mergers or make certain investments and acquisitions, enter into non-arm's-length transactions with affiliates and designate certain subsidiaries of PennTex as "Unrestricted Subsidiaries" for purposes of the credit agreement. Currently, no subsidiaries have been designated as Unrestricted Subsidiaries. PennTex is required to comply with a minimum consolidated interest coverage ratio of 2.50x and a maximum consolidated leverage ratio of 4.75x under the PennTex Revolving Credit Facility.

The borrowed amounts accrue interest at a LIBOR rate or a base rate, based on PennTex's election for each interest period, plus an applicable margin. The applicable margin used in connection with the interest rates and fees is based on the then applicable Consolidated Total Leverage Ratio (as defined therein). The applicable margin for LIBOR rate loans and letter of credit fees range from 2.00% and 3.25% based on the Consolidated Total Leverage Ratio and the applicable margin for ABR loans ranges from 1.00% to 2.25% based on the Consolidated Total Leverage Ratio. The unused portion of the credit facility is subject to a commitment fee, which is based on the Consolidated Total Leverage Ratio and ranges from 0.35% to 0.50% multiplied by the amount of the unused commitment.

Compliance with our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2016.

7. SERIES A PREFERRED UNITS:

The Series A Preferred Units are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon and are reflected as long-term liabilities in our consolidated balance sheets. The Preferred Units are entitled to a preferential quarterly cash distribution of $0.445 per Preferred Unit if outstanding on the record dates of the Partnership's common unit distributions. Holders of the Preferred Units can elect to convert the ETP Preferred Units to ETP Common Units at any time in accordance with ETP's partnership agreement. The number of common units issuable upon conversion of the Preferred Units is equal to the issue price of $18.30, plus all accrued but unpaid distributions and interest thereon, divided by the conversion price of $44.37. As of December 31, 2016, the Preferred Units were convertible into 1.3 million ETP Common Units.

In January 2017, ETP repurchased all of its 1.9 million outstanding Series A Preferred Units for cash in the aggregate amount of $53 million.

8. EQUITY:

Limited Partner interests are represented by Common, Class E Units, Class G Units, Class H and Class I Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

IDRs represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash (as defined in our Partnership Agreement) from operating surplus after the minimum quarterly distribution has been paid. Please read "Quarterly Distributions of Available Cash" below. ETP GP, a wholly-owned subsidiary of ETE, owns all of the IDRs.

Common Units

The change in Common Units was as follows:

	Years Ended December 31,		
	2016 [1]	2015 [1]	2014 [1]
Number of Common Units, beginning of period	758.5	533.4	500.9
Common Units redeemed in connection with certain transactions	(26.7)	(77.8)	(28.1)
Common Units issued in connection with certain acquisitions	13.3	258.2	23.7
Common Units issued in connection with the Distribution Reinvestment Plan	9.9	11.7	4.2
Common Units issued in connection with Equity Distribution Agreements	39.0	31.7	32.2
Issuance of Common Units under equity incentive plans	0.8	1.3	0.5
Number of Common Units, end of period	794.8	758.5	533.4

(1) The historical common units presented have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

Our Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under “Quarterly Distributions of Available Cash.”

Equity Distribution Program

From time to time, we have sold Common Units through equity distribution agreements. Such sales of Common Units are made by means of ordinary brokers’ transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and the sales agent which is the counterparty to the equity distribution agreements.

In July 2016, the Partnership entered into an equity distribution agreement with an aggregate offering price up to $1.50 billion. During the year ended December 31, 2016, we issued 39.2 million units for $891 million, net of commissions of $8 million. In connection with the merger of ETP and Sunoco Logistics in April 2017, the equity distribution agreement was terminated.

Equity Incentive Plan Activity

We issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Distribution Reinvestment Program

Our Distribution Reinvestment Plan (the “DRIP”) provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units.

During the years ended December 31, 2016, 2015 and 2014, aggregate distributions of $216 million, $360 million, and $155 million, respectively, were reinvested under the DRIP resulting in the issuance in aggregate of 25.7 million Common Units. In connection with the merger of ETP and Sunoco Logistics in April 2017, the distribution reinvestment plan was terminated.

January 2017 Private Placement

In January 2017, the Partnership sold 23.7 million ETP Common Units to ETE in a private placement transaction for gross proceeds of approximately $568 million.

Class E Units

The Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year, with any excess thereof available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests. The Class E Units are treated as treasury units for accounting purposes because they are owned by a subsidiary of ETP Holdco, Heritage Holdings, Inc. Although no plans are currently in place, management may evaluate whether to retire some or all of the Class E Units at a future date. All of the 8.9 million Class E Units outstanding are held by a subsidiary and are reported as treasury units.

Class G Units

In conjunction with the Sunoco Merger, we amended our partnership agreement to create Class F Units. The number of Class F Units issued was determined at the closing of the Sunoco Merger and equaled 90.7 million, which included 40 million Class F Units issued in exchange for cash contributed by Sunoco, Inc. to us immediately prior to or concurrent with the closing of the Sunoco Merger. The Class F Units generally did not have any voting rights. The Class F Units were entitled to aggregate cash distributions equal to 35% of the total amount of cash generated by us and our subsidiaries, other than ETP Holdco, and available for distribution, up to a maximum of $3.75 per Class F Unit per year. In April 2013, all of the outstanding Class F Units were exchanged for Class G Units on a one-for-one basis. The Class G Units have terms that are substantially the same as the Class F Units, with the principal difference between the Class G Units and the Class F Units being that allocations of depreciation and amortization to the Class G Units for tax purposes are based on a predetermined percentage and are not contingent on whether ETP has net income or loss. These units are held by a subsidiary and therefore are reflected as treasury units in the consolidated financial statements.

Class H Units and Class I Units

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the “Redeemed Units”) owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the “Class H Units”), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 90.05% 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 and (ii) distributions from available cash at ETP for each quarter equal to 90.05% 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. The Class H Units were cancelled in connection with the merger of ETP and Sunoco Logistics in April 2017.

Bakken Pipeline Transactions

In March 2015, ETE transferred 46.2 million Partnership common units, ETE’s 45% interest in the Bakken Pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued 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, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to ETP. These IDR subsidies, including the impact from distributions on Class I Units, were reduced by $55 million in 2015 and $30 million in 2016.

In connection with the transaction, ETP issued 100 Class I Units. The 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 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 Class I Units and (ii) after making cash distributions to 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 Class I Units in an amount equal to the excess of the distribution amount set forth in our 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 “Quarterly Distributions of Available Cash.” Subsequent to the April 2017 merger of ETP and Sunoco Logistics, 100 Class I Units remained outstanding.

Bakken Equity Sale

On August 2, 2016, Bakken Holdings Company LLC, an entity in which ETP indirectly owns a 60% membership interest and Sunoco Logistics indirectly owns a 40% membership interest, agreed to sell a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by Marathon Petroleum Corporation and Enbridge Energy Partners, L.P. for $2.00 billion in cash. This transaction closed in February 2017. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access, LLC ("Dakota Access") and Energy Transfer Crude Oil Company, LLC ("ETCO"). The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. ETP will continue to consolidate Dakota Access and ETCO subsequent to this transaction. Upon closing, ETP and Sunoco Logistics collectively own a 38.25% interest in the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline projects (collectively, the "Bakken Pipeline"), and MarEn Bakken Company owns 36.75% and Phillips 66 owns 25.00% in the Bakken Pipeline.

Class K Units

On December 29, 2016, the Partnership issued to certain of its indirect subsidiaries, in exchange for cash contributions and the exchange of outstanding common units representing limited partner interests in the Partnership, Class K Units, each of which is entitled to a quarterly cash distribution of $0.67275 per Class K Unit prior to ETP making distributions of available cash to any class of units other than the Class H Units and the Class I Units, excluding any cash available distributions or dividends or capital stock sales proceeds received by ETP from ETP Holdco. As of December 31, 2016, a total of 101,525,429 Class K Units were held by indirect subsidiaries of ETP.

Sales of Common Units by Sunoco Logistics

With respect to our investment in Sunoco Logistics, we account for the difference between the carrying amount of our investment in and the underlying book value arising from the issuance or redemption of units by the respective subsidiary (excluding transactions with us) as capital transactions.

As a result of Sunoco Logistics' issuances of common units during the year ended December 31, 2016, we recognized increases in partners' capital of $37 million.

In September and October 2016, a total of 24.2 million common units were issued for net proceeds of $644 million in connection with a public offering and related option exercise. The proceeds from this offering were used to partially fund the acquisition from Vitol.

In March and April 2015, a total of 15.5 million common units were issued in connection with a public offering and related option exercise. Net proceeds of $629 million were used to repay outstanding borrowings under Sunoco Logistics' $2.50 billion Credit Facility and for general partnership purposes.

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

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. In the fourth quarter of 2015, the aggregate capacity was increased to $2.25 billion. During the year ended December 31, 2016, Sunoco Logistics received proceeds of $744 million, net of commissions of $8 million, from the issuance of 29.1 million common units pursuant to the equity distribution agreement.

Quarterly Distributions of Available Cash

The Partnership Agreement requires that we distribute all of our Available Cash to our Unitholders and our General Partner within forty-five days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any of our fiscal quarters, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of our business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in our Partnership Agreement.

Our distributions of Available Cash from operating surplus, excluding incentive distributions, to our General Partner and Limited Partner interests are based on their respective interests as of the distribution record date. Incentive distributions allocated to our General Partner are determined based on the amount by which quarterly distribution to common Unitholders exceed certain specified target levels, as set forth in our Partnership Agreement.

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2013	February 7, 2014	February 14, 2014	$ 0.6133
March 31, 2014	May 5, 2014	May 15, 2014	0.6233
June 30, 2014	August 4, 2014	August 14, 2014	0.6367
September 30, 2014	November 3, 2014	November 14, 2014	0.6500
December 31, 2014	February 6, 2015	February 13, 2015	0.6633
March 31, 2015	May 8, 2015	May 15, 2015	0.6767
June 30, 2015	August 6, 2015	August 14, 2015	0.6900
September 30, 2015	November 5, 2015	November 16, 2015	0.7033
December 31, 2015	February 8, 2016	February 16, 2016	0.7033
March 31, 2016	May 6, 2016	May 16, 2016	0.7033
June 30, 2016	August 8, 2016	August 15, 2016	0.7033
September 30, 2016	November 7, 2016	November 14, 2016	0.7033
December 31, 2016	February 7, 2017	February 14, 2017	0.7033

ETE agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units:

	Total Year
2017	$ 626
2018	138
2019	128
Each year beyond 2019	33

Sunoco Logistics Quarterly Distributions of Available Cash

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
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
March 31, 2015	May 11, 2015	May 15, 2015	0.4190
June 30, 2015	August 10, 2015	August 14, 2015	0.4380
September 30, 2015	November 9, 2015	November 13, 2015	0.4580
December 31, 2015	February 8, 2016	February 12, 2016	0.4790
March 31, 2016	May 9, 2016	May 13, 2016	0.4890
June 30, 2016	August 8, 2016	August 12, 2016	0.5000
September 30, 2016	November 9, 2016	November 14, 2016	0.5100
December 31, 2016	February 7, 2017	February 14, 2017	0.5200

PennTex Quarterly Distributions of Available Cash

PennTex is required by its partnership agreement to distribute a minimum quarterly distribution of $0.2750 per unit at the end of each quarter. Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2016	November 7, 2016	November 14, 2016	$ 0.2950
December 31, 2016	February 7, 2017	February 14, 2017	0.2950

Accumulated Other Comprehensive Income

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

	December 31,	
	2016	2015
Available-for-sale securities	$ 2	$ —
Foreign currency translation adjustment	(5)	(4)
Actuarial gain related to pensions and other postretirement benefits	7	8
Investments in unconsolidated affiliates, net	4	—
Total AOCI, net of tax	$ 8	$ 4

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

	December 31,	
	2016	2015
Available-for-sale securities	$ (2)	$ (2)
Foreign currency translation adjustment	3	4
Actuarial loss relating to pension and other postretirement benefits	—	7
Total	$ 1	$ 9

9. UNIT-BASED COMPENSATION PLANS:

ETP Unit-Based Compensation Plan

We have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, Common Units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2016, an aggregate total of 2.7 million ETP Common Units remain available to be awarded under our equity incentive plans.

Restricted Units

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. We refer to these rights as "distribution equivalent rights." Under our equity incentive plans, our non-employee directors each receive grants with a five-year service vesting requirement.

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2015	7.2	$ 31.74
Awards granted	3.8	23.82
Awards vested	(1.2)	35.48
Awards forfeited	(0.3)	32.26
Unvested awards as of December 31, 2016	9.5	27.69

During the years ended December 31, 2016, 2015, and 2014, the weighted average grant-date fair value per unit award granted was $23.82, $23.47 and $40.57, respectively. The total fair value of awards vested was $28 million, $49 million and $26 million, respectively, based on the market price of ETP Common Units as of the vesting date. As of December 31, 2016, a total of 9.5 million unit awards remain unvested, for which ETP expects to recognize a total of $179 million in compensation expense over a weighted average period of 2.1 years.

Cash Restricted Units. The Partnership 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, 2016, a total of 0.4 million unvested cash restricted units were outstanding.

Based on the trading price of ETP Common Units at December 31, 2016, the Partnership expects to recognize $3 million of unit-based compensation expense related to non-vested cash restricted units over a period of 1.0 year.

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, phantom unit awards, unit appreciation rights, unrestricted unit awards and other unit-based awards.

Restricted Units

Sunoco Logistics has granted restricted unit awards to employees and directors that entitle the grantees to receive Sunoco Logistics common units or, at the discretion of the Sunoco Logistics compensation committee, an amount of cash equivalent to the value of common units upon vesting. Sunoco Logistics' outstanding restricted unit awards are time-vested grants, the vesting of which occurs over a five-year period, and is conditioned solely upon continued employment or service as of the applicable vesting date. These unit awards entitle the grantees of the unit awards to receive an amount of cash equal to the per unit cash distributions made by Sunoco Logistics during the period the restricted unit is outstanding.

The following table summarizes the activity of the Sunoco Logistics restricted unit awards:

	Number of Sunoco Logistics Units	Weighted Average Grant-Date Fair Value Per Sunoco Logistics Unit
Unvested awards as of December 31, 2015	2.5	$ 33.16
Awards granted	1.3	23.21
Awards vested	(0.5)	34.19
Awards forfeited	(0.1)	33.72
Unvested awards as of December 31, 2016	3.2	28.57

During the years ended December 31, 2016, 2015 and 2014, the weighted average grant-date fair value per unit award granted was $23.21, $29.54 and $41.59, respectively. The total fair value of restricted unit awards vested for the years ended December 31, 2016, 2015 and 2014, was $12 million, $8 million, and $30 million, respectively, based on the market price of Sunoco Logistics' common units as of the vesting date. As of December 31, 2016, estimated compensation cost related to non-vested awards not yet recognized was $57 million, and the weighted average period over which this cost is expected to be recognized in expense is 3.0 years.

10. INCOME TAXES:

As a partnership, we are not subject to U.S. federal income tax and most state income taxes. However, the Partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) are summarized as follows:

	Years Ended December 31,		
	2016	2015	2014
Current expense (benefit):			
Federal	$ 18	$ (274)	$ 321
State	(35)	(51)	86
Total	(17)	(325)	407
Deferred expense (benefit):			
Federal	(173)	231	(50)
State	4	(29)	1
Total	(169)	202	(49)
Total income tax expense (benefit) from continuing operations	$ (186)	$ (123)	$ 358

Historically, our effective rate differed from the statutory rate primarily due to Partnership earnings that are not subject to U.S. federal and most state income taxes at the partnership level. The completion of the Southern Union Merger, Sunoco Merger, ETP Holdco Transaction and 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, 2016, 2015 and 2014 is as follows:

	Years Ended December 31,		
	2016	2015	2014
Income tax expense at U.S. statutory rate of 35 percent	$ 154	$ 490	$ 558
Increase (reduction) in income taxes resulting from:			
Partnership earnings not subject to tax	(519)	(515)	(341)
Nondeductible goodwill included in the Lake Charles LNG Transaction	—	—	105
Goodwill impairments	223	—	—
State income taxes (net of federal income tax effects)	(17)	(37)	54
Dividend Received Deduction	(15)	(24)	—
Audit Settlement	—	(7)	—
Premium on debt retirement	—	—	(10)
Foreign	—	—	(8)
Other	(12)	(30)	—
Income tax expense (benefit) from continuing operations	$ (186)	$ (123)	$ 358

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,	
	2016	2015
Deferred income tax assets:		
Net operating losses and alternative minimum tax credit	$ 380	$ 155
Pension and other postretirement benefits	30	36
Long term debt	32	61
Other	84	142
Total deferred income tax assets	526	394
Valuation allowance	(118)	(121)
Net deferred income tax assets	$ 408	$ 273
Deferred income tax liabilities:		
Properties, plants and equipment	$ (1,054)	$ (1,305)
Investment in unconsolidated affiliates	(3,728)	(2,889)
Trademarks	—	(112)
Other	(20)	(49)
Total deferred income tax liabilities	(4,802)	(4,355)
Accumulated deferred income taxes	$ (4,394)	$ (4,082)

The table below provides a rollforward of the net deferred income tax liability as follows:

	December 31,	
	2016	2015
Net deferred income tax liability, beginning of year	$ (4,082)	$ (4,331)
ETE Acquisition of general partner of Sunoco LP	—	490
Goodwill associated with Sunoco Retail to Sunoco LP transaction (see Note 3)	(460)	—
Tax provision	169	(202)
Other	(21)	(39)
Net deferred income tax liability, end of year	$ (4,394)	$ (4,082)

ETP Holdco and other corporate subsidiaries have federal net operating loss carryforward of $580 million, all of which will expire in 2032 through 2035. Our corporate subsidiaries have $52 million of federal alternative minimum tax credits at December 31, 2016. Our corporate subsidiaries have state net operating loss carryforward benefits of $124 million, net of federal tax, which expire between 2017 and 2036. A valuation allowance of $118 million is applicable to the state net operating loss carryforward benefits primarily attributable to significant restrictions on their use in the Commonwealth of Pennsylvania.

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

	Years Ended December 31,		
	2016	2015	2014
Balance at beginning of year	$ 610	$ 440	$ 429
Additions attributable to tax positions taken in the current year	8	—	20
Additions attributable to tax positions taken in prior years	18	178	—
Reduction attributable to tax positions taken in prior years	(20)	—	(1)
Settlements	—	—	(5)
Lapse of statute	(1)	(8)	(3)
Balance at end of year	$ 615	$ 610	$ 440

As of December 31, 2016, we have $596 million ($554 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 $1 million ($0.6 million, net of federal tax) within the next twelve months due to settlement of certain positions.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2016, we recognized interest and penalties of less than $1 million. At December 31, 2016, we have interest and penalties accrued of $6 million, net of tax.

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 years, Sunoco, Inc. filed amended returns with the IRS excluding these government incentive payments from federal taxable income. The IRS denied the amended returns, and Sunoco, Inc. petitioned the Court of Federal Claims ("CFC") in June 2015 on this issue. In November 2016, the CFC ruled against Sunoco, Inc., and Sunoco, Inc. is appealing this decision to the Federal Circuit. If Sunoco, Inc. is ultimately fully successful in this litigation, it will receive tax refunds of approximately $530 million. However, due to the uncertainty surrounding the litigation, a reserve of $530 million was established for the full amount of the litigation. Due to the timing of the litigation and the related reserve, the receivable and the reserve for this issue have been netted in the financial statements as of December 31, 2016.

In December of 2015, The Pennsylvania Commonwealth Court determined in *Nextel Communications v. Commonwealth* ("*Nextel*") that the Pennsylvania limitation on NOL carryforwards violated the uniformity clause of the Pennsylvania Constitution. Based upon the decision in *Nextel*, Sunoco, Inc. is recognizing approximately $46 million ($30 million after federal income tax benefits) in tax benefit based on previously filed tax returns and certain previously filed protective claims. However, as the *Nextel* decision is subject to appeal, and because of uncertainty in the breadth of the application of the decision, we have reserved $9 million ($6 million after federal income tax benefits) against the receivable.

In general, ETP and its subsidiaries are no longer subject to examination by the Internal Revenue Service ("IRS"), and most state jurisdictions, for the 2013 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.

Sunoco, Inc. has been examined by the IRS for tax years through 2013. However, 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 statute, 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.

ETP and its subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

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

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETP agreed to provide contingent residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third-party purchases. In 2016, AmeriGas repurchased certain of its senior notes, which caused a reduction in the amount supported by ETP under the contingent residual support agreement. In February 2017, AmeriGas repurchased $378 million of its 7.00% senior notes, which reduced the remaining amount supported by ETP to $122 million.

Guarantee of Sunoco LP Notes

In connection with previous transactions whereby Retail Holdings contributed assets to Sunoco LP, Retail Holdings provided a limited contingent guarantee of collection, but not of payment, to Sunoco LP with respect to (i) $800 million principal amount of 6.375% senior notes due 2023 issued by Sunoco LP, (ii) $800 million principal amount of 6.25% senior notes due 2021 issued by Sunoco LP and (iii) $2.035 billion aggregate principal for Sunoco LP's term loan due 2019. In December 2016, Retail Holdings contributed its interests in Sunoco LP, along with the assignment of the guarantee of Sunoco LP's senior notes, to its subsidiary, ETC M-A Acquisition LLC.

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.

FERC Audit

In March 2016, the FERC commenced an audit of Trunkline for the period from January 1, 2013 to present to evaluate Trunkline's compliance with the requirements of its FERC gas tariff, the accounting regulations of the Uniform System of Accounts as prescribed by the FERC, and the FERC's annual reporting requirements. The audit is ongoing.

Commitments

In the normal course of business, ETP purchases, processes and sells natural gas pursuant to long-term contracts and enters into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. ETP believes 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.

ETP's joint venture agreements require that it funds its proportionate share of capital contributions to its unconsolidated affiliates. Such contributions will depend upon ETP's unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. 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,		
	2016	2015	2014
Rental expense[1]	$ 81	$ 176	$ 159
Less: Sublease rental income	(1)	(16)	(26)
Rental expense, net	$ 80	$ 160	$ 133

(1) Includes contingent rentals totaling $26 million and $24 million for the years ended December 31, 2015 and 2014, respectively.

Future minimum lease commitments for such leases are:

Years Ending December 31:	
2017	$ 38
2018	30
2019	28
2020	28
2021	35
Thereafter	133
Future minimum lease commitments	292
Less: Sublease rental income	(14)
Net future minimum lease commitments	$ 278

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.

Dakota Access Pipeline

During the summer of 2016, individuals affiliated with, or sympathetic to, the Standing Rock Sioux Tribe (the “SRST”) began gathering near a construction site on the Dakota Access pipeline project in North Dakota to protest the development of the pipeline project. Some of the protesters eventually trespassed on to the construction site, tampered with equipment, and disrupted construction activity at the site. At this time, we are working with the various authorities to mitigate the effects of this largely unlawful protest. We believe that Dakota Access now has the necessary permits and approvals to perform all work on the pipeline project. In response to the protests, Dakota Access filed a lawsuit in federal court in North Dakota to restrain protestors from disrupting construction and also requested a temporary restraining order (“TRO”) against the Chairman of the SRST and the protestors. The U.S. District Court granted Dakota Access’s request for a TRO, and the defendants filed a motion to dismiss the case and dissolve the TRO. The Court later granted the defendants’ motions to dissolve the TRO. Dakota Access filed a response to the defendant’s motion to dismiss, and the Court has yet to rule. At this time, we cannot determine how long the protest will continue or how the legal action will be resolved. Construction work on the pipeline is ongoing, and, barring legal delays, we expect the final portion of the pipeline to be completed in March or April 2017. Additional protests or legal actions may arise in connection with our Dakota Access project or other projects. Trespass on to construction sites or our physical facilities, or other disruptions, could result in further damage to our assets, safety incidents, potential liability or project delays.

In July 2016, the U.S. Army Corps of Engineers (“USACE”) issued permits to Dakota Access consistent with environmental and historic preservation statutes for the pipeline to make two crossings of the Missouri River in North Dakota, including a crossing of the Missouri River at Lake Oahe. The USACE has also issued an easement to allow the pipeline to cross land owned by the USACE adjacent to the Missouri River in two locations. The SRST filed a lawsuit in the U.S. District Court for the District of Columbia against the USACE challenging the legality of the permits issued for the construction of the Dakota Access pipeline across those waterways and claiming violations of the National Historic Preservation Act (“NHPA”). The SRST also sought a preliminary injunction to rescind the USACE permits while the case is pending. Dakota Access’ moved to intervene in the case and that motion was granted by the Court. The SRST has also sought an emergency TRO to stop construction on the pipeline project. On September 9, 2016, the Court denied SRST’s motion for a preliminary injunction. After that decision, the Department of the Army, the Department of Justice, and the Department of the Interior released a joint statement stating that the USACE would not grant the easement for the land adjacent to Lake Oahe until the federal departments completed a review of the SRST’s claims in its lawsuit with respect to the USACE’s compliance with certain federal statutes in connection with its activities related to the granting of the permits. The SRST appealed the denial of the preliminary injunction to the U.S. Court of Appeals for the D.C. Circuit and filed an emergency motion for an injunction pending the appeal to the U.S. District Court. The U.S. District Court denied SRST’s emergency motion for an injunction pending the appeal. The SRST filed an amended complaint and added claims based on treaties between the tribes and the United States and statues governing the use of government property. The D.C. Circuit denied the SRST’s application for a stay pending appeal and later dismissed the SRST’s appeal of the denied TRO.

In December 2016, the Department of the Army announced that, although its prior actions complied with the law, it intended to conduct further environmental review of the crossing at Lake Oahe. In January 2017, pursuant to a presidential memorandum, the Department of the Army decided that no further environmental review was necessary and delivered Dakota Access an easement to cross Lake Oahe. Construction at the site is ongoing. In the fall of 2016, the Cheyenne River Sioux Tribe intervened alongside the SRST. After USACE gave Dakota Access its final easement, the Cheyenne River Sioux moved for a preliminary injunction and TRO blocking construction. These motions raised, for the first time, claims based on the religious rights of the tribe. The district court denied the TRO and has yet to decide whether to grant a preliminary injunction. The SRST has also moved for summary judgment on its claims against the government based on its treaty rights and the National Environmental Policy Act, and the district court is still considering this motion. Briefing is ongoing.

In addition, the Oglala and Yankton Sioux tribes have filed related lawsuits in an effort to prevent construction of the Dakota Access pipeline project.

While we believe that the pending lawsuits are unlikely to block construction or operation of the pipeline and that construction on the land adjacent to Lake Oahe will be completed in a timely manner, we cannot assure this outcome. Any significant delay imposed by the court will delay the receipt of revenue from this project. We cannot determine when or how these lawsuits will be resolved or the impact they may have on the Dakota Access project.

Mont Belvieu Incident

On June 26, 2016, a hydrocarbon storage well located on another operator’s facility adjacent to Lone Star NGL Mont Belvieu’s (Lone Star) facilities in Mont Belvieu, Texas experienced an over-pressurization resulting in a subsurface release. The subsurface release caused a fire at Lone Star’s South Terminal (CMB) and damage to Lone Star’s storage well operations at its South and North Terminals. Normal operations have resumed at the facilities with the exception of one of Lone Star’s storage wells. The extent of possible damages is still under investigation.

MTBE Litigation

Sunoco, Inc. and/or Sunoco, Inc. (R&M), along with other refiners, manufacturers and sellers of gasoline, are defendants 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 primarily assert 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 seek to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages and attorneys’ fees.

As of December 31, 2016, Sunoco, Inc. is a defendant in six cases, including cases initiated by the States of New Jersey, Vermont, Pennsylvania, Rhode Island, 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. The initial set of 19 New Jersey trial sites are now pending before the United States District Judge for the District of New Jersey, the Hon. Freda L. Wolfson for the pre-trial and trial phases. Judge Wolfson then referred the case to United States Magistrate Judge for the District of New Jersey, the Hon. Lois H. Goodman. Judge Goodman conducted a status conference with all of the parties and inquired whether the parties will engage in a global mediation and instructed the parties to exchange possible mediator names. All parties agreed to participate in global settlement discussions in a global mediation forum before Hon. Garrett Brown (Ret.), a Judicial Arbitration Mediation Service mediator. The remaining portion of the New Jersey case remains in the multidistrict litigation. The first mediation session with Judge Brown is scheduled for November 2 through November 3, 2016. In early 2017, Sunoco, Inc. and two other co-defendants reached a settlement in principle with the State of New Jersey, subject to the parties agreeing on the terms and conditions of a Settlement and Release agreement. It is reasonably possible that a loss may be realized in the remaining cases; 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.

Regency Merger Litigation

Following the January 26, 2015 announcement of the Regency Merger, purported Regency unitholders filed lawsuits in state and federal courts in Dallas and Delaware asserting claims relating to the Regency Merger. All Regency Merger-related lawsuits have been dismissed, although one lawsuit remains pending on appeal. On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint on behalf of Regency's common unitholders in the Court of Chancery of the State of Delaware. The lawsuit alleges that the Regency Merger breached the Regency partnership agreement because Regency's conflicts committee was not properly formed, and the Regency Merger was not approved in good faith. Defendants filed a motion to dismiss, and on March 29, 2016, the Delaware court granted Defendants' motion and dismissed the lawsuit. On April 26, 2016, Dieckman filed his Notice of Appeal to the Supreme Court of Delaware. This appeal is styled Adrian Dieckman v. Regency GP LP, et al., No. 208, 2016, in the Supreme Court of the State of Delaware. Dieckman filed his Opening Brief on June 9, 2016, and Defendants' filed their Answering Brief on July 29, 2016. On August 31, 2016, Dieckman filed his Reply Brief. Oral argument was held on November 16, 2016 before the Delaware Supreme Court. On January 20, 2017, The Delaware Supreme Court issued an order reversing the judgment of the Court of Chancery that dismissed Counts I and II of Dieckman's Complaint.

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 with the Texas Court of Appeals, and briefing by Enterprise and ETP is complete. Oral argument was held on April 20, 2016. The Court of Appeals is taking the briefs under advisement. 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.

Sunoco Logistics Merger Litigation

Between January 6, 2017 and February 8, 2017, seven purported ETP common unitholders ("Plaintiffs") separately filed seven putative unitholder class action lawsuits challenging the merger and the disclosures made in connection with the merger. The lawsuits are styled (a) *Koma v. Energy Transfer Partners, L.P., et al.*, Case No. 3:17-cv-00060-G, in the United States District Court for the Northern District of Texas, Dallas Division (the "*Koma* Lawsuit"); (b) *Ashraf v. Energy Transfer Partners, L.P. et al.*, Case No. 3:17-cv-00118-B, in the United States District Court for the Northern District of Texas, Dallas Division (the "*Ashraf* Lawsuit"); (c) *Shure v. Energy Transfer Partners, L.P. et al.*, Case No. 1:17-cv-00044-UNA, in the United States District Court for the District of Delaware (the "*Shure* Lawsuit"); (d) *Verlin v. Energy Transfer Partners, L.P. et al.*, Case No. 1:17-cv-00045-UNA, in the United States District Court for the District of Delaware (the "*Verlin* Lawsuit"); (e) *Duany v. Energy Transfer Partners, L.P. et al.*, Case No. 1:17-cv-00058-UNA, in the United States District Court for the District of Delaware (the "*Duany* Lawsuit"); (f) *Epstein v. Energy Transfer Partners, L.P. et. al.*, Case No, 1:17-cv-00069, in the United

States District Court for the District of Delaware (the "*Epstein* Lawsuit") and (g) *Sgnilek v. Energy Transfer Partners, L.P. et al.*, Case No. 1:17-cv-00141, in the United States District Court for the District of Delaware (the "*Sgnilek* Lawsuit" and collectively with the *Koma* Lawsuit, *Ashraf* Lawsuit, *Shure* Lawsuit, *Verlin* Lawsuit, *Duany* Lawsuit, and *Epstein* Lawsuit, the "Lawsuits"). The *Koma* Lawsuit, *Ashraf* Lawsuit, *Duany* Lawsuit, and *Epstein* Lawsuit are filed against ETP, ETP GP, ETP GP, LLC, ETE, and the members of the ETP Board. The *Shure* Lawsuit and *Verlin* Lawsuit are filed against ETP, ETP GP, the members of the ETP Board, ETE, Sunoco Logistics, and Sunoco Logistics GP. The *Sgnilek* Lawsuit is filed against ETP, ETP GP, ETP GP LLC, ETE, the members of the ETP Board, Sunoco Logistics and Sunoco Logistics GP (collectively "Defendants").

Plaintiffs allege causes of action challenging the merger and the preliminary joint proxy statement/prospectus filed in connection with the merger. According to Plaintiffs, the preliminary joint proxy statement/prospectus is allegedly misleading because, among other things, it fails to disclose certain information concerning, in general, (a) the background and process that led to the merger; (b) ETE's, ETP's, and Sunoco Logistics' financial projections; (c) the financial analysis and fairness opinion provided by Barclays; and (d) alleged conflicts of interest concerning Barclays, ETE, and certain officers and directors of ETP and ETE. Based on these allegations, and in general, Plaintiffs allege that (i) Defendants have violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and (ii) the members of the ETP Board have violated Section 20(a) of the Exchange Act. Plaintiffs in the Shure Lawsuit and Verlin Lawsuit also allege that Sunoco Logistics has violated Section 20(a) of the Exchange Act. Plaintiffs also assert, in general, that the terms of the merger (including, among other terms, the merger consideration) are unfair to ETP common unitholders and resulted from an unfair and conflicted process. Based on these allegations, the *Sgnilek* Lawsuit alleges that (a) the ETP Board, ETP GP, ETP GP LLC, ETP, and ETE have breached the covenant of good faith and/or fiduciary duties, and (b) Sunoco Logistics and Sunoco Logistics GP have aided and abetted those alleged breaches.

Based on these allegations, Plaintiffs seek to enjoin Defendants from proceeding with or consummating the merger unless and until Defendants disclose the allegedly omitted information summarized above. The *Koma* Lawsuit and *Sgnilek* Lawsuit also seek to enjoin Defendants from proceeding with or consummating the merger unless and until the ETP Board adopts and implements processes to obtain the best possible terms for ETP common unitholders. To the extent that the merger is consummated before injunctive relief is granted, Plaintiffs seek to have the merger rescinded. Plaintiffs also seek damages and attorneys' fees.

Defendants' dates to answer, move to dismiss, or otherwise respond to the Lawsuits have not yet been set. Defendants cannot predict the outcome of these or any other lawsuits that might be filed subsequent to the date of the filing of this annual report, nor can Defendants predict the amount of time and expense that will be required to resolve such litigation. Defendants believe the Lawsuits are without merit and intend to defend vigorously against the Lawsuits and any other actions challenging the merger.

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, 2016 and 2015, accruals of approximately $53 million and $40 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome. 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, 2016 or 2015 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Compliance Orders from the New Mexico Environmental Department

Regency received a Notice of Violation from the New Mexico Environmental Department on September 23, 2015 for allegations of violations of New Mexico air regulations related to Jal #3. The Partnership has accrued $250,000 related to the claims and will continue to assess its potential exposure to the allegations as the matter progresses. The Air Quality Bureau issued a Settlement Offer for Revised Notice of Violation REG-0569-1402-RI on February 7, 2017. The Settlement Agreement includes a civil penalty of $465,000. Energy Transfer and the New Mexico Environmental Department are scheduling a meeting to discuss the Settlement Offer in March 2017.

Lone Star NGL Fractionators Notice of Enforcement

Lone Star NGL Fractionators received a Notice of Enforcement from the Texas Commission on Environmental Quality on August 28, 2015 for allegations of violations of Texas air regulations related to Mont Belvieu Gas Plant. The Partnership has accrued $50,000 related to this claim as of December 31, 2016 and will continue to assess its potential exposure to the allegations as the matter progresses. As of December 31, 2016, the Agreed Order is in the approval process with the Texas Commission on Environmental Quality and includes a $21,000 Supplemental Environmental Project.

Environmental Matters

Our operations are subject to extensive federal, tribal, 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. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations but there can be no assurance that such costs will not be material in the future or that such future compliance with existing, amended or new legal requirements will not have a material adverse effect on our business and operating results. 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 investigatory, remedial and corrective action obligations, the issuance of injunctions in affected areas 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, including 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, 2016, Sunoco, Inc. had been named as a PRP at approximately 50 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,	
	2016	2015
Current	$ 32	$ 41
Non-current	313	326
Total environmental liabilities	$ 345	$ 367

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, 2016 and 2015, the Partnership recorded $43 million and $38 million, respectively, of expenditures related to environmental cleanup programs.

On December 2, 2010, Sunoco, Inc. entered an Asset Sale and Purchase Agreement to sell the Toledo Refinery to Toledo Refining Company LLC (“TRC”) wherein Sunoco, Inc. retained certain liabilities associated with the pre-Closing time period. On January 2, 2013, USEPA issued a Finding of Violation (“FOV”) to TRC and, on September 30, 2013, EPA issued an NOV/ FOV to TRC alleging Clean Air Act violations. To date, EPA has not issued an FOV or NOV/FOV to Sunoco, Inc. directly but some of EPA’s claims relate to the time period that Sunoco, Inc. operated the refinery. Specifically, EPA has claimed that the refinery flares were not operated in a manner consistent with good air pollution control practice for minimizing emissions and/or in conformance with their design, and that Sunoco, Inc. submitted semi-annual compliance reports in 2010 and 2011 and EPA that failed to include all of the information required by the regulations. EPA has proposed penalties in excess of $200,000 to resolve the allegations and discussions continue between the parties. The timing or outcome of this matter cannot be reasonably determined at this time, however, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

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.

In January 2012, Sunoco Logistics experienced a release on its products pipeline in Wellington, Ohio. In connection with this release, the PHMSA issued a Corrective Action Order under which Sunoco Logistics is obligated to follow specific requirements in the investigation of the release and the repair and reactivation of the pipeline. Sunoco Logistics also entered into an Order on Consent with the EPA regarding the environmental remediation of the release site. All requirements of the Order on Consent with the EPA have been fulfilled and the Order has been satisfied and closed. Sunoco Logistics has also received a "No Further Action" approval from the Ohio EPA for all soil and groundwater remediation requirements. In May 2016, Sunoco Logistics received a proposed penalty from the EPA and U.S. Department of Justice associated with this release, and continues to work with the involved parties to bring this matter to closure. The timing and outcome of this matter cannot be reasonably determined at this time. However, Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

In 2012, the EPA issued a proposed consent agreement related to the releases that occurred at Sunoco Logistics’ pump station/tank farm in Barbers Hill, Texas and pump station/tank farm located in Cromwell, Oklahoma in 2010 and 2011, respectively. These matters were referred to the DOJ by the EPA. In November 2012, Sunoco Logistics received an initial assessment of $1.4 million associated with these releases. Sunoco Logistics is in discussions with the EPA and the DOJ on this matter to resolve the issue. The timing or outcome of this matter cannot be reasonably determined at this time. Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

In April 2015 and October 2016, the PHMSA issued separate Notices of Probable Violation ("NOPVs") and a Proposed Compliance Order ("PCO") related to Sunoco Logistics’ West Texas Gulf pipeline in connection with repairs being carried out on the pipeline and other administrative and procedural findings. The proposed penalties are in excess of $100,000. Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

In April 2016, the PHMSA issued a NOPV, PCO and Proposed Civil Penalty related to certain procedures carried out during construction of Sunoco Logistics’ Permian Express 2 pipeline system in Texas. The proposed penalties are in excess of $100,000. Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

In June 2016, the PHMSA issued NOPVs and a PCO in connection with alleged violations on Sunoco Logistics’ Texas crude oil pipeline system. The proposed penalties are in excess of $100,000. Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows or financial position.

In July 2016, the PHMSA issued a NOPV and PCO in connection with inspection and maintenance activities related to a 2013 incident on Sunoco Logistics' crude oil pipeline near Wortham, Texas. The proposed penalties are in excess of $100,000, and Sunoco Logistics is currently in discussions with PHMSA to resolve these matters. The timing or outcome of these matters cannot be reasonably determined at this time, however, Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows, or financial position.

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 past costs for OSHA required activities, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances have not had a material adverse effect on our results of operations but there is no assurance that such costs will not be material in the future.

12. DERIVATIVE ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of commodity prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in our consolidated balance sheets.

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. At hedge inception, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract. Changes in the spreads between the forward natural gas prices 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.

We use futures, swaps and options to hedge the sales price of natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation and storage segment. These contracts are not designated as hedges for accounting purposes.

We use NGL and crude derivative swap contracts to hedge forecasted sales of NGL and condensate equity volumes we retain for fees in our midstream segment whereby our subsidiaries generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price for the residue gas and NGL. These contracts are not designated as hedges for accounting purposes.

We use derivatives in our NGL and refined products transportation and services segment to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

Sunoco Logistics utilizes swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs. These contracts are not designated as hedges for accounting purposes.

We use financial commodity derivatives to take advantage of market opportunities in our trading activities which complement our transportation and storage segment's operations and are netted in cost of products sold in our consolidated statements of operations. We also have trading and marketing activities related to power and natural gas in our all other segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

The following table details our outstanding commodity-related derivatives:

	December 31, 2016		December 31, 2015	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	(682,500)	2017	(602,500)	2016-2017
Basis Swaps IFERC/NYMEX[1]	2,242,500	2017	(31,240,000)	2016-2017
Power (Megawatt):				
Forwards	391,880	2017-2018	357,092	2016-2017
Futures	109,564	2017-2018	(109,791)	2016
Options – Puts	(50,400)	2017	260,534	2016
Options – Calls	186,400	2017	1,300,647	2016
Crude (Bbls) – Futures	(617,000)	2017	(591,000)	2016-2017
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	10,750,000	2017-2018	(6,522,500)	2016-2017
Swing Swaps IFERC	(5,662,500)	2017	71,340,000	2016-2017
Fixed Swaps/Futures	(52,652,500)	2017-2019	(14,380,000)	2016-2018
Forward Physical Contracts	(22,492,489)	2017	21,922,484	2016-2017
Natural Gas Liquid (Bbls) – Forwards/Swaps	(5,786,627)	2017	(8,146,800)	2016-2018
Refined Products (Bbls) – Futures	(2,240,000)	2017	(939,000)	2016-2017
Corn (Bushels) – Futures	—	—	1,185,000	2016
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(36,370,000)	2017	(37,555,000)	2016
Fixed Swaps/Futures	(36,370,000)	2017	(37,555,000)	2016
Hedged Item – Inventory	36,370,000	2017	37,555,000	2016

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

Interest Rate Risk

We are exposed to market risk for changes in interest rates. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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

		Notional Amount Outstanding	
Term	Type[1]	December 31, 2016	December 31, 2015
July 2016[2]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	$ —	$ 200
July 2017[3]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	500	300
July 2018[3]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
July 2019[3]	Forward-starting to pay a fixed rate of 3.25% and receive a floating rate	200	200
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300

(1) Floating rates are based on 3-month LIBOR.

(2) 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.

(3) Represents the effective date. These forward-starting swaps have terms 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 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. The Partnership also uses industry standard commercial agreements which allow for the netting of 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, midstream companies and independent power generators. 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.

The Partnership 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 our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

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

Derivative Summary

The following table provides a summary of our derivative assets and liabilities:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2016	December 31, 2015	December 31, 2016	December 31, 2015
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ —	$ 38	$ (4)	$ (3)
	—	38	(4)	(3)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	338	353	(416)	(306)
Commodity derivatives	24	57	(52)	(41)
Interest rate derivatives	—	—	(193)	(171)
Embedded derivatives in ETP Preferred Units	—	—	(1)	(5)
	362	410	(662)	(523)
Total derivatives	$ 362	$ 448	$ (666)	$ (526)

The following table presents the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset on the consolidated balance sheets that are subject to enforceable master netting arrangements or similar arrangements:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2016	December 31, 2015	December 31, 2016	December 31, 2015
Derivatives without offsetting agreements	Derivative assets (liabilities)	$ —	$ —	$ (194)	$ (176)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	24	57	(52)	(41)
Broker cleared derivative contracts	Other current assets	338	391	(420)	(309)
		362	448	(666)	(526)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(4)	(17)	4	17
Payments on margin deposit	Other current assets	(338)	(309)	338	309
Total net derivatives		$ 20	$ 122	$ (324)	$ (200)

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:

	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,		
		2016	2015	2014
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$ —	$ —	$ (3)
Total		$ —	$ —	$ (3)

	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,		
		2016	2015	2014
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ 14	$ 21	$ (8)
Total		$ 14	$ 21	$ (8)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2016	2015	2014
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$ (35)	$ (11)	$ (6)
Commodity derivatives – Non-trading	Cost of products sold	(173)	23	199
Interest rate derivatives	Losses on interest rate derivatives	(12)	(18)	(157)
Embedded derivatives	Other, net	4	12	3
Total		$ (216)	$ 6	$ 39

13. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all eligible employees. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries made matching contributions of $44 million, $39 million and $50 million to these 401(k) savings plans for the years ended December 31, 2016, 2015, and 2014, respectively.

Pension and Other Postretirement Benefit Plans

Panhandle

Postretirement benefits expense for the years ended December 31, 2016 and 2015 reflect the impact of changes Panhandle or its affiliates adopted as of September 30, 2013, to modify its retiree medical benefits program, effective January 1, 2014. The modification placed all eligible retirees on a common medical benefit platform, subject to limits on Panhandle's annual contribution toward eligible retirees' medical premiums. Prior to January 1, 2013, affiliates of Panhandle offered postretirement health care and life insurance benefit plans (other postretirement plans) that covered substantially all employees. Effective January 1, 2013, participation in the plan was frozen and medical benefits were no longer offered to non-union employees. Effective January 1, 2014, retiree medical benefits were no longer offered to union employees.

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 paid lump sums to eligible active and terminated vested participants in December 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, 2016			December 31, 2015		
	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	$ 20	$ 57	$ 180	$ 718	$ 65	$ 202
Interest cost	1	2	4	23	2	4
Benefits paid, net	(1)	(7)	(21)	(46)	(8)	(20)
Actuarial (gain) loss and other	(2)	(1)	2	16	(2)	(6)
Settlements	—	—	—	(691)	—	—
Benefit obligation at end of period	18	51	165	20	57	180
Change in plan assets:						
Fair value of plan assets at beginning of period	15	—	253	598	—	265
Return on plan assets and other	(2)	—	6	16	—	—
Employer contributions	—	—	10	138	—	8
Benefits paid, net	(1)	—	(21)	(46)	—	(20)
Settlements	—	—	—	(691)	—	—
Fair value of plan assets at end of period	12	—	248	15	—	253
Amount underfunded (overfunded) at end of period	$ 6	$ 51	$ (83)	$ 5	$ 57	$ (73)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$ —	$ —	$ 108	$ —	$ —	$ 97
Current liabilities	—	(7)	(2)	—	(9)	(2)
Non-current liabilities	(6)	(44)	(23)	(5)	(48)	(22)
	$ (6)	$ (51)	$ 83	$ (5)	$ (57)	$ 73
Amounts recognized in accumulated other comprehensive income (loss) (pre-tax basis) consist of:						
Net actuarial gain	$ —	$ —	$ (12)	$ 2	$ 4	$ (17)
Prior service cost	—	—	14	—	—	15
	$ —	$ —	$ 2	$ 2	$ 4	$ (2)

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

	December 31, 2016			December 31, 2015		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$ 18	$ 51	N/A	$ 20	$ 57	N/A
Accumulated benefit obligation	18	51	$ 165	20	57	$ 180
Fair value of plan assets	12	—	248	15	—	253

Components of Net Periodic Benefit Cost

	December 31, 2016		December 31, 2015	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Interest cost	$ 3	$ 4	$ 25	$ 4
Expected return on plan assets	(1)	(8)	(16)	(8)
Prior service cost amortization	—	1	—	1
Settlements	—	—	32	—
Net periodic benefit cost	$ 2	$ (3)	$ 41	$ (3)

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2016		December 31, 2015	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.65%	2.34%	3.59%	2.38%
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, 2016		December 31, 2015	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.60%	3.06%	3.65%	2.79%
Expected return on assets:				
Tax exempt accounts	3.50%	7.00%	7.50%	7.00%
Taxable accounts	N/A	4.50%	N/A	4.50%
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 and Sunoco, Inc.'s other postretirement benefit plans are shown in the table below:

	December 31,	
	2016	2015
Health care cost trend rate	6.73%	7.16%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.96%	5.39%
Year that the rate reaches the ultimate trend rate	2021	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 Measurements at December 31, 2016		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Mutual funds[(1)]	$ 12	$ 12	$ —	$ —
Total	$ 12	$ 12	$ —	$ —

(1) Comprised of approximately 100% equities as of December 31, 2016.

		Fair Value Measurements at December 31, 2015		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Mutual funds[(1)]	$ 15	$ —	$ 15	$ —
Total	$ 15	$ —	$ 15	$ —

(1) Comprised of approximately 100% equities as of December 31, 2015.

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

		Fair Value Measurements at December 31, 2016		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 23	$ 23	$ —	$ —
Mutual funds[1]	134	134	—	—
Fixed income securities	91	—	91	—
Total	$ 248	$ 157	$ 91	$ —

(1) Primarily comprised of approximately 31% equities, 66% fixed income securities and 3% cash as of December 31, 2016.

		Fair Value Measurements at December 31, 2015		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 18	$ 18	$ —	$ —
Mutual funds[1]	133	133	—	—
Fixed income securities	102	—	102	—
Total	$ 253	$ 151	$ 102	$ —

(1) Primarily comprised of approximately 56% equities, 33% fixed income securities and 11% cash as of December 31, 2015.

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.

Contributions

We expect to contribute $12 million to pension plans and $10 million to other postretirement plans in 2017. 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 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)
2017	$ 1	$ 7	$ 26
2018	1	7	25
2019	1	6	23
2020	1	6	22
2021	1	5	19
2022 – 2026	6	17	39

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.

14. RELATED PARTY TRANSACTIONS:

ETE has agreements with subsidiaries to provide or receive various general and administrative services. ETE pays us to provide services on its behalf and on behalf of other subsidiaries of ETE, which includes the reimbursement of various operating and general and administrative expenses incurred by us on behalf of ETE and its subsidiaries.

In January 2016, ETE and ETP agreed to extend the $95 million annual management fee paid to ETP through 2016.

The Partnership also has related party transactions with several of its equity method investees. In addition to commercial transactions, these transactions include the provision of certain management services and leases of certain assets.

The following table summarizes the affiliate revenues on our consolidated statements of operations:

	Years Ended December 31,		
	2016	2015	2014
Affiliated revenues	$ 377	$ 417	$ 965

The following table summarizes the related company balances on our consolidated balance sheets:

	December 31,	
	2016	2015
Accounts receivable from related companies:		
ETE	$ 22	$ 110
Sunoco LP	96	3
PES	6	10
FGT	15	13
Lake Charles LNG	4	36
Trans-Pecos Pipeline, LLC	1	29
Comanche Trail Pipeline, LLC	—	22
Other	65	45
Total accounts receivable from related companies	$ 209	$ 268
Accounts payable to related companies:		
ETE	$ —	$ 1
Sunoco LP	20	5
FGT	1	1
Lake Charles LNG	3	3
Other	19	15
Total accounts payable to related companies	$ 43	$ 25

	December 31,	
	2016	2015
Long-term notes receivable (payable) – related companies:		
Sunoco LP	$ 87	$ (233)
Phillips 66	(250)	—
Net long-term notes receivable (payable) – related companies	$ (163)	$ (233)

15. REPORTABLE SEGMENTS:

Our financial statements currently reflect the following reportable segments, which conduct their business in the United States, as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;
- crude oil transportation and services; and
- all other.

The Partnership previously presented its retail marketing business as a separate reportable segment. Due to the transfer of the general partner interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016, all of the Partnership's retail marketing business has been deconsolidated. The only remaining retail marketing assets are the limited partner units of Sunoco LP. As of December 31, 2016, the Partnership's interest in Sunoco LP common units consisted of 43.5 million units, representing 44.3% of Sunoco LP's total outstanding common units. This equity method investment in Sunoco LP has now been aggregated into the all other segment. Consequently, the retail marketing business that was previously consolidated has also been aggregated in the all other segment for all periods presented.

Intersegment and intrasegment transactions are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation and storage segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL and refined products transportation and services segment are primarily reflected in NGL sales and gathering, transportation, terminalling and other fees. Revenues from our crude oil transportation and services segment are primarily reflected in crude sales. Revenues from our all other segment are primarily reflected in refined product sales.

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, 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, losses on extinguishments of debt 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.

The following tables present financial information by segment:

	Years Ended December 31,		
	2016	2015	2014
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$ 2,155	$ 1,912	$ 2,645
Intersegment revenues	458	338	212
	2,613	2,250	2,857
Interstate transportation and storage:			
Revenues from external customers	946	1,008	1,057
Intersegment revenues	23	17	15
	969	1,025	1,072
Midstream:			
Revenues from external customers	2,342	2,607	4,770
Intersegment revenues	2,837	2,449	2,053
	5,179	5,056	6,823
NGL and refined products transportation and services:			
Revenues from external customers	5,973	4,569	4,746
Intersegment revenues	562	549	379
	6,535	5,118	5,125
Crude oil transportation and services:			
Revenues from external customers	7,539	8,980	16,904
Intersegment revenues	357	287	278
	7,896	9,267	17,182
All other:			
Revenues from external customers	2,872	15,216	25,353
Intersegment revenues	400	558	465
	3,272	15,774	25,818
Eliminations	(4,637)	(4,198)	(3,402)
Total revenues	$ 21,827	$ 34,292	$ 55,475

	Years Ended December 31,		
	2016	2015	2014
Cost of products sold:			
Intrastate transportation and storage	$ 1,897	$ 1,554	$ 2,169
Midstream	3,381	3,264	4,893
NGL and refined products transportation and services	4,591	3,458	3,855
Crude oil transportation and services	6,740	8,446	16,446
All other	2,942	14,029	24,129
Eliminations	(4,157)	(3,722)	(3,078)
Total cost of products sold	$ 15,394	$ 27,029	$ 48,414

	Years Ended December 31,		
	2016	2015	2014
Depreciation, depletion and amortization:			
Intrastate transportation and storage	$ 144	$ 129	$ 125
Interstate transportation and storage	207	210	203
Midstream	840	720	568
NGL and refined products transportation and services	355	290	218
Crude oil transportation and services	251	218	192
All other	189	362	363
Total depreciation, depletion and amortization	$ 1,986	$ 1,929	$ 1,669

	Years Ended December 31,		
	2016	2015	2014
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ 35	$ 32	$ 27
Interstate transportation and storage	193	197	196
Midstream	19	(19)	10
NGL and refined products transportation and services	41	29	20
Crude oil transportation and services	(4)	(9)	—
All other	(225)	239	79
Total equity in earnings of unconsolidated affiliates	$ 59	$ 469	$ 332

	Years Ended December 31,		
	2016	2015	2014
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 613	$ 543	$ 559
Interstate transportation and storage	1,117	1,155	1,212
Midstream	1,133	1,237	1,318
NGL and refined products transportation and services	1,483	1,225	891
Crude oil transportation and services	719	671	671
All other	540	883	1,059
Total Segment Adjusted EBITDA	5,605	5,714	5,710
Depreciation, depletion and amortization	(1,986)	(1,929)	(1,669)
Interest expense, net	(1,317)	(1,291)	(1,165)
Gains on acquisitions	83	—	—
Gain on sale of AmeriGas common units	—	—	177
Impairment losses	(813)	(339)	(370)
Losses on interest rate derivatives	(12)	(18)	(157)
Non-cash unit-based compensation expense	(80)	(79)	(68)
Unrealized gains (losses) on commodity risk management activities	(131)	(65)	112
Inventory valuation adjustments	170	(104)	(473)
Losses on extinguishments of debt	—	(43)	(25)
Adjusted EBITDA related to discontinued operations	—	—	(27)
Adjusted EBITDA related to unconsolidated affiliates	(946)	(937)	(748)
Equity in earnings from unconsolidated affiliates	59	469	332
Impairment of investment in an unconsolidated affiliate	(308)	—	—
Other, net	114	20	(36)
Income from continuing operations before income tax expense (benefit)	$ 438	$ 1,398	$ 1,593

	December 31,		
	2016	2015	2014
Assets:			
Intrastate transportation and storage	$ 5,164	$ 4,882	$ 4,983
Interstate transportation and storage	10,833	11,345	10,779
Midstream	17,873	17,039	15,534
NGL and refined products transportation and services	14,128	11,613	9,387
Crude oil transportation and services	15,941	10,941	8,645
All other	6,252	9,353	13,190
Total assets	$ 70,191	$ 65,173	$ 62,518

	Years Ended December 31,		
	2016	2015	2014
Additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (accrual basis):			
Intrastate transportation and storage	$ 76	$ 105	$ 169
Interstate transportation and storage	280	860	411
Midstream	1,255	2,172	1,298
NGL and refined products transportation and services	2,198	2,710	2,044
Crude oil transportation and services	2,014	2,084	928
All other	160	729	611
Total additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (accrual basis)	$ 5,983	$ 8,660	$ 5,461

	December 31,		
	2016	2015	2014
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$ 387	$ 406	$ 423
Interstate transportation and storage	2,149	2,516	2,649
Midstream	111	117	138
NGL and refined products transportation and services	235	258	240
Crude oil transportation and services	18	21	17
All other	1,380	1,685	293
Total advances to and investments in unconsolidated affiliates	$ 4,280	$ 5,003	$ 3,760

16. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners and variations in the weighted average units outstanding used in computing such amounts.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2016:					
Revenues	$ 4,481	$ 5,289	$ 5,531	$ 6,526	$ 21,827
Operating income (loss)	614	715	638	(165)	1,802
Net income (loss)	376	472	138	(362)	624
Common Unitholders' interest in net income (loss)	(67)	60	(241)	(762)	(1,010)
Basic net income (loss) per Common Unit	$ (0.10)	$ 0.07	$ (0.33)	$ (0.98)	$ (1.37)
Diluted net income (loss) per Common Unit	$ (0.10)	$ 0.07	$ (0.33)	$ (0.98)	$ (1.37)

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2015:					
Revenues	$ 10,326	$ 11,540	$ 6,601	$ 5,825	$ 34,292
Operating income	608	888	576	187	2,259
Net income	268	839	393	21	1,521
Common Unitholders’ interest in net income (loss)	(48)	298	59	(327)	(18)
Basic net income (loss) per Common Unit	$ (0.11)	$ 0.45	$ 0.07	$ (0.45)	$ (0.06)
Diluted net income (loss) per Common Unit	$ (0.11)	$ 0.45	$ 0.07	$ (0.45)	$ (0.07)

The three months ended December 31, 2016 and 2015 reflected the unfavorable impacts of $27 million and $120 million, respectively, related to non-cash inventory valuation adjustments. The three months ended December 31, 2016 and 2015 reflected the recognition of impairment losses of $813 million and $339 million, respectively. Impairment losses in 2016 were primarily related to our PEPL reporting unit, Sea Robin reporting unit and midstream midcontinent operations. In 2015, impairment losses were primarily related to Lone Star Refinery Services operations and our Transwestern pipeline. The three months ended September 30, 2016 reflected the recognition of a non-cash impairment of our investment in MEP of $308 million in our interstate transportation and storage segment.

For certain periods reflected above, distributions paid for the period exceeded net income attributable to partners. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.

Table of Contents

17. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

Prior to the Sunoco Logistics Merger, Sunoco Logistics Partners Operations L.P., a subsidiary of Sunoco Logistics was the issuer of multiple series of senior notes that were guaranteed by Sunoco Logistics. Subsequent to the Sunoco Logistics Merger, these notes continue to be guaranteed by the parent company.

These guarantees are full and unconditional. For the purposes of this footnote, Energy Transfer Partners, L.P. is referred to as “Parent Guarantor” and Sunoco Logistics Partners Operations L.P. is referred to as “Subsidiary Issuer.” All other consolidated subsidiaries of the Partnership are collectively referred to as “Non-Guarantor Subsidiaries.”

The following supplemental condensed consolidating financial information reflects the Parent Guarantor’s separate accounts, the Subsidiary Issuer’s separate accounts, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and the Parent Guarantor’s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent Guarantor’s investments in its subsidiaries and the Subsidiary Issuer’s investments in its subsidiaries are accounted for under the equity method of accounting. To present the supplemental condensed consolidating financial information on a comparable basis, the prior period financial information has been recast as if the Sunoco Logistics Merger occurred on January 1, 2014.

The consolidating financial information for the Parent Guarantor, Subsidiary Issuer and Non-Guarantor Subsidiaries are as follows:

	December 31, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ 41	$ 319	$ —	$ 360
All other current assets	—	2	5,367	—	5,369
Property, plant and equipment	—	—	50,917	—	50,917
Investments in unconsolidated affiliates	23,350	10,664	4,280	(34,014)	4,280
All other assets	—	5	9,260	—	9,265
Total assets	$ 23,350	$ 10,712	$ 70,143	$ (34,014)	$ 70,191
Current liabilities	(1,761)	(3,800)	11,764	—	6,203
Non-current liabilities	299	7,313	30,148	(299)	37,461
Noncontrolling interest	—	—	1,297	—	1,297
Total partners' capital	24,812	7,199	26,934	(33,715)	25,230
Total liabilities and equity	$ 23,350	$ 10,712	$ 70,143	$ (34,014)	$ 70,191

	December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ 37	$ 490	$ —	$ 527
All other current assets	—	3	4,168	—	4,171
Property, plant and equipment	—	—	45,087	—	45,087
Investments in unconsolidated affiliates	24,734	9,692	5,003	(34,426)	5,003
All other assets	—	6	10,379	—	10,385
Total assets	$ 24,734	$ 9,738	$ 65,127	$ (34,426)	$ 65,173
Current liabilities	(1,319)	(2,341)	7,781	—	4,121
Non-current liabilities	286	5,591	28,520	(376)	34,021
Noncontrolling interest	—	—	816	—	816
Total partners' capital	25,767	6,488	28,010	(34,050)	26,215
Total liabilities and equity	$ 24,734	$ 9,738	$ 65,127	$ (34,426)	$ 65,173

	Year Ended December 31, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 21,827	$ —	$ 21,827
Operating costs, expenses, and other	—	1	20,024	—	20,025
Operating income (loss)	—	(1)	1,803	—	1,802
Interest expense, net	—	(157)	(1,160)	—	(1,317)
Equity in earnings of unconsolidated affiliates	554	863	59	(1,417)	59
Losses on interest rate derivatives	—	—	(12)	—	(12)
Other, net	—	—	(94)	—	(94)
Income before income tax benefit	554	705	596	(1,417)	438
Income tax benefit	—	—	(186)	—	(186)
Net income	554	705	782	(1,417)	624
Less: Net income attributable to noncontrolling interest	—	—	73	—	73
Net income attributable to partners	$ 554	$ 705	$ 709	$ (1,417)	$ 551
Other comprehensive income	$ —	$ —	$ 4	$ —	$ 4
Comprehensive income	554	705	786	(1,417)	628
Comprehensive income attributable to noncontrolling interest	—	—	73	—	73
Comprehensive income attributable to partners	$ 554	$ 705	$ 713	$ (1,417)	$ 555

	Year Ended December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 34,292	$ —	$ 34,292
Operating costs, expenses, and other	—	1	32,032	—	32,033
Operating income (loss)	—	(1)	2,260	—	2,259
Interest expense, net	—	(133)	(1,158)	—	(1,291)
Equity in earnings of unconsolidated affiliates	1,441	526	469	(1,967)	469
Losses on interest rate derivatives	—	—	(18)	—	(18)
Other, net	—	—	(21)	—	(21)
Income before income tax benefit	1,441	392	1,532	(1,967)	1,398
Income tax benefit	—	—	(123)	—	(123)
Net income	1,441	392	1,655	(1,967)	1,521
Less: Net income attributable to noncontrolling interest	—	—	76	—	76
Net income attributable to partners	$ 1,441	$ 392	$ 1,579	$ (1,967)	$ 1,445
Other comprehensive income	$ —	$ —	$ 60	$ —	$ 60
Comprehensive income	1,441	392	1,715	(1,967)	1,581
Comprehensive income attributable to noncontrolling interest	—	—	76	—	76
Comprehensive income attributable to partners	$ 1,441	$ 392	$ 1,639	$ (1,967)	$ 1,505

	Year Ended December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 55,475	$ —	$ 55,475
Operating costs, expenses, and other	—	—	53,032	—	53,032
Operating income	—	—	2,443	—	2,443
Interest expense, net	—	(62)	(1,103)	—	(1,165)
Equity in earnings of unconsolidated affiliates	1,410	354	332	(1,764)	332
Losses on interest rate derivatives	—	—	(157)	—	(157)
Other, net	—	—	140	—	140
Income from continuing operations before income tax expense	1,410	292	1,655	(1,764)	1,593
Income tax expense from continuing operations	—	—	358	—	358
Income from continuing operations	1,410	292	1,297	(1,764)	1,235
Income from discontinued operations	—	—	64	—	64
Net income	1,410	292	1,361	(1,764)	1,299
Less: Net income attributable to noncontrolling interest	—	—	44	—	44
Less: Net loss attributable to predecessor	—	—	(153)	—	(153)
Net income attributable to partners	$ 1,410	$ 292	$ 1,470	$ (1,764)	$ 1,408
Other comprehensive loss	$ —	$ —	$ (117)	$ —	$ (117)
Comprehensive income	1,410	292	1,244	(1,764)	1,182
Comprehensive income attributable to noncontrolling interest	—	—	44	—	44
Comprehensive income attributable to partners	$ 1,410	$ 292	$ 1,200	$ (1,764)	$ 1,138

	Year Ended December 31, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ 553	$ 675	$ 3,492	$ (1,417)	$ 3,303
Cash flows from investing activities	(976)	(2,400)	(4,431)	1,417	(6,390)
Cash flows from financing activities	423	1,729	768	—	2,920
Change in cash	—	4	(171)	—	(167)
Cash at beginning of period	—	37	490	—	527
Cash at end of period	$ —	$ 41	$ 319	$ —	$ 360

	Year Ended December 31, 2015				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ 1,441	$ 388	$ 2,886	$ (1,968)	$ 2,747
Cash flows from investing activities	(2,271)	(1,815)	(5,702)	1,968	(7,820)
Cash flows from financing activities	830	1,363	2,744	—	4,937
Change in cash	—	(64)	(72)	—	(136)
Cash at beginning of period	—	101	562	—	663
Cash at end of period	$ —	$ 37	$ 490	$ —	$ 527

	Year Ended December 31, 2014				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ 1,410	$ 271	$ 3,252	$ (1,764)	$ 3,169
Cash flows from investing activities	(1,995)	(2,013)	(4,448)	1,764	(6,692)
Cash flows from financing activities	585	1,831	1,202	—	3,618
Change in cash	—	89	6	—	95
Cash at beginning of period	—	12	556	—	568
Cash at end of period	$ —	$ 101	$ 562	$ —	$ 663

Exhibit 99.2

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions, except for ratio amounts)
(Unaudited)

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Fixed Charges:					
Interest expense, net	$ 1,317	$ 1,291	$ 1,165	$ 1,013	$ 788
Capitalized interest	200	163	101	45	101
Interest charges included in rental expense	9	19	17	16	6
Distribution to the Series A Convertible Redeemable Preferred Units	—	3	3	6	8
Accretion of the Series A Convertible Redeemable Preferred Units	—	—	—	—	1
Total fixed charges	1,526	1,476	1,286	1,080	904
Earnings:					
Income from continuing operations before income tax expense and noncontrolling interest	438	1,398	1,593	810	1,817
Less: equity in earnings of unconsolidated affiliates	59	469	332	236	212
Total earnings	379	929	1,261	574	1,605
Add:					
Fixed charges	1,526	1,476	1,286	1,080	904
Amortization of capitalized interest	18	11	8	6	5
Distributed income of equity investees	406	440	291	313	208
Less:					
Interest capitalized	(200)	(163)	(101)	(45)	(101)
Income available for fixed charges	$ 2,129	$ 2,693	$ 2,745	$ 1,928	$ 2,621
Ratio of earnings to fixed charges	1.40	1.82	2.13	1.79	2.90