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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2018
OR

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

Commission file number 1-32740

ENERGY TRANSFER LP

(Exact name of registrant as specified in its charter)

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

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)

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

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

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

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

Yes ☒ No ☐

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

Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes ☒ No ☐

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ 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. ☐

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

Yes ☐ No ☒

The aggregate market value as of June 30, 2018, of the registrant's Common Units held by non-affiliates of the registrant, based on the reported closing price of such Common Units on the New York Stock Exchange on such date, was $13.79 billion. Common Units held by each executive officer and director and by each person who owns 5% or more of the outstanding Common Units have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

At February 15, 2019, the registrant had 2,619,391,387 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

TABLE OF CONTENTS

PART I

		PAGE
ITEM 1.	BUSINESS	1
ITEM 1A.	RISK FACTORS	31
ITEM 1B.	UNRESOLVED STAFF COMMENTS	66
ITEM 2.	PROPERTIES	66
ITEM 3.	LEGAL PROCEEDINGS	67
ITEM 4.	MINE SAFETY DISCLOSURES	70

PART II

ITEM 5.	MARKET FOR REGISTRANT'S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES	71
ITEM 6.	SELECTED FINANCIAL DATA	72
ITEM 7.	MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	73
ITEM 7A.	QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	125
ITEM 8.	FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	127
ITEM 9.	CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE	128
ITEM 9A.	CONTROLS AND PROCEDURES	128
ITEM 9B.	OTHER INFORMATION	130

PART III

ITEM 10.	DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE	131
ITEM 11.	EXECUTIVE COMPENSATION	137
ITEM 12.	SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS	151
ITEM 13.	CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE	153
ITEM 14.	PRINCIPAL ACCOUNTING FEES AND SERVICES	153

PART IV

ITEM 15.	EXHIBITS AND FINANCIAL STATEMENT SCHEDULES	155
ITEM 16	FORM 10-K SUMMARY	156
	Signatures	160

Forward-Looking Statements

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

Definitions

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

/d	per day
Aloha	Aloha Petroleum, Ltd
AOCI	accumulated other comprehensive income (loss)
AROs	asset retirement obligations
Bbls	barrels
BBtu	billion British thermal units
Bcf	billion cubic feet
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy content
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
CDM	CDM Resource Management LLC and CDM Environmental & Technical Services LLC, collectively
Citrus	Citrus, LLC, which owns 100% of FGT
CrossCountry	CrossCountry Energy, LLC
Dakota Access	Dakota Access, LLC
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
EPA	United States 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
ETCO	Energy Transfer Crude Oil Company, LLC
ETO	Energy Transfer Operating, L.P., formerly known as Energy Transfer Partners, L.P.
ETO Series A Preferred Units	Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units

ETO Series B Preferred Units	Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
ETO Series C Preferred Units	Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
ETO Series D Preferred Units	Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETO
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, as amended
ExxonMobil	Exxon Mobil Corporation
FDOT/FTE	Florida Department of Transportation, Florida's Turnpike Enterprise
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC, which owns a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula
GAAP	accounting principles generally accepted in the United States of America
General Partner	LE GP, LLC, the general partner of ET
HPC	RIGS Haynesville Partnership Co. and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	incentive distribution rights
KMI	Kinder Morgan Inc.
Lake Charles LNG	Lake Charles LNG Company, LLC
LCL	Lake Charles LNG Export Company, LLC
LDEQ	Louisiana Department of Environmental Quality
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
LNG Holdings	Lake Charles LNG Holdings, LLC
Lone Star	Lone Star NGL LLC
LPG	liquefied petroleum gas
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
Mid-Valley	Mid-Valley Pipeline Company
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGA	Natural Gas Act of 1938
NGL	natural gas liquid, such as propane, butane and natural gasoline
NGPA	Natural Gas Policy Act of 1978
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
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
PEP	Permian Express Partners LLC
PEPL	Panhandle Eastern Pipe Line Company, LP
PES	Philadelphia Energy Solutions Refining and Marketing LLC
Phillips 66	Phillips 66 Partners LP
PHMSA	Pipeline Hazardous Materials Safety Administration
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings LLC, a subsidiary of ETO
RGS	Regency Gas Services, a wholly-owned subsidiary of Regency
RIGS	Regency Intrastate Gas System
Rover	Rover Pipeline LLC, a subsidiary of ETO
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission
Shell	Royal Dutch Shell plc
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 Partners	Sunoco Partners LLC, the general partner of Sunoco Logistics
TCEQ	Texas Commission on Environmental Quality
Transwestern	Transwestern Pipeline Company, LLC
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle
USAC	USA Compression Partners, LP
USAC Holdings	USA Compression Holdings, LLC
WMB	The Williams Companies, Inc.
WTI	West Texas Intermediate Crude

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, 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

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

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ET" mean Energy Transfer LP and its consolidated subsidiaries, which include ETO, ETP GP, ETP LLC, Panhandle, Sunoco LP, USAC and Lake Charles LNG. References to the "Parent Company" mean Energy Transfer LP on a stand-alone basis.

The primary activities in which we are engaged, all of which are in the United States, and the operating subsidiaries through which we conduct those activities are as follows:

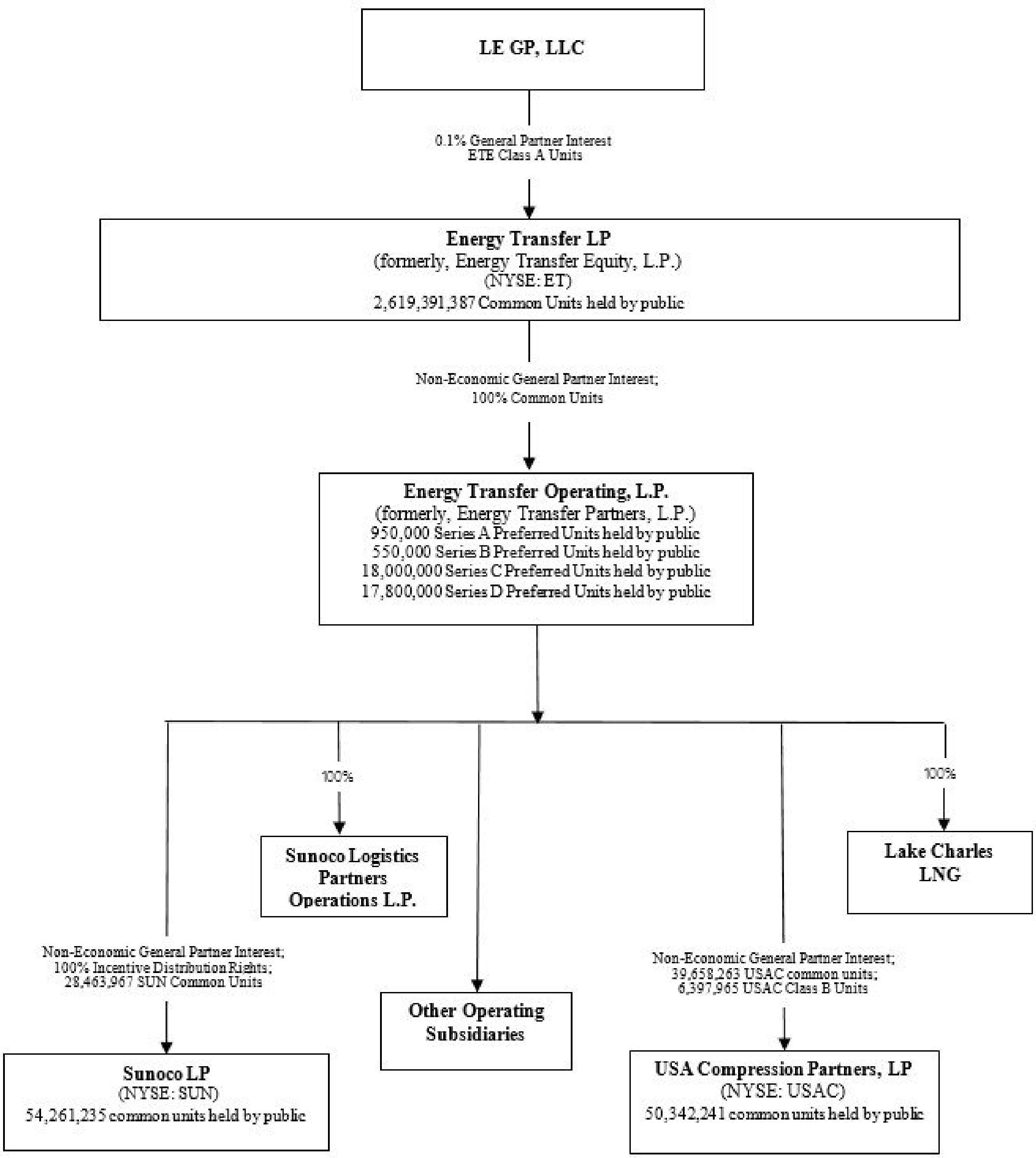
- natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage;
  - interstate natural gas transportation and storage; and
- crude oil, NGL and refined products transportation, terminalling services and acquisition and marketing activities, as well as NGL storage and fractionation services.

In addition, we own investments in other businesses, including Sunoco LP and USAC, both of which are publicly traded master limited partnerships.

Subsequent to the Merger, substantially all of the Partnership's cash flows are derived from distributions related to its investment in ETO, whose cash flows are derived from its subsidiaries, including ETO's investments in Sunoco LP and USAC. The Parent Company's primary cash requirements are for distributions to its partners, general and administrative expenses, debt service requirements and distributions to its partners. The Parent Company-only assets and liabilities are not available to satisfy the debts and other obligations of its subsidiaries. The Parent Company distributes its available cash remaining after satisfaction of the aforementioned cash requirements to its unitholders on a quarterly basis.

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

The following chart summarizes our organizational structure as of February 15, 2019. For simplicity, certain immaterial entities and ownership interests have not been depicted.



Significant Achievements in 2018 and Beyond

Our significant strategic transactions in 2018 and beyond included the following, as discussed in more detail herein:

Significant Transactions

- In October 2018, ET and ETO (previously named Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P., respectively, prior to the October 2018 transactions) completed the merger of ETO with a wholly-owned subsidiary of ET in a unit-for-unit exchange (the “Energy Transfer Merger”). Immediately prior to the Energy Transfer Merger, (i) the IDRs in ETO were converted into ETO Common Units, (ii) the general partner interest in ETO was converted into ETO Common Units, (iii) ET’s interests in Sunoco LP, USAC and their respective general partners were contributed to ETO, and (iv) certain other interests owned by ET were contributed to ETO. The Energy Transfer Merger and these related transactions are discussed further in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

- In April 2018, ETO contributed to USAC all of the issued and outstanding membership interests of CDM for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 USAC common units, (ii) 6,397,965 units of a new class of units representing limited partner interests in USAC ("USAC Class B Units") and (iii) $1.23 billion in cash, including customary closing adjustments (the "CDM Contribution"). The USAC Class B Units have substantially all of the rights and obligations of a USAC common unit, except the USAC Class B Units will not participate in distributions for the first four quarters following the closing date of April 2, 2018. Each USAC Class B Unit will automatically convert into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019. ETO subsequently obtained control of USAC in connection with the transactions related to the Energy Transfer Merger in October 2018, as discussed above.

- ETO previously owned a 49.99% interest in HPC, which owns RIGS. In April 2018, ETO acquired the remaining 50.01% interest in HPC. Prior to April 2018, HPC was reflected as an unconsolidated affiliate in ETO's financial statements; beginning in April 2018, RIGS is reflected as a wholly-owned subsidiary in ETO's financial statements.

- On January 23, 2018, Sunoco LP closed on an asset purchase agreement with 7-Eleven, Inc., a Texas corporation ("7-Eleven"), and SEI Fuel Services, Inc., a Texas corporation and wholly-owned subsidiary of 7-Eleven. Under the agreement, Sunoco LP sold a portfolio of approximately 1,030 company-operated retail fuel outlets in 19 geographic regions, together with ancillary businesses and related assets, including the proprietary Laredo Taco Company brand, for an aggregate purchase price of $3.2 billion.

Significant Organic Growth Projects

Our significant announced organic growth projects in 2018 included the following, as discussed in more detail herein:

- In September 2018, ETO, Magellan Midstream Partners, L.P., MPLX LP and Delek US Holdings, Inc. announced that they have received sufficient commitments to proceed with plans to construct a new 30-inch diameter common carrier pipeline, the Permian Gulf Coast ("PGC") pipeline, to transport crude oil from the Permian Basin to the Texas Gulf Coast region. The transaction structure for this project has not been finalized.

- In August 2018, the Partnership received approval to commence service on 100% of the long-haul contractual commitments on Rover to begin September 1, 2018, and on November 2, 2018, the Partnership announced that it received approval to commence service on the final laterals needed to complete the Rover pipeline project.

- In March 2018, ETO and Satellite Petrochemical USA Corp. ("Satellite") entered into definitive agreements to form a joint venture, Orbit Gulf Coast NGL Exports, LLC ("Orbit"), with the purpose of constructing a new export terminal on the United States Gulf Coast to provide ethane to Satellite for consumption at its ethane cracking facilities in China.

Segment Overview

See Note 16 to our consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" 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, power generators and other third-party pipelines. Through our intrastate transportation and storage segment, we own and operate (through wholly-owned or through joint venture interests) approximately 9,400 miles of natural gas transportation pipelines with approximately 21.1 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas.

We own a 70% interest in the Red Bluff Express Pipeline, a 100-mile intrastate pipeline system that connects our Orla Plant, as well as third-party plants to the Waha Oasis Header.

Energy Transfer operates one of the largest intrastate pipeline systems in the United States providing energy logistics to major trading hubs and industrial 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 (Permian, Barnett, Haynesville and Eagle Ford Shale) through our Oasis pipeline, our ETC Katy pipeline, our natural gas pipeline and storage systems that are referred to as the ET Fuel System, and our HPL System, as further 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 a fee 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 supply sources including other transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users and other pipelines. Through our interstate transportation and storage segment, we directly own and operate approximately 12,200 miles of interstate natural gas pipelines with approximately 10.3 Bcf/d of transportation capacity and another approximately 6,750 miles and 10.5 Bcf/d of transportation capacity through joint venture interests.

Rover Pipeline, completed and available for full commercial operation since November 2018, is a new 713-mile system designed to transport 3.25 Bcf/d of domestically produced natural gas from the Marcellus and Utica Shale production areas to markets across the United States and into Canada.

ETO's vast interstate natural gas network spans the United States from Florida to California and Texas to Michigan, offering a comprehensive array of pipeline and storage services. Our pipelines have the capability to transport natural gas from nearly all Lower 48 onshore and offshore supply basins to customers in the Southeast, Gulf Coast, Southwest, Midwest, Northeast and Canada. Through numerous interconnections with other pipelines, our interstate systems can access virtually any supply or market in the country. As discussed further herein, our interstate segment operations are regulated by the FERC, which has broad regulatory authority over the business and operations of interstate natural gas pipelines.

Lake Charles LNG, our wholly-owned subsidiary, owns an LNG import terminal and regasification facility located on Louisiana's Gulf Coast near Lake Charles, Louisiana. The import terminal has approximately 9.0 Bcf of above ground storage capacity and the regasification facility has a send out capacity of 1.8 Bcf/d. Lake Charles LNG derives all of its revenue from a series of long-term contracts with a wholly-owned subsidiary of Shell.

LCL, our wholly-owned subsidiary, is currently developing a natural gas liquefaction facility for the export of LNG. In December 2015, Lake Charles LNG received authorization from the FERC to site, construct and operate facilities for the liquefaction and export of natural gas. The project would utilize existing dock and storage facilities owned by Lake Charles LNG located on the Lake Charles site.

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 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. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems, that collect natural gas from points near producing wells and transports it to larger pipelines for further transportation.

Treating plants remove carbon dioxide and hydrogen sulfide from natural gas that is higher in carbon dioxide, hydrogen sulfide or certain other contaminants, to ensure that it meets pipeline quality specifications. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream. 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 can be processed to take advantage of favorable margins for NGLs extracted from the gas stream.

Through our midstream segment, we own and operate natural gas gathering and NGL pipelines, natural gas processing plants, natural gas treating facilities and natural gas conditioning facilities with an aggregate processing capacity of approximately 7.9 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 in South Texas, West Texas, New Mexico, North Texas, East Texas, West Virginia, Pennsylvania, Ohio and Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment also includes a 60% interest in Edwards Lime Gathering, LLC, which operates natural gas gathering, oil pipeline and oil stabilization facilities in South Texas and a 75% membership interest in ORS, which operates a natural gas gathering system in the Utica shale in Ohio.

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 transport, store and execute 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.

Our NGL and refined products transportation and services segment includes:

- approximately 4,769 miles of NGL pipelines;
- NGL and propane fractionation facilities with an aggregate capacity of 825 MBbls/d;
- NGL storage facility in Mont Belvieu with a working storage capacity of approximately 45 million Bbls; and
- other NGL storage assets, located at our Cedar Bayou and Hattiesburg storage facilities, and our Nederland, Marcus Hook and Inkster NGL terminals with an aggregate storage capacity of approximately 11 million Bbls.

We are currently constructing a seventh fractionator at our Mont Belvieu facility, which we expect to be operational in the first quarter of 2020. In addition, we are constructing an expansion to the Lone Star Express pipeline, which is expected to be in service early in the fourth quarter of 2020. The NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu.

NGL terminalling services are facilitated by approximately 7 million Bbls of NGL storage capacity. These operations also support our liquids blending activities, including the use of our patented butane blending technology. Refined products operations provide transportation and terminalling services through the use of approximately 2,203 miles of refined products pipelines and approximately 35 active refined products marketing terminals. Our marketing terminals are located primarily in the northeast, midwest and southwest United States, with approximately 8 million Bbls of refined products storage capacity. Our refined products operations utilize our integrated pipeline and terminalling assets, as well as acquisition and marketing activities, to service refined products markets in several regions throughout the United States.

Revenues in this segment are 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. Fees are market-based, negotiated with customers and competitive with regional regulated pipelines and fractionators. Storage revenues are derived from base storage and throughput fees. This segment also derives revenues from the marketing of NGLs and processing and fractionating refinery off-gas.

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. Through our crude oil transportation and services segment, we own and operate (through wholly-owned subsidiaries or joint venture interests) approximately 9,524 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States. This segment includes equity ownership interests in two crude oil pipelines, the Bakken Pipeline system and Bayou Bridge Pipeline. Our crude oil terminalling services operate with an aggregate storage capacity of approximately 38 million Bbls, including approximately 28 million Bbls at our Gulf Coast terminal in Nederland, Texas and approximately 4 million Bbls at our 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 midcontinent United States.

Revenues throughout our crude oil pipeline systems are generated from tariffs paid by shippers utilizing our transportation services. These tariffs are filed with the FERC and other state regulatory agencies, as applicable.

Our crude oil acquisition and marketing activities include the gathering, purchasing, marketing and selling of crude oil. 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.

Investment in Sunoco LP

Sunoco LP is engaged in the distribution of motor fuels to independent dealers, distributors, and other commercial customers and the distribution of motor fuels to end-user customers at retail sites operated by commission agents. Additionally, it receives rental income through the leasing or subleasing of real estate used in the retail distribution of motor fuel. Sunoco LP also operates 75 retail stores located in Hawaii and New Jersey.

Sunoco LP is a distributor of motor fuels and other petroleum products which Sunoco LP supplies to third-party dealers and distributors, to independent operators of commission agent locations and other commercial consumers of motor fuel. Also included in the wholesale operations are transmix processing plants and refined products terminals. Transmix is the mixture of various refined products (primarily gasoline and diesel) created in the supply chain (primarily in pipelines and terminals) when various products interface with each other. Transmix processing plants separate this mixture and return it to salable products of gasoline and diesel.

Sunoco LP is the exclusive wholesale supplier of the iconic Sunoco-branded motor fuel, supplying an extensive distribution network of approximately 5,293 Sunoco-branded company and third-party operated locations throughout the East Coast, Midwest, South Central and Southeast regions of the United States. Sunoco LP believes it is one of the largest independent motor fuel distributors of Chevron, Exxon and Valero branded motor fuel in the United States. In addition to distributing motor fuels, Sunoco LP also distributes other petroleum products such as propane and lubricating oil, and Sunoco LP receives rental income from real estate that it leases or subleases.

Sunoco LP operations primarily consist of fuel distribution and marketing.

Investment in USAC

USAC provides compression services throughout the United States, including the Utica, Marcellus, Permian Basin, Delaware Basin, Eagle Ford, Mississippi Lime, Granite Wash, Woodford, Barnett, Haynesville, Niobrara and Fayetteville shales. USAC provides compression services to its customers primarily in connection with infrastructure applications, including both allowing for the processing and transportation of natural gas through the domestic pipeline system and enhancing crude oil production through artificial lift processes. As such, USAC's compression services play a critical role in the production, processing and transportation of both natural gas and crude oil.

USAC operates a modern fleet of compression units, with an average age of approximately five years. USAC's standard new-build compression units are generally configured for multiple compression stages allowing USAC to operate its units across a broad range of operating conditions. As part of USAC's services, it engineers, designs, operates, services and repairs its compression units and maintains related support inventory and equipment.

USAC provides compression services to its customers under fixed-fee contracts with initial contract terms typically between six months and five years, depending on the application and location of the compression unit. USAC typically continues to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. USAC primarily enters into take-or-pay contracts whereby its customers are required to pay a monthly fee even during periods of limited or disrupted throughput, which enhances the stability and predictability of its cash flows. USAC is not directly exposed to commodity price risk because it does not take title to the natural gas or crude oil involved in its services and because the natural gas used as fuel by its compression units is supplied by its customers without cost to USAC.

USAC's assets and operations are all located and conducted in the United States.

As of December 31, 2018, USAC had 3,597,097 horsepower in its fleet and 131,750 horsepower on order for expected delivery during 2019.

All Other Segment

Operations below the quantitative thresholds are classified as "All other." These include the following:

- Our approximately 8% non-operating interest in PES, which owns a refinery in Philadelphia.
- Our 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.
- Our natural gas compression equipment business which has operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.
- Our wholly-owned subsidiary, Dual Drive Technologies, Ltd. ("DDT"), which provides compression services to customers engaged in the transportation of natural gas, including our other segments.
- Our subsidiaries 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 end-user coal handling facilities.
- PEI Power LLC and PEI Power II, which own and operate a facility in Pennsylvania that generates a total of 75 megawatts of electrical power.

Asset Overview

The descriptions below include summaries of significant assets within our operations. 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.

The following details the assets in our operations:

Intrastate Transportation and Storage

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

Description of Assets	Ownership Interest	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Storage Capacity (Bcf/d)
ET Fuel System	100%	3,150	5.2	11.2
Oasis Pipeline [(1)]	100%	750	2.0	—
HPL System	100%	3,920	5.3	52.5
ETC Katy Pipeline	100%	460	2.4	—
Regency Intrastate Gas	100%	450	2.1	—
Comanche Trail Pipeline	16%	195	1.1	—
Trans-Pecos Pipeline	16%	143	1.4	—
Old Ocean Pipeline, LLC	50%	240	0.2	—
Red Bluff Express Pipeline	70%	100	1.4	—

(1) Includes bi-directional capabilities

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 Pecos, 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 the 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 the 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 1.3 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 gathering system known as the Southeast Texas System and is an important component to maximizing its Southeast Texas System's profitability. The Oasis pipeline enhances the Southeast Texas System by (i) providing access for natural gas gathered on the Southeast Texas System to other third-party supply and market points and interconnecting pipelines and (ii) allowing us to bypass its 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, 2018, we had approximately 12.8 Bcf committed under fee-based arrangements with third parties and approximately 18.7 Bcf stored in the facility for our own account.

- The ETC Katy Pipeline connects three treating facilities, one of which we own, with our gathering system known as Southeast Texas System. The ETC Katy pipeline serves producers in East and North Central Texas and provided access to the Katy Hub. The ETC Katy 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.

- Comanche Trail is a 195-mile intrastate pipeline that delivers natural gas from the Waha Hub near Pecos, Texas to the United States/Mexico border near San Elizario, Texas. The Partnership owns a 16% membership interest in and operates Comanche Trail.

- Trans-Pecos is a 143-mile intrastate pipeline that delivers natural gas from the Waha Hub near Pecos, Texas to the United States/Mexico border near Presidio, Texas. The Partnership owns a 16% membership interest in and operates Trans-Pecos.

- Old Ocean is a 240-mile intrastate pipeline system that delivers natural gas from Ellis County, Texas to Brazoria County, Texas. The Partnership owns a 50% membership interest in and operates Old Ocean.

- The Red Bluff Express Pipeline is an approximately 100-mile intrastate pipeline that runs through the heart of the Delaware basin and connects our Orla Plant, as well as third-party plants to the Waha Oasis Header. An expansion of the Red Bluff Express Pipeline is expected to be in service in the second half of 2019. The Partnership owns a 70% membership interest in and operates Red Bluff Express.

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	50%	5,344	3.4	—
Transwestern Pipeline	100%	2,614	2.1	—
Panhandle Eastern Pipe Line (1)	100%	6,402	2.8	73.4
Trunkline Gas Company	100%	2,231	0.9	13.0
Tiger Pipeline	100%	197	2.4	—
Fayetteville Express Pipeline	50%	185	2.0	—
Sea Robin Pipeline	100%	785	2.0	—
Rover Pipeline	32.6%	713	3.25	—
Midcontinent Express Pipeline	50%	512	1.8	—
Gulf States	100%	10	0.1	—

(1) Natural gas storage assets are owned by Pan Gas Storage LLC (d.b.a Southwest Gas Storage Company.)

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

- Florida Gas Transmission Pipeline ("FGT") has mainline capacity of 3.4 Bcf/d and approximately 5,344 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 60% of the natural gas consumed in the state. In addition, FGT's system operates and maintains multiple 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, industrial end-users and local distribution companies. FGT is owned by Citrus, a 50/50 joint venture with KMI.

- Transwestern Pipeline transports natural gas supply from 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. The system has bi-directional capabilities and can access Texas and midcontinent connecting pipelines and natural gas market hubs, as well as major western markets in Arizona, Nevada and California. Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users.

- 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. Panhandle contracts for over 73 Bcf of natural gas storage.

- Trunkline Gas Company'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. Trunkline has one natural gas storage field located in Louisiana.

- Tiger Pipeline is a bi-directional system that extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to multiple interstate pipelines.

- Fayetteville Express Pipeline originates near Conway County, Arkansas and continues eastward to Panola County, Mississippi with multiple pipeline interconnections along the route. Fayetteville Express Pipeline is owned by a 50/50 joint venture with KMI.

- Sea Robin Pipeline's system consists of two offshore Louisiana natural gas supply pipelines extending 120 miles into the Gulf of Mexico.

- Rover Pipeline is a large diameter pipeline with total capacity to transport 3.25 Bcf/d natural gas from processing plants in West Virginia, Eastern Ohio and Western Pennsylvania for delivery to other pipeline interconnects in Ohio and Michigan, where the gas is delivered for distribution to markets across the United States, as well as to Ontario, Canada.

- Midcontinent Express Pipeline originates near Bennington, Oklahoma and traverses 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, the operator of the system.

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

Regasification Facility

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

Liquefaction Project

LCL, our wholly-owned subsidiary, is in the process of developing an LNG liquefaction project at the site of our Lake Charles LNG import terminal and regasification facility. The liquefaction facility would 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. The liquefaction project is expected to consist of three LNG trains with a combined design nameplate outlet capacity of 16.45 metric tonnes per annum. Once completed, the liquefaction project will enable LCL to liquefy domestically produced natural gas and export it as LNG. On June 18, 2017, LCL signed a memorandum of understanding with Korea Gas Corporation and Shell to study the feasibility of a joint development of the Lake Charles liquefaction project. LCL and Shell are actively involved in a variety of activities related to the development of the project. LCL has also been marketing LNG offtake to numerous potential customers in Asia and Europe.

The export of LNG produced by the liquefaction project from the United States would be undertaken under long-term export authorizations issued by the DOE to LCL. In March 2013, LCL obtained a DOE authorization to export LNG to countries with which the United States has or will have Free Trade Agreements ("FTA") for trade in natural gas (the "FTA Authorization"). In July 2016, LCL also 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 addition, LCL received its wetlands permits from the United States 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.

Midstream

The following details our assets in its midstream operations:

Description of Assets	Net Gas Processing Capacity (MMcf/d)
South Texas Region:	
Southeast Texas System	410
Eagle Ford System	1,920
Ark-La-Tex Region	1,442
North Central Texas Region	700
Permian Region	2,340
Midcontinent Region	860
Eastern Region	200

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 ETC Katy Pipeline and is also connected to the Oasis Pipeline. The Southeast Texas System includes two natural gas processing plants (La Grange and Alamo) with aggregate capacity of 410 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 1.92 Bcf/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 870 MMcf/d.
- 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, a 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 an NGL pipeline that provides connections to the Mont Belvieu market for NGLs produced from our processing plants. Collectively, the ten natural gas processing facilities (Dubach, Dubberly, Lisbon, Salem, Elm Grove, Minden, Ada, Brookeland, Lincoln Parish and Mt. Olive) have an aggregate capacity of 1.3 Bcf/d.
- Through the gathering and processing systems described above and their interconnections with RIGS in north Louisiana, as well as other pipelines, 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 700 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 midcontinent 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 eleven processing facilities (Waha, Coyanosa, Red Bluff, Halley, Jal, Keyston, Tippet, Orla, Panther, Rebel and Arrowhead) with an aggregate processing capacity of 2.02 Bcf/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 50% 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.

Midcontinent Region:

- The Midcontinent 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 Midcontinent assets are extensive systems that gather, compress and dehydrate low-pressure gas. The Midcontinent 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 860 MMcf/d.

- We operate our Midcontinent 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 eleven counties in Pennsylvania, four counties in Ohio, three counties in West Virginia, and gather natural gas from the Marcellus and Utica basins. Our Eastern Region assets include approximately 600 miles of natural gas gathering pipeline, natural gas trunklines, fresh-water pipelines, and nine gathering and processing systems, as well as the 200 MMcf/d Revolution processing plant, which feeds into our Mariner East and Rover pipeline systems.
- We also own a 51% membership interest in Aqua – ETC Water Solutions LLC, a joint venture that transports and supplies fresh water to natural gas producers drilling in the Marcellus Shale in Pennsylvania.
- We own a 75% membership interest in ORS. On behalf of ORS, we operate its Ohio Utica River System, which consists of 47 miles of 36-inch, 13 miles of 30-inch and 3 miles of 24-inch gathering trunklines, that delivers up to 3.6 Bcf/d to Rockies Express Pipeline, Texas Eastern Transmission, Leach Xpress, Rover and DEO TPL-18.

NGL and Refined Products Transportation and Services

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

Description of Assets	Miles of Liquids Pipeline [2]	Pipeline Throughput Capacity (MBbls/d)	NGL Fractionation / Processing Capacity (MBbls/d)	Working Storage Capacity (MBbls)
Liquids Pipelines:				
Lone Star Express	535	507	—	—
West Texas Gateway Pipeline	512	240	—	—
Lone Star	1,617	120	—	—
Mariner East	670	345		
Mariner South	97	200		
Mariner West	395	50		
Other NGL Pipelines	943	591	—	—
Liquids Fractionation and Services Facilities:				
Mont Belvieu Facilities	163	42	790	45,500
Sea Robin Processing Plant [1]	—	—	26	—
Refinery Services [1]	103	—	35	—
Hattiesburg Storage Facilities	—	—	—	3,000
Cedar Bayou	—	—	—	1,600
NGL Terminals:				
Nederland	—	—	—	1,200
Marcus Hook Industrial Complex	—	—	132	5,000
Inkster	—	—	—	800
Refined Products Pipelines	2,203	800	—	—
Refined Products Terminals:				
Eagle Point	—	—	—	6,000
Marcus Hook Industrial Complex	—	—	—	1,000
Marcus Hook Tank Farm	—	—	—	2,000
Marketing Terminals	—	—	—	8,000

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

(2) Miles of pipeline as reported to PHMSA.

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

- The Lone Star Express System is an interstate 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. An expansion of the pipeline is currently underway, which will add approximately 400 MBbls/d of NGL pipeline capacity from Lone Star's pipeline system near Wink, Texas to the Lone Star Express 30-inch pipeline south of Fort Worth, Texas. It is expected to be in service by the fourth quarter of 2020.
- The West Texas Gateway Pipeline transports NGLs produced in the Permian and Delaware Basins and the Eagle Ford Shale to Mont Belvieu, Texas.
- 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, began service in December 2018.
- The Mariner South liquids pipeline delivers export-grade propane and butane products from Lone Star's Mont Belvieu, Texas storage and fractionation complex to our marine terminal in Nederland, Texas.
- The Mariner West pipeline provides transportation of ethane from the Marcellus shale processing and fractionating areas in Houston, Pennsylvania to Marysville, Michigan and the Canadian border.
- Refined products pipelines include approximately 2,203 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 our 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 MBbls/d, the 45-mile Freedom pipeline with a capacity of 56 MBbls/d, the 20-mile Spirit pipeline with a capacity of 20 MBbls/d and a 50% interest in the 87-mile Liberty pipeline with a capacity of 140 MBbls/d.
- Our Mont Belvieu storage facility is an integrated liquids storage facility with over 46 million Bbls of salt dome capacity providing 100% fee-based cash flows. The Mont Belvieu storage facility has access to multiple NGL and refined products 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. Fractionator VI was placed in service in February 2019, Fractionator VII is currently under construction and is scheduled to be operational by the first quarter of 2020.
- Sea Robin is a rich gas processing plant located on the Sea Robin Pipeline in southern Louisiana. The plant 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 unit and an O-grade NGL fractionation / Refinery-Grade Propylene ("RGP") splitting complex located along the Mississippi River refinery corridor in southern Louisiana. The off-gas processing unit cryogenically processes refinery off-gas, and the fractionation / RGP splitting complex fractionates the streams into higher value components. The O-grade fractionator and RGP splitting complex, located in Geismar, Louisiana, is connected by approximately 103 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 Cedar Bayou storage facility is an integrated liquids storage facility with approximately 1.6 million Bbls of tank storage, generating revenues from fixed fee storage contracts, throughput fees, and revenue from blending butane into refined gasoline.

- The Nederland terminal, in addition to crude oil activities, also provides approximately 1 million Bbls 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 exported via ship.
- The Marcus Hook Industrial Complex includes fractionation, terminalling and storage assets, with a capacity of approximately 2 million Bbls of NGL storage capacity in underground caverns, 3 million Bbls of above-ground refrigerated storage, and related commercial agreements. The terminal has a total active refined products storage capacity of approximately 1 million Bbls. The facility can receive NGLs and refined products via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck. In addition to providing NGL storage and terminalling services to both affiliates and third-party customers, the Marcus Hook Industrial Complex currently serves as an off-take outlet for our Mariner East 1 pipeline system.
- The Inkster terminal, located near Detroit, Michigan, consists of multiple salt caverns with a total storage capacity of approximately 800 MBbls 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 35 refined products terminals with an aggregate storage capacity of approximately 8 million Bbls 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 Bbls, and provides customers with access to the facility via ship, barge and pipeline. The terminal can deliver via ship, 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 Tank Farm has a total refined products storage capacity of approximately 2 million Bbls of refined products storage. The tank farm historically served ETC Sunoco Holdings LLC ("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 our refined products pipelines.
- The Eastern refined products pipelines consists of approximately 561 miles of 6-inch to 24-inch diameters refined product pipelines in Eastern, Central and North Central Pennsylvania, approximately 162 miles of 8-inch refined products pipeline in western New York and approximately 183 miles of various diameters refined products pipeline in New Jersey (including 80 miles of the 16-inch diameter Harbor Pipeline).
- The midcontinent refined products pipelines primarily consists of approximately 294 miles of 3-inch to 12-inch refined products pipelines in Ohio, approximately 85 miles of 6-inch to 12-inch refined products pipeline in Western Pennsylvania and approximately 52 miles of 8-inch refined products pipeline in Michigan.
- The Southwest refined products pipelines is located in Eastern Texas and consists primarily of approximately 375 miles of 8-inch diameter refined products pipeline.
- The Inland refined products pipeline, approximately 486 miles of pipeline in Ohio, consists of 72 miles of 12-inch diameter refined products pipeline in Northwest Ohio, 135 miles of 10-inch diameter refined products pipeline in vicinity of Columbus, Ohio, 53 miles of 8-inch diameter refined products pipeline in western Ohio and the remaining refined products pipeline primarily consists of 5 and 6-inch diameter pipeline in Northeast Ohio.
- This segment also includes the following joint ventures: 15% membership interest in the Explorer Pipeline Company, a 1,850-mile pipeline which originates from refining centers in Beaumont, Port Arthur, and Houston, Texas and extends to Chicago, Illinois; 31% membership interest in the Wolverine Pipe Line Company, a 700-mile pipeline that originates from Chicago, Illinois and extends to Detroit, Grand Haven, and Bay City, Michigan; 17% membership interest in the West Shore Pipe Line Company, a 650-mile pipeline which originates in Chicago, Illinois and extends to Madison and Green Bay, Wisconsin; and a 14% membership interest in the Yellowstone Pipe Line Company, a 700-mile pipeline which originates from Billings, Montana and extends to Moses Lake, Washington.

Crude Oil Transportation and Services

The following details our pipelines and terminals in its crude oil transportation and services operations:

Description of Assets	Ownership Interest	Miles of Crude Pipeline [(1)]	Working Storage Capacity (MBbls)
Dakota Access Pipeline	36.40%	1,158	—
Energy Transfer Crude Oil Pipeline	36.40%	760	—
Bayou Bridge Pipeline	60%	49	—
Permian Express Pipelines	87.7%	1,712	—
Other Crude Oil Pipelines	100%	5,845	—
Nederland Terminal	100%	—	28,000
Fort Mifflin Terminal	100%	—	3,570
Eagle Point Terminal	100%	—	1,000
Midland Terminal	100%	—	2,000
Marcus Hook Industrial Complex	100%	—	1,000
Patoka, Illinois Terminal	87.7%	—	2,000

(1) Miles of pipeline as reported to PHMSA.

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

Crude Oil Pipelines

Our crude oil pipelines consist of approximately 9,524 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States, including our wholly-owned interests in West Texas Gulf, Permian Express Terminal LLC, and 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.

- *Bakken Pipeline.* Dakota Access and ETCO are collectively referred to as the "Bakken Pipeline." The Bakken Pipeline is a 1,918 mile pipeline with capacity of 570 MBbls/d, that transports domestically produced crude oil from the Bakken/Three Forks production areas in North Dakota to a storage and terminal hub outside of Patoka, Illinois, or to gulf coast connections including our crude terminal in Nederland Texas.

  The pipeline transports light, sweet crude oil from North Dakota to major refining markets in the Midwest and Gulf Coast regions.

  Dakota Access went into service on June 1, 2017 and consists of approximately 1,158 miles of 12, 20, 24 and 30-inch diameter pipeline traversing North Dakota, South Dakota, Iowa and Illinois. Crude oil transported on the Dakota Access originates at six terminal locations in the North Dakota counties of Mountrail, Williams and McKenzie. The pipeline delivers the crude oil to a hub outside of Patoka, Illinois where it can be delivered to the ETCO Pipeline for delivery to the Gulf Coast, or can be transported via other pipelines to refining markets throughout the Midwest.

  ETCO went into service on June 1, 2017 and consists of approximately 691 miles of mostly 30-inch converted natural gas pipeline and 69 miles of new 30-inch pipeline from Patoka, Illinois to Nederland, Texas, where the crude oil can be refined or further transported to additional refining markets.

- *Bayou Bridge Pipeline.* The Bayou Bridge Pipeline is a joint venture between ETO and Phillips 66, in which ETO has a 60% ownership interest and serves as the operator of the pipeline. Phase I of the pipeline, which consists of a 30-inch pipeline from Nederland, Texas to Lake Charles, Louisiana, went into service in April 2016. Phase II of the pipeline, which will consist of 24-inch pipe from Lake Charles, Louisiana to St. James, Louisiana, with commercial operations expected to begin in March 2019.

When completed the Bayou Bridge Pipeline will have a capacity expandable to approximately 480 MBbls/d of light and heavy crude oil from different sources to the St. James crude oil hub, which is home to important refineries located in the Gulf Coast region.

- *Permian Express Pipelines.* The Permian Express pipelines are part of the PEP joint venture and include Permian Express 1, Permian Express 2, Permian Express 3, which became fully operational in September 2018, Permian Longview and Louisiana Access pipelines, as well as the Longview to Louisiana and Nederland Access pipelines contributed to this joint venture by ExxonMobil. These pipelines are comprised of crude oil trunk pipelines and crude oil gathering pipelines in Texas and Oklahoma and provide takeaway capacity from the Permian Basin, which origins in multiple locations in Western Texas.

- Other Crude Oil pipelines include 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 MPLX's Samaria, Michigan tank farm, which supplies its Marathon Petroleum Corporation's refinery in Detroit, Michigan.

  We also 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 our crude oil acquisition and marketing activities business is the primary shipper on our Oklahoma crude oil system.

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, petrochemicals, and bunker oils (used for fueling ships and other marine vessels). The terminal currently has a total storage capacity of approximately 28 million Bbls in approximately 150 above ground storage tanks with individual capacities of up to 660 MBbls.

  The Nederland terminal can receive crude oil at four of its five ship docks and four barge berths. The four ship docks are capable of receiving over 2 million Bbls/d of crude oil. In addition to our 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 caverns near Winnie, Texas, which have an aggregate storage capacity of approximately 395 million Bbls.

  The Nederland Terminal can deliver crude oil and other petroleum products via pipeline, barge and ship. The terminal has three 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 MBbls. 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 Bbls. Darby Creek receives crude oil from the Fort Mifflin terminal and Hog Island wharf via our pipelines. The tank farm then stores the crude oil and transports it to the PES refinery via our 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 Bbls and can receive crude oil via barge and rail and deliver via ship and 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 Bbls of crude oil storage, a combined 14 lanes of truck loading and unloading, and provides access to the Permian Express 2 transportation system.
- *Marcus Hook Industrial Complex.* The Marcus Hook Industrial Complex can receive crude oil via marine vessel and can deliver via marine vessel and pipeline. The terminal has a total active crude oil storage capacity of approximately 1 million Bbls.
- *Patoka, Illinois Terminal.* The Patoka, Illinois terminal is a tank farm and was contributed by ExxonMobil to the PEP joint venture and is located in Marion County, Illinois. The facility includes 234 acres of owned land and provides for approximately 2 million Bbls of crude oil storage.

Crude Oil Acquisition and Marketing

Our crude oil acquisition and marketing 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.

Investment in Sunoco LP

Sunoco LP is a distributor of motor fuels and other petroleum products which Sunoco LP supplies to third-party dealers and distributors, to independent operators of commission agent locations and other commercial consumers of motor fuel. Also included in the wholesale operations are transmix processing plants and refined products terminals. Transmix is the mixture of various refined products (primarily gasoline and diesel) created in the supply chain (primarily in pipelines and terminals) when various products interface with each other. Transmix processing plants separate this mixture and return it to salable products of gasoline and diesel.

Sunoco LP is the exclusive wholesale supplier of the iconic Sunoco-branded motor fuel, supplying an extensive distribution network of approximately 5,293 Sunoco-branded company and third-party operated locations throughout the East Coast, Midwest, South Central and Southeast regions of the United States. Sunoco LP believes it is one of the largest independent motor fuel distributors of Chevron, Exxon and Valero branded motor fuel in the United States. In addition to distributing motor fuels, Sunoco LP also distributes other petroleum products such as propane and lubricating oil, and Sunoco LP receives rental income from real estate that it leases or subleases.

Sunoco LP operations primarily consist of fuel distribution and marketing.

Sunoco LP's Fuel Distribution and Marketing Operations

Sunoco LP's fuel distribution and marketing operations are conducted by the following consolidated subsidiaries:

- Sunoco, LLC ("Sunoco LLC"), a Delaware limited liability company, primarily distributes motor fuel in 30 states throughout the East Coast, Midwest, South Central and Southeast regions of the United States. Sunoco LLC also processes transmix and distributes refined product through its terminals in Alabama, Texas, Arkansas and New York;
- Sunoco Retail LLC ("Sunoco Retail"), a Pennsylvania limited liability company, owns and operates retail stores that sell motor fuel and merchandise primarily in New Jersey;
- Aloha Petroleum LLC, a Delaware limited liability company, distributes motor fuel and operates terminal facilities on the Hawaiian Islands; and
- Aloha Petroleum, Ltd. ("Aloha"), a Hawaii corporation, owns and operates retail stores on the Hawaiian Islands.

Sunoco LP purchases motor fuel primarily from independent refiners and major oil companies and distributes it across more than 30 states throughout the East Coast, Midwest, South Central and Southeast regions of the United States, as well as Hawaii to approximately:

- 75 company owned and operated retail stores;

- 554 independently operated consignment locations where Sunoco LP sells motor fuel to customers under commission agent arrangements with such operators;
- 6,741 convenience stores and retail fuel outlets operated by independent operators, which are referred to as "dealers" or "distributors," pursuant to long-term distribution agreements; and
- 2,714 other commercial customers, including unbranded convenience stores, other fuel distributors, school districts and municipalities and other industrial customers.

Sunoco LP's Other Operations

Sunoco LP's other operations include retail operations in Hawaii and New Jersey, credit card services, franchise royalties, as well as an ethanol plant that Sunoco LP recently entered into an agreement to divest.

Investment in USAC

The following details the assets of USAC:

USAC's modern, standardized compression unit fleet is powered primarily by the Caterpillar, Inc.'s 3400, 3500 and 3600 engine classes, which range from 401 to 5,000 horsepower per unit. These larger horsepower units, which USAC defines as 400 horsepower per unit or greater, represented 85.8% of its total fleet horsepower (including compression units on order) as of December 31, 2018. In addition, a portion of its fleet consists of smaller horsepower units ranging from 40 horsepower to 399 horsepower that are primarily used in gas lift applications.

The following table provides a summary of USAC's compression units by horsepower as of December 31, 2018:

Unit Horsepower	Fleet Horsepower	Number of Units	Horsepower on Order [1]	Number of Units on Order	Total Horsepower	Total Number of Units
Small horsepower						
<400	528,084	3,101	900	4	528,984	3,105
Large horsepower						
>400 and <1,000	429,203	735	—	—	429,203	735
>1,000	2,639,810	1,650	130,850	55	2,770,660	1,705
Total large horsepower	3,069,013	2,385	130,850	55	3,199,863	2,440
Total horsepower	3,597,097	5,486	131,750	59	3,728,847	5,545

(1) As of December 31, 2018, USAC had 131,750 horsepower on order for delivery during 2019.

All Other

The following details our assets in the all other segment.

PES

We have a non-controlling interest in PES, currently comprising approximately 8% of PES' outstanding common shares. PES owns a refinery in Philadelphia.

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 DDT, which provides compression services to customers engaged in the transportation of natural gas, including our subsidiaries in 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, 2018, we owned or controlled approximately 761 million tons of proven and probable coal reserves in central and northern Appalachia, properties in eastern Kentucky, 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.

Business Strategy

We believe we have engaged, and will continue to engage, in a well-balanced plan for growth through strategic acquisitions, internally generated expansion, measures aimed at increasing the profitability of our existing assets and executing cost control measures where appropriate to manage our operations.

We intend to continue to operate as a diversified, growth-oriented limited partnership. We believe that by pursuing independent operating and growth strategies we will be best positioned to achieve our objectives. We balance our desire for growth with our goal of preserving a strong balance sheet, ample liquidity and investment grade credit metrics.

Following is a summary of the business strategies of our core businesses:

Growth through acquisitions. We intend to continue to make strategic acquisitions that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing assets while supporting our investment grade credit ratings.

Engage in construction and expansion opportunities. We intend to leverage our existing infrastructure and customer relationships by constructing and expanding systems to meet new or increased demand for midstream and transportation services.

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

Enhance profitability of existing assets. We intend to increase the profitability of our existing asset base by adding new volumes under long-term producer commitments, undertaking additional initiatives to enhance utilization and reducing costs by improving operations.

Competition

Natural Gas

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

We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major integrated oil and gas companies, interstate and intrastate pipelines and other companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.

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

NGL

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

Crude Oil and Products

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

With respect to competition from other pipelines, the primary competitive factors consist of transportation charges, access to crude oil supply and market demand. Competitive factors in crude oil purchasing and marketing include price and contract flexibility, quantity and quality of services, and accessibility to end markets.

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

Wholesale Fuel Distribution and Retail Marketing

In our wholesale fuel distribution business, we compete primarily with other independent motor fuel distributors. The markets for distribution of wholesale motor fuel and the large and growing convenience store industry are highly competitive and fragmented, which results in narrow margins. We have numerous competitors, some of which may have significantly greater resources and name recognition than we do. Significant competitive factors include the availability of major brands, customer service, price, range of services offered and quality of service, among others. We rely on our ability to provide value-added and reliable service and to control our operating costs in order to maintain our margins and competitive position.

In our retail business, we face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations of large integrated oil companies, independent gasoline service stations, convenience stores, fast food stores, supermarkets, drugstores, dollar stores, club stores and other similar retail outlets, some of which are well-recognized national or regional retail systems. The number of competitors varies depending on the geographical area. It also varies with gasoline and convenience store offerings. The principal competitive factors affecting our retail marketing operations include gasoline and diesel acquisition costs, site location, product price, selection and quality, site appearance and cleanliness, hours of operation, store safety, customer loyalty and brand recognition. We compete by pricing gasoline competitively, combining our retail gasoline business with convenience stores that provide a wide variety of products, and using advertising and promotional campaigns.

Credit Risk and Customers

Credit risk refers to the risk that a counterparty may default on its contractual obligations resulting in a loss to the Partnership. Credit policies have been approved and implemented to govern the Partnership's portfolio of counterparties with the objective of mitigating credit losses. These policies establish guidelines, controls and limits to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential counterparties, monitoring agency credit ratings, and by implementing credit practices that limit exposure according to the risk profiles of the counterparties. Furthermore, the Partnership may, at times, require collateral under certain circumstances to mitigate credit risk as necessary. 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 industrial end-users, 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.

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

During the year ended December 31, 2018, none of our customers individually accounted for more than 10% of our consolidated revenues.

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

The FERC's NGA authority includes the power to:

- approve the siting, construction and operation of new facilities;
- review and approve transportation rates;
- determine the types of services our regulated assets are permitted to perform;
- regulate the terms and conditions associated with these services;
- permit the extension or abandonment of services and facilities;
- require the maintenance of accounts and records; and
- authorize the acquisition and disposition of facilities.

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

The maximum rates to be charged by NGA-jurisdictional natural gas companies and their terms and conditions for service are required to be on file with the FERC. Most natural gas companies are authorized to offer discounts from their FERC-approved maximum just and reasonable rates when competition warrants such discounts. Natural gas companies are also generally permitted to offer negotiated rates different from rates established in their tariff if, among other requirements, such companies' tariffs offer a cost-based recourse rate available to a prospective shipper as an alternative to the negotiated rate. Natural gas companies must make offers of rate discounts and negotiated rates on a basis that is not unduly discriminatory. Existing tariff rates may be challenged by complaint or on FERC's own motion, and if found unjust and unreasonable, may be altered on a prospective basis from no earlier than the date of the complaint or initiation of a proceeding by the FERC. The FERC must also approve all rate changes. We cannot guarantee that the FERC will allow us to charge rates that fully recover our costs or continue to pursue its approach of pro-competitive policies.

For two of our NGA-jurisdictional natural gas companies, Tiger and Fayetteville Express, the large majority of capacity in those pipelines is subscribed for lengthy terms under FERC-approved negotiated rates. However, as indicated above, cost-based recourse rates are also offered under their respective tariffs.

Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (i) to defraud using any device, scheme or artifice; (ii) to make any untrue statement of material fact or omit a material fact; or (iii) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("CEA"). With regard to our physical purchases and sales of natural gas, NGLs or other energy commodities; our transportation of these energy commodities; and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess or seek civil penalties in excess of $1.1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

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

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

Our intrastate natural gas operations are also subject to regulation by various agencies in Texas, principally the TRRC. Our intrastate pipeline and storage operations in Texas are also subject to the Texas Utilities Code, as implemented by the TRRC. Generally, the TRRC is vested with authority to ensure that rates, operations and services of gas utilities, including intrastate pipelines, are just and reasonable and not discriminatory. The rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a customer or TRRC complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates. Failure to comply with the Texas Utilities Code can result in the imposition of administrative, civil and criminal remedies.

Our NGL pipelines and operations are subject to state statutes and regulations which could impose additional environmental, safety and operational requirements relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL transportation systems. In some jurisdictions, state public utility commission oversight may include the possibility of fines, penalties and delays in construction related to these regulations. In addition, the rates, terms and conditions of service for shipments of NGLs on our pipelines are subject to regulation by FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 (the "EPAct of 1992") if the NGLs are transported in interstate or foreign commerce whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all NGLs shipped on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

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

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

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those operations of the natural gas industry. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC's regulatory changes may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action in a manner that is materially different from other natural gas marketers with whom we compete.

Regulation of Gathering Pipelines. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own a number of natural gas pipelines in Texas, Louisiana and West Virginia that we believe meet the traditional tests the FERC uses to establish a pipeline's status as a gathering pipeline not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and varying interpretations, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by the FERC, the courts and Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

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

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

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

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

Regulation of Interstate Crude Oil, NGL and Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the ICA, the EPAct of 1992, and related rules and orders. The ICA requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory and that such rates and terms and conditions of service be filed with the FERC. This statute also permits interested persons to challenge proposed new or changed rates. The FERC is authorized to suspend the effectiveness of such rates for up to seven months, though rates are typically not suspended for the maximum allowable period. If the FERC finds that the new or changed rate is unlawful, it may require the carrier to pay refunds for the period that the rate was in effect. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

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

For many locations served by our product and crude pipelines, we are able to establish negotiated rates. Otherwise, we are permitted to charge cost-based rates, or in many cases, grandfathered rates based on historical charges or settlements with our customers. To the extent we rely on cost-of-service ratemaking to establish or support our rates, the issue of the proper allowance for federal and state income taxes could arise. In 2005, FERC issued a policy statement stating that it would permit common carriers, among others, to include an income tax allowance in cost-of-service rates to reflect actual or potential tax liability attributable to a regulated entity's operating income, regardless of the form of ownership. Under FERC's policy, a tax pass-through entity seeking such an income tax allowance must establish that its partners or members have an actual or potential income tax liability on the regulated entity's income. Whether a pipeline's owners have such actual or potential income tax liability is subject to review by FERC on a case-by-case basis. Although this policy is generally favorable for common carriers that are organized as pass-through entities, it still entails rate risk due to the FERC's case-by-case review approach. The application of this policy, as well as any decision by FERC regarding our cost of service, may also be subject to review in the courts. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued an opinion in United Airlines, Inc., et al. v. FERC, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a master limited partnership, or MLP, to include an income tax allowance in the cost of service underlying its rates, in addition to the discounted cash flow return on equity, would not result in the pipeline partnership owners double recovering their income taxes. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. In December 2016, FERC issued a Notice of Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs. FERC requested comments regarding how to address any double recovery resulting from the Commission's current income tax allowance and rate of return policies. The comment period with respect to the notice of inquiry ended in April 2017.

In March 2018, FERC issued a Revised Policy Statement on Treatment of Income Taxes in which FERC found that an impermissible double recovery results from granting an MLP pipeline both an income tax allowance and a return on equity pursuant to FERC's discounted cash flow methodology. FERC revised its previous policy, stating that it would no longer permit an MLP pipeline to recover an income tax allowance in its cost of service. FERC stated it will address the application of the United Airlines decision to non-MLP partnership forms as those issues arise in subsequent proceedings. Further, FERC stated that it will incorporate the effects of the post- United Airlines policy changes and the Tax Cuts and Jobs Act of 2017 on industry-wide crude oil pipeline costs in the 2020 five-year review of the crude oil pipeline index level. FERC will also apply the revised Policy Statement and the Tax Cuts and Jobs Act of 2017 to initial crude oil pipeline cost-of-service rates and cost-of-service rate changes on a going-forward basis under FERC's existing ratemaking policies, including cost-of-service rate proceedings resulting from shipper-initiated complaints. In July 2018, FERC dismissed requests for rehearing and clarification of the March 2018 Revised Policy Statement, but provided further guidance, clarifying that a pass-through entity will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double recovery of investors' income tax costs.

EPAct 1992 required FERC to establish a simplified and generally applicable methodology to adjust tariff rates for inflation for interstate petroleum pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods, or PPIFG. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2011 and ending June 30, 2016, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPIFG plus 2.65%. Beginning July 1, 2016, the indexing method provided for annual changes equal to the change in PPIFG plus 1.23%. The indexing methodology is applicable to existing rates, including grandfathered rates, with the exclusion of market-based rates. A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so and rate increases made under the index are presumed to be just and reasonable unless a protesting party can demonstrate that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. Under the indexing rate methodology, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling. In October 2016, FERC issued an Advance Notice of Proposed Rulemaking seeking comment on a number of proposals, including: (1) whether the Commission should deny any increase in a rate ceiling or annual index-based rate increase if a pipeline's revenues exceed total costs by 15% for the prior 2 years; (2) a new percentage comparison test that would deny a proposed increase to a pipeline's rate or ceiling level greater than 5% above the barrel-mile cost changes; and (3) a requirement that all pipelines file indexed ceiling levels annually, with the ceiling levels subject to challenge and restricting the pipeline's ability to carry forward the full indexed increase to a future period. The comment period with respect to the proposed rules ended in March 2017. FERC has taken no further action on the proposed rule to date.

Finally, in November 2017 FERC responded to a petition for declaratory order and issued an order that may have significant impacts on the way a marketer of crude oil or petroleum products that is affiliated with an interstate pipeline can price its services if those services include transportation on an affiliate's interstate pipeline. In particular, FERC's November 2017 order prohibits buy/sell arrangements by a marketing affiliate if: (i) the transportation differential applicable to its affiliate's interstate pipeline transportation service is at a discount to the affiliated pipeline's filed rate for that service; and (ii) the pipeline affiliate subsidizes the loss. Several parties have requested that FERC clarify its November 2017 order or, in the alternative, grant rehearing of the November 2017 order. FERC extended the timeframe to respond to such requests in January 2018, but has not yet taken final action. We are unable to predict how FERC will respond to such requests. Depending on how FERC responds, it could have an impact on the rates we are permitted to charge.

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

In addition, as noted above, the rates, terms and conditions for shipments of crude oil, NGLs or products on our pipelines could be subject to regulation by FERC under the ICA and the EPAct of 1992 if the crude oil, NGLs or products are transported in interstate or foreign commerce whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all crude oil, NGLs or products shipped on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

Regulation of Pipeline Safety. Our pipeline operations are subject to regulation by the DOT, through the PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas ("HCAs"), which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Failure to comply with the pipeline safety laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays in permitting or the performance of projects, or the issuance of injunctions limiting or prohibiting some or all of our operations in the affected area.

The HLPSA and NGPSA have been amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Pipeline Safety Act"). The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2011 Pipeline Safety Act doubled the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1 million to $2 million for a related series of violations, but provided that these maximum penalty caps do not apply to certain civil enforcement actions. In November 2018, to account for inflation, PHMSA issued a final rule increasing those maximum civil penalties to $213,268 per day, with a maximum of $2,132,679 for a series of violations. The 2016 Pipeline Safety Act extended PHMSA's statutory mandate through 2019 and, among other things, require PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities, which is expected to be finalized in 2019. The 2016 Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid or natural gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. The states in which we conduct operations typically have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines. Under such state regulatory programs, states have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, PHMSA and individual states may pass or implement additional safety requirements that could result in increased compliance costs for us and other companies in our industry. For example, federal construction, maintenance and inspection standards under the NGPSA that apply to pipelines in relatively populated areas may not apply to gathering lines running through rural regions. This "rural gathering exemption" under the NGPSA presently exempts substantial portions of our gathering facilities located outside of cities, towns or any area designated as residential or commercial from jurisdiction under the NGPSA, but does not apply to our intrastate natural gas pipelines. In recent years, the PHMSA has considered changes to this rural gathering exemption, including publishing an advance notice of proposed rulemaking relating to gas pipelines in 2011, in which the agency sought public comment on possible changes to the definition of "high consequence areas" and "gathering lines" and the strengthening of pipeline integrity management requirements. In April 2016, pursuant to one of the requirements of the 2011 Pipeline Safety Act, PHMSA published a proposed rulemaking that, among other things, would expand certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; require natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("MAOP"); and require certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for natural gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has not yet finalized the March 2016 proposed rulemaking, but is expected to do so in 2019.

In January 2017, PHMSA issued a final rule amending federal safety standards for hazardous liquid pipelines. The final rule is the latest step in a lengthy rulemaking process that began in 2010 with a request for comments and continued with publication of a rulemaking proposal in October 2015. The general effective date of this final rule is six months from publication in the Federal Register, but it is currently subject to further administrative review in connection with the transition of Presidential administrations and thus, implementation of this final rule remains uncertain. The final rule addresses several areas including reporting requirements for gravity and unregulated gathering lines, inspections after weather or climatic events, leak detection system requirements, revisions to repair criteria and other integrity management revisions. In addition, PHMSA issued regulations on January 23, 2017, on operator qualification, cost recovery, accident and incident notification and other pipeline safety changes that are now effective. These regulations are also subject, however, to potential further review in connection with the transition of Presidential administrations. A final rulemaking is expected in 2019. Historically, our pipeline safety costs have not had a material adverse effect on our business or results of operations but there is no assurance that such costs will not be material in the future, whether due to elimination of the rural gathering exemption or otherwise due to changes in pipeline safety laws and regulations.

In another example of how future legal requirements could result in increased compliance costs, notwithstanding the applicability of the federal OSHA's Process Safety Management ("PSM") regulations and the EPA's Risk Management Planning ("RMP") requirements at regulated facilities, PHMSA and one or more state regulators, including the TRRC, have in recent years, expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid pipeline safety requirements. To the extent that these actions are pursued by PHMSA, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current PSM and RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Environmental Matters

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

We have implemented procedures designed to ensure that governmental environmental approvals for both existing operations and those under construction are updated as circumstances require. Historically, our environmental compliance costs have not had a material adverse effect on our business, results of operations or financial condition; however, there can be no assurance that such costs will not be material in the future. For example, we cannot be certain, however, that identification of presently unidentified conditions, more rigorous enforcement by regulatory agencies, enactment of more stringent environmental laws and regulations or unanticipated events will not arise in the future and give rise to environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

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

We also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, as amended, ("RCRA") and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA hazardous waste requirements at many of our facilities because the minimal quantities of hazardous wastes generated there make us subject to less stringent non-hazardous management standards. From time to time, the EPA has considered or third parties have petitioned the agency on the adoption of stricter handling, storage and disposal standards for nonhazardous wastes, including certain wastes associated with the exploration, development and production of crude oil and natural gas. For example, following the filing of a lawsuit by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the United States District Court for the District of Columbia on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. It is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes such as these examples in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense and, in the case of our oil and natural gas exploration and production customers, could result in increased operating costs for those customers and a corresponding decrease in demand for our processing, transportation and storage services.

We currently own or lease sites that have been used over the years by prior owners and lessees and by us for various activities related to gathering, processing, storage and transmission of natural gas, NGLs, crude oil and refined products. Waste disposal practices within the oil and gas industry have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and wastes have been disposed of or otherwise released on or under various sites during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these releases may have occurred during the ownership or operation of these assets by others, these sites may be subject to CERCLA, RCRA and comparable state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or contamination (including soil and groundwater contamination) or to prevent the migration of contamination.

As of December 31, 2018 and 2017, accruals of $337 million and $372 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover estimated material environmental liabilities including, for example, certain matters assumed in connection with our acquisition of the HPL System, our acquisition of Transwestern, potential environmental liabilities for three sites that were formerly owned by Titan Energy Partners, L.P. or its predecessors, and the predecessor owner's share of certain environmental liabilities of ETC OLP.

The Partnership is subject to extensive and frequently changing federal, tribal, state and local laws and regulations, including those relating to the discharge of materials into the environment or that otherwise relate to the protection of the environment, waste management and the characteristics and composition of fuels. These laws and regulations require environmental assessment and remediation efforts at many of Sunoco, Inc.'s facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $263 million and $284 million at December 31, 2018 and 2017, respectively, which is included in the total accruals above. These legacy sites that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that are no longer operated by Sunoco, Inc., closed and/or sold refineries and other formerly owned sites. In December 2013, a wholly-owned captive insurance company was established for these legacy sites 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. As of December 31, 2018, the captive insurance company held $183 million of cash and investments.

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

Under various environmental laws, including the RCRA, the Partnership has initiated corrective remedial action at certain of its facilities, formerly owned facilities and at certain third-party sites. At the Partnership's major manufacturing facilities, we have typically assumed continued industrial use and a containment/remediation strategy focused on eliminating unacceptable risks to human health or the environment. The remediation accruals for these sites reflect that strategy. Accruals include amounts designed to prevent or mitigate off-site migration and to contain the impact on the facility property, as well as to address known, discrete areas requiring remediation within the plants. Remedial activities include, for example, closure of RCRA waste management units, recovery of hydrocarbons, handling of impacted soil, mitigation of surface water impacts and prevention or mitigation of off-site migration. A change in this approach as a result of changing the intended use of a property or a sale to a third party could result in a comparatively higher cost remediation strategy in the future.

In general, a remediation site or issue is typically evaluated on an individual basis based upon information available for the site or issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (for example, service station sites) in determining the amount of probable loss accrual to be recorded. The estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance allows us the minimum amount of the range to accrue. Accordingly, the low end of the range often represents the amount of loss which has been recorded. The Partnership's consolidated balance sheet reflected $337 million in environmental accruals as of December 31, 2018.

In summary, total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years, but management can provide no assurance that it would be over many years. If changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could materially and adversely 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. And while management does not believe that any such charges would have a material adverse impact on the Partnership's consolidated financial position, it can provide no assurance.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by PCBs, and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2025 is $5 million, which is included in the total environmental accruals mentioned above. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCB contamination. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. Such future costs are not expected to have a material impact on our financial position, results of operations or cash flows, but management can provide no assurance.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, such as our processing plants and compression facilities, expected to produce air emissions or to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. We will incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, our processing plants, pipelines and compression facilities are subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. Historically, our costs for compliance with existing Clean Air Act and comparable state law requirements have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future. The EPA and state agencies are often considering, proposing or finalizing new regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, in October 2015, the EPA published a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the United States counties as either "attainment/unclassifiable" or "unclassifiable." In April 2018, and July 2018, the EPA issued area designations for all areas not addressed in the November 2017 rule. States with moderate or high nonattainment areas must submit state implementation plans to EPA by October 2021. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our customers' operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended, ("Clean Water Act") and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including hydrocarbon-bearing wastes, into state waters and waters of the United States. Pursuant to the Clean Water Act and similar state laws, a National Pollutant Discharge Elimination System, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In May 2015, the EPA issued a final rule that attempts to clarify the federal jurisdictional reach over waters of the United States but this rule has been stayed nationwide by the United States Sixth Circuit Court of Appeals as that appellate court and numerous district courts ponder lawsuits opposing implementation of the rule. In June 2015, the EPA and the United States Army Corps of Engineers ("USACE") published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States, but legal challenges to this rule followed. The 2015 rule was stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases in the matter and, in January 2017, the United States Supreme Court agreed to hear the case. The EPA and USACE proposed a rulemaking in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the Clean Water Act's jurisdiction, and published a proposed rule in November 2017 specifying that the contested May 2015 rule would not take effect until two years after the November 2017 proposed rule was finalized and published in the Federal Register. In January 2018, the United States Supreme Court issued a decision finding that jurisdiction resides with the federal district courts. Also in January 2018, the EPA and USACE finalized a rule that would delay applicability of the rule to two years from the rule's publication in the Federal Register. The EPA and USACE formally proposed a rule revising the definition of "waters of the United States" in December 2018. The proposed definition would substantially reduce the scope of waters that fall within the Clean Water Act's jurisdiction, in part by excluding ephemeral streams. The EPA and the USACE had previously determined that ephemeral streams could potentially qualify as "waters of the United States," which would not be possible under the proposed definition. As a result of these developments, future implementation of the June 2015 rule or any replacement rule is uncertain at this time but to the extent any rule expands the scope of the Clean Water Act's jurisdiction, our operations as well as our exploration and production customers' drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Spills. Our operations can result in the discharge of regulated substances, including NGLs, crude oil or other products. The Clean Water Act, as amended by the federal Oil Pollution Act of 1990, as amended, ("OPA"), and comparable state laws impose restrictions and strict controls regarding the discharge of regulated substances into state waters or waters of the United States. The Clean Water Act and comparable state laws can impose substantial administrative, civil and criminal penalties for non-compliance including spills and other non-authorized discharges. The OPA subjects owners of covered facilities to strict joint and potentially unlimited liability for removal costs and other consequences of a release of oil, where the release is into navigable waters, along shorelines or in the exclusive economic zone of the United States. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require that containment dikes and similar structures be installed to help prevent the impact on navigable waters in the event of a release of oil. The PHMSA, the EPA, or various state regulatory agencies, has approved our oil spill emergency response plans that are to be used in the event of a spill incident.

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

Endangered Species Act. The Endangered Species Act, as amended, restricts activities that may affect endangered or threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may operate in areas that are currently designated as a habitat for endangered or threatened species or where the discovery of previously unidentified endangered species, or the designation of additional species as endangered or threatened may occur in which event such one or more developments could cause us to incur additional costs, to develop habitat conservation plans, to become subject to expansion or operating restrictions, or bans in the affected areas. Moreover, such designation of previously unprotected species as threatened or endangered in areas where our oil and natural gas exploration and production customers operate could cause our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our services.

Climate Change. Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases ("GHGs"). These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted rules under authority of the Clean Air Act that, among other things, establish Potential for Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the Subpart OOOOa standards have been subject to attempts by the EPA to stay portions of those standards, and the agency proposed rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of Subpart OOOOa in its entirety. In September 2018, the EPA proposed amendments to Subpart OOOOa that would reduce the 2016 standards' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 standards and the EPA's attempts to delay the implementation of the rule. This rule, should it remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In August 2017, the United States State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets.

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

Employee Health and Safety. We are subject to the requirements of the federal OSHA and comparable state laws that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. Historically, our costs for OSHA required activities, including general industry standards, recordkeeping 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.

Employees

As of December 31, 2018, ET and its consolidated subsidiaries employed an aggregate of 11,768 employees, 1,434 of which are represented by labor unions. We and our subsidiaries believe that our relations with our employees are satisfactory.

SEC Reporting

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the SEC. From time to time, we may also file registration and related statements pertaining to equity or debt offerings. 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.

ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our structure as a limited partnership, our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. ETO, Panhandle, Sunoco LP and USAC file Annual Reports on Form 10-K that include risk factors that can be reviewed for further information. The risk factors set forth below, and those included in ETO's, Panhandle's, Sunoco LP's and USAC's Annual Reports, are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Inherent in an Investment in Us

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

Our principal source of earnings and cash flow is cash distributions from ETO. In addition, ETO's earnings and cash flows are generated by its subsidiaries, including ETO's investments in Sunoco LP and USAC. Therefore, the amount of distributions we are currently able to make to our Unitholders may fluctuate based on the level of distributions ETO and its subsidiaries, including Sunoco LP and USAC, make to their partners. ETO may not be able to continue to make quarterly distributions at its current level or increase its quarterly distributions in the future. In addition, while we would expect to increase or decrease distributions to our Unitholders if ETO increases or decreases distributions to us, the timing and amount of such increased or decreased distributions, if any, will not necessarily be comparable to the timing and amount of the increase or decrease in distributions made by ETO to us.

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

- interest expense and principal payments on our indebtedness;
- restrictions on distributions contained in any current or future debt agreements;
- our general and administrative expenses;
- expenses of our subsidiaries other than ETO and its subsidiaries, including tax liabilities of our corporate subsidiaries, if any; and
- reserves our general partner believes prudent for us to maintain for the proper conduct of our business or to provide for future distributions.

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

Our cash flow depends primarily on the cash distributions we receive from our partnership interests in ETO, Sunoco LP and USAC, including the incentive distribution rights in Sunoco LP and, therefore, our cash flow is dependent upon the ability of ETO, Sunoco LP and USAC to make distributions in respect of those partnership interests.

We do not have any significant assets other than our partnership interests in ETO. As a result, our cash flow depends on the performance of ETO and its subsidiaries, including Sunoco LP and USAC, and their ability to make cash distributions, which is dependent on the results of operations, cash flows and financial condition of ETO and its subsidiaries, including Sunoco LP and USAC.

The amount of cash that ETO distributes to us each quarter depends upon the amount of cash ETO generates from its operations, which will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas, NGLs, crude oil and refined products transported through ETO's pipelines;
- the level of throughput in processing and treating operations;
- the fees charged and the margins realized by ETO, Sunoco LP and USAC for their services;
- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil prices;
- the weather in their respective operating areas;
- the level of competition from other midstream, transportation and storage and retail marketing companies and other energy providers;
- the level of their respective operating costs and maintenance and integrity capital expenditures;
- the tax profile on any blocker entities treated as corporations for federal income tax purposes that are owned by any of our subsidiaries;
- prevailing economic conditions; and
- the level and results of their respective derivative activities.

In addition, the actual amount of cash that ETO, and its subsidiaries, including Sunoco LP and USAC, will have available for distribution will also depend on other factors, such as:

- the level of capital expenditures they make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- debt service requirements;
- fluctuations in working capital needs;
- their ability to borrow under their respective revolving credit facilities;

- their ability to access capital markets;
- restrictions on distributions contained in their respective debt agreements; and
- the amount, if any, of cash reserves established by the board of directors and their respective general partners in their discretion for the proper conduct of their respective businesses.

ET does not have any control over many of these factors, including the level of cash reserves established by the board of directors. Accordingly, we cannot guarantee that ETO, Sunoco LP and USAC will have sufficient available cash to pay a specific level of cash distributions to their respective partners.

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

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

Our partnership agreement allows us to issue an unlimited number of additional limited partner interests, including securities senior to the Common Units, without the approval of our Unitholders. The issuance of additional Common Units or other equity securities by us will have the following effects:

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

ETO may issue additional preferred equity, and Sunoco LP and USAC may issue additional common units, which may increase the risk that each Partnership will not have sufficient available cash to maintain or increase its per unit distribution level.

The partnership agreements of ETO, Sunoco LP and USAC allow each partnership to issue an unlimited number of additional limited partner interests. The issuance of additional preferred units, common units or other equity securities by each respective partnership will have the following effects:

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

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

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

Unlike the holders of common stock in a corporation, Unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner and will have no right to elect our general partner or the officers or directors of our general partner on an annual or other continuing basis.

Furthermore, if our Unitholders are dissatisfied with the performance of our general partner, they may be unable to remove our general partner. Our general partner may not be removed except, among other things, upon the vote of the holders of at least $66\,^2/_3\%$ of our outstanding units. As of December 31, 2018, our directors and executive officers directly or indirectly own approximately 14% of our outstanding Common Units. It will be particularly difficult for our general partner to be removed without the consent of our directors and executive officers. As a result, the price at which our Common Units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

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

Our general partner may, in its sole discretion, approve the issuance of partnership securities and specify the terms of such partnership securities.

Pursuant to our partnership agreement, our general partner has the ability, in its sole discretion and without the approval of the Unitholders, to approve the issuance of securities by the Partnership at any time and to specify the terms and conditions of such securities. The securities authorized to be issued may be issued in one or more classes or series, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of partnership securities), as shall be determined by our general partner, including:

- the right to share in the Partnership's profits and losses;
- the right to share in the Partnership's distributions;
- the rights upon dissolution and liquidation of the Partnership;
- whether, and the terms upon which, the Partnership may redeem the securities;
- whether the securities will be issued, evidenced by certificates and assigned or transferred; and
- the right, if any, of the security to vote on matters relating to the Partnership, including matters relating to the relative rights, preferences and privileges of such security.

The control of our general partner may be transferred to a third party without Unitholder consent.

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

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

We rely on the services of key personnel of ETO, including the ongoing involvement and continued leadership of Kelcy L. Warren, one of the founders of ETO's midstream business. Mr. Warren has been integral to the success of ETO's midstream and intrastate transportation and storage businesses because of his ability to identify and develop strategic business opportunities. Losing the leadership of Mr. Warren could make it difficult for ETO to identify internal growth projects and accretive acquisitions, which could have a material adverse effect on ETO's ability to increase the cash distributions paid on its partnership interests.

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

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

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

In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner.

To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash available for distribution to our Unitholders and cause the value of our Common Units to decline.

The consolidated debt level and debt agreements of ETO and its subsidiaries, including Sunoco LP and USAC, may limit the distributions we receive from ETO, as well as our future financial and operating flexibility.

ETO's and its subsidiaries' levels of indebtedness affect their operations in several ways, including, among other things:

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

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

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

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

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

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

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

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

Our subsidiaries are not prohibited from competing with us.

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

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

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

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

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

In addition to our exposure to commodity prices, we have significant exposure to changes in interest rates. Approximately $9.76 billion of our consolidated debt as of December 31, 2018 bears interest at variable interest rates and the remainder bears interest at fixed rates. To the extent that we have debt with floating interest rates, our results of operations, cash flows and financial condition could be materially adversely affected by increases in interest rates. We manage a portion of our interest rate exposures by utilizing interest rate swaps.

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

Unitholders may have liability to repay distributions.

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

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to pay distributions to our Unitholders and to service our debt depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. If we are unable to obtain funds from our subsidiaries we may not be able to pay distributions to our Unitholders or to pay interest or principal on our debt when due.

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

As of December 31, 2018, we had approximately $5.52 billion of debt on a stand-alone basis and approximately $46.03 billion of consolidated debt, excluding the debt of our unconsolidated joint ventures. Our level of indebtedness affects our operations in several ways, including, among other things:

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

In order for us to manage our debt levels, we may need to sell assets, issue additional equity securities, reduce the cash distributions we pay to our unitholders or a combination thereof. In the event that we sell assets, the future cash generating capacity of our remaining asset base may be diminished. In the event that we issue additional equity securities, we may need to issue these securities at a time when our common unit price is depressed and therefore we may not receive favorable prices for our common units or favorable prices or terms for other types of equity securities. In the event we reduce cash distributions on our common units, the public trading price of our common units could decline significantly.

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

If at any time our general partner and its affiliates own more than 90% of our outstanding units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, Unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2018, the directors and executive officers of our general partner owned approximately 14% of our Common Units.

Litigation commenced by WMB against ET and its affiliates could cause ET to incur substantial costs, may present material distractions and, if decided adverse to ET, could negatively impact ET's financial position and credit ratings.

WMB filed a complaint against ET and its affiliates in the Delaware Court of Chancery, alleging that the defendants breached the merger agreement between WMB, ET, and several of ET's affiliates. Following a ruling by the Court on June 24, 2016, which allowed for the subsequent termination of the merger agreement by ET on June 29, 2016, WMB filed a notice of appeal to the Supreme Court of Delaware. WMB filed an amended complaint on September 16, 2016 and sought a $410 million termination fee and additional damages of up to $10 billion based on the purported lost value of the merger consideration. These damages claims are based on the alleged breaches of the Merger Agreement, as well as new allegations that the ET Defendants breached an additional representation and warranty in the Merger Agreement. The ET Defendants filed amended counterclaims and affirmative defenses on September 23, 2016 and sought a $1.48 billion termination fee under the Merger Agreement and additional damages caused by WMB's misconduct. These damages claims are based on the alleged breaches of the Merger Agreement, as well as new allegations that WMB breached the Merger Agreement by failing to disclose material information that was required to be disclosed in the Form S-4. On September 29, 2016, WMB filed a motion to dismiss the ET Defendants' amended counterclaims and to strike certain of the ET Defendants' affirmative defenses. On December 1, 2017, the Court issued a Memorandum Opinion granting Williams' motion to dismiss in part and denying it in part. On March 23, 2017, the Delaware Supreme Court affirmed the Court's June 24, 2016 ruling, and as a result, Williams conceded that its $10 billion damages claim is foreclosed, although its $410 million termination fee claim remains pending. Trial is set for May 20, 2019.These lawsuits could result in substantial costs to ET, including litigation costs and settlement costs. ET believes that the time required by the management of ET and its counsel to defend against the allegations made by WMB in the litigation against ET and its affiliates is likely to be substantial and the time required by the officers and employees of LE GP, assuming WMB actively pursues such litigation, is also likely to be substantial. The defense or settlement of any lawsuit or claim that remains unresolved may result in negative media attention, and may adversely affect ET's business, reputation, financial condition, results of operations, cash flows and market price.

Risks Related to Conflicts of Interest

Although we control ETO and its subsidiaries, including Sunoco LP and USAC through our ownership of ETO's general partner, ETO's, Sunoco LP's and USAC's general partners owe fiduciary duties to ETO and ETO's unitholders, Sunoco LP and Sunoco LP's unitholders and USAC and USAC's unitholders respectively, which may conflict with our interests.

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

For example, conflicts of interest with ETO, Sunoco LP and USAC may arise in the following situations:

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

The fiduciary duties of our general partner's officers and directors may conflict with those of ETO's, Sunoco LP's or USAC's respective general partners.

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

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

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

- our general partner is allowed to take into account the interests of parties other than us, including ETO, and its subsidiaries, including Sunoco LP and USAC, and their respective affiliates and any general partners and limited partnerships acquired in the future, in resolving conflicts of interest, which has the effect of limiting its fiduciary duties to us.
- our general partner has limited its liability and reduced its fiduciary duties under the terms of our partnership agreement, while also restricting the remedies available for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, Unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.
- our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution.
- our general partner determines which costs it and its affiliates have incurred are reimbursable by us.

- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.
- our general partner controls the enforcement of obligations owed to us by it and its affiliates.
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

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

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

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our general partner is entitled to make other decisions in "good faith" if it reasonably believes that the decisions are in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by a conflicts committee of the board of directors of our general partner and not involving a vote of Unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us;
- provides that unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty;
- provides that our general partner may resolve any conflicts of interest involving us and our general partner and its affiliates, and any resolution of a conflict of interest by our general partner that is "fair and reasonable" to us will be deemed approved by all partners, including the Unitholders, and will not constitute a breach of the partnership agreement;
- provides that our general partner may, but is not required, in connection with its resolution of a conflict of interest, to seek "special approval" of such resolution by appointing a conflicts committee of the general partner's board of directors composed of two or more independent directors to consider such conflicts of interest and to recommend action to the board of directors, and any resolution of the conflict of interest by the conflicts committee shall be conclusively deemed "fair and reasonable" to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our Unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to unitholders.

Risks Related to the Businesses of our Subsidiaries

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

ETO does not control, and therefore may not be able to cause or prevent certain actions by, certain of its joint ventures.

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

ETO and its subsidiaries, including Sunoco LP and USAC, are exposed to the credit risk of their respective customers and derivative counterparties, and an increase in the nonpayment or nonperformance by their respective customers or derivative counterparties could reduce their respective ability to make distributions to their unitholders, including to us.

The risks of nonpayment or nonperformance by ETO's and its subsidiaries, including Sunoco LP's and USAC's respective customers, are a major concern in their respective businesses. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. ETO and its subsidiaries are subject to risks of loss resulting from nonpayment or nonperformance by their respective customers, especially during the current low commodity price environment impacting many oil and gas producers. As a result, the current commodity price volatility and the tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment or nonperformance by ETO's and its subsidiaries' customers. To the extent one or more of our customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any material nonpayment or nonperformance by our customers or our derivative counterparties could reduce our ability to make distributions to our Unitholders. Any substantial increase in the nonpayment and nonperformance by ETO's or its subsidiaries' customers could have a material adverse effect on ETO's or its subsidiaries' respective results of operations and operating cash flows.

We compete with other businesses in our market with respect to attracting and retaining qualified employees.

Our continued success depends on our ability to attract and retain qualified personnel in all areas of our business. We compete with other businesses in our market with respect to attracting and retaining qualified employees. A tight labor market, increased overtime and a higher full-time employee ratio may cause labor costs to increase. A shortage of qualified employees may require us to enhance wage and benefits packages in order to compete effectively in the hiring and retention of such employees or to hire more expensive temporary employees. No assurance can be given that our labor costs will not increase, or that such increases can be recovered through increased prices charged to customers. We are especially vulnerable to labor shortages in oil and gas drilling areas when energy prices drive higher exploration and production activity.

The use of derivative financial instruments could result in material financial losses by ETO and its subsidiaries.

From time to time, ETO and its subsidiary Sunoco LP have sought to reduce their exposure to fluctuations in commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms and by their trading, marketing and/or system optimization activities. To the extent that either ETO or Sunoco LP hedges its commodity price and interest rate exposures, it foregoes the benefits it would otherwise experience if commodity prices or interest rates were to change favorably. In addition, ETO's and Sunoco LP's derivatives activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the derivative arrangement, the hedge is imperfect, commodity prices move unfavorably related to ETO's or Sunoco LP's physical or financial positions, or internal hedging policies and procedures are not followed.

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

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

The inability to continue to access lands owned by third parties, including tribal lands, could adversely affect ETO's and its subsidiaries' ability to operate and adversely affect their financial results.

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

Further, whether ETO has the power of eminent domain for its pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state. In either case, ETO must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect ETO's business if it were to lose the right to use or occupy the property on which their pipelines are located. For example, following a recent decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. Any loss of rights with respect to ETO's real property, through its inability to renew right-of-way contracts or otherwise, could have a material adverse effect on its business, results of operations, financial condition and ability to make cash distributions.

In addition, Sunoco LP, ETO's subsidiary, does not own all of the land on which its retail service stations are located. Sunoco LP has rental agreements for approximately 38.1% of the company-operated retail service stations where Sunoco LP currently controls the real estate and has rental agreements for certain logistics facilities. As such, Sunoco LP is subject to the possibility of increased costs under rental agreements with landowners, primarily through rental increases and renewals of expired agreements. Sunoco LP is also subject to the risk that such agreements may not be renewed. Additionally, certain facilities and equipment (or parts thereof) used by Sunoco LP are leased from third parties for specific periods. Sunoco LP's inability to renew leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material adverse effect on its financial condition, results of operations and cash flows.

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

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

Consistent with their strategies, managements of ETO, Sunoco LP and USAC may, from time to time, engage in discussions with potential sellers regarding the possible acquisition of additional assets or businesses. Such acquisition efforts may involve ETO, Sunoco LP and USAC management's participation in processes that involve a number of potential buyers, commonly referred to as "auction" processes, as well as situations in which ETO and its subsidiaries believe it is the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot assure that ETO's and its subsidiaries' acquisition efforts will be successful or that any acquisition will be completed on favorable terms.

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

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

As of December 31, 2018, our consolidated balance sheets reflected $4.89 billion of goodwill and $6.00 billion of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' capital and balance sheet leverage as measured by debt to total capitalization.

During the fourth quarter of 2018, the Partnership recognized goodwill impairments of $378 million related to our Northeast operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded. These changes in assumptions reflect delays in the construction of third-party takeaway capacity in the Northeast. During 2018, Sunoco LP recognized a $30 million impairment charge on its contractual rights.

During the fourth quarter of 2017, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments. The goodwill impairments consisted of $262 million in the interstate transportation and storage segment, $79 million in the NGL and refined products transportation and services segment and $452 million in the all other 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 year 2017, Sunoco LP recorded a goodwill impairment charge of $102 million on its retail reporting unit.

During the fourth quarter of 2016, the Partnership performed goodwill impairment tests on our reporting units and recognized goodwill impairments. The goodwill impairments recognized consisted of $638 million related to the interstate transportation and storage segment and $32 million related to the midstream segment. These impairments are primarily due to decreases in projected future revenues and cash flows driven by reduced volumes as a result of overall declining commodity prices and changes in the markets that these assets serve. During the fourth quarter of 2016, Sunoco LP recognized a goodwill impairment of $641 million in its retail reporting unit primarily due to changes in assumptions related to projected future revenues and cash flows from the dates this goodwill was originally recorded. During the fourth quarter of 2016, Sunoco LP also recognized a $32 million impairment on its Laredo Taco brand name intangible asset primarily due to changes in Sunoco LP's construction plan for new-to-industry sites and decreases in sales volume in oil field producing regions where Sunoco LP has operations.

If ETO, and its subsidiaries, including Sunoco LP and USAC do not make acquisitions on economically acceptable terms, their future growth could be limited.

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

ETO and its subsidiaries may be unable to make accretive acquisitions for any of the following reasons, among others:

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

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

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease its liquidity by using a significant portion of its available cash or borrowing capacity to finance acquisitions;
- significantly increase its interest expense or financial leverage if the acquisition is financed with additional debt;
- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which there is no indemnity or the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate its growing business and assets;

- less effectively manage its historical assets, due to the diversion of management's attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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

Integration of assets acquired in past acquisitions or future acquisitions with our existing business will be a complex and time-consuming process. A failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, financial condition, results of operations or cash available for distribution to our unitholders.

The difficulties of integrating past and future acquisitions with our business include, among other things:

- operating a larger combined organization in new geographic areas and new lines of business;
- hiring, training or retaining qualified personnel to manage and operate our growing business and assets;
- integrating management teams and employees into existing operations and establishing effective communication and information exchange with such management teams and employees;
- diversion of management's attention from our existing business;
- assimilation of acquired assets and operations, including additional regulatory programs;
- loss of customers or key employees;
- maintaining an effective system of internal controls in compliance with the Sarbanes-Oxley Act of 2002 as well as other regulatory compliance and corporate governance matters; and
- integrating new technology systems for financial reporting.

If any of these risks or other unanticipated liabilities or costs were to materialize, then desired benefits from past acquisitions and future acquisitions resulting in a negative impact to our future results of operations. In addition, acquired assets may perform at levels below the forecasts used to evaluate their acquisition, due to factors beyond our control. If the acquired assets perform at levels below the forecasts, then our future results of operations could be negatively impacted.

Also, our reviews of proposed business or asset acquisitions are inherently imperfect because it is generally not feasible to perform an in-depth review of each such proposal given time constraints imposed by sellers. Even if performed, a detailed review of assets and businesses may not reveal existing or potential problems, and may not provide sufficient familiarity with such business or assets to fully assess their deficiencies and potential. Inspections may not be performed on every asset, and environmental problems, may not be observable even when an inspection is undertaken.

Legal actions related to the Dakota Access Pipeline could cause an interruption to operations, which could have an adverse effect on our business and results of operations.

On July 25, 2016, the United States 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 also issued easements to allow the pipeline to cross land owned by the USACE adjacent to the Missouri River in two locations. The Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia (the "Court") against the USACE that challenged the legality of the permits issued for the construction of the Dakota Access pipeline and claimed violations of the National Historic Preservation Act ("NHPA"). Dakota Access intervened in the case.

In February 2017, the Department of the Army delivered an easement to Dakota Access allowing the pipeline to cross Lake Oahe. The SRST and Cheyenne River Sioux Tribe ("CRST") (which had intervened in the lawsuit brought by SRST), amended their complaints to incorporate religious freedom and other claims related to treaties and use of government property. The Oglala and Yankton Sioux tribes, and various individual members, filed related lawsuits in opposition to the Dakota Access pipeline. These lawsuits have been consolidated into the action initiated by the SRST.

On June 14, 2017, the Court ruled that the USACE substantially complied with all relevant statutes in connection with the issuance of the permits and easement, but remanded to the USACE three discrete issues for further analysis and explanation of its prior determination under certain of these statutes. On October 11, 2017, the Court ruled that the pipeline could continue to transport crude oil during the pendency of the remand, but requested briefing from the parties as to whether any conditions on the continued operation of the pipeline during this period. On December 4, 2017, the Court determined to impose three conditions on continued operation of the pipeline during the remand process. First, Dakota Access must retain an independent auditor to review its compliance with the conditions and regulations governing its easements and to assess integrity threats to the pipeline. Second, the Court directed Dakota Access to continue its work with the tribes and the USACE to revise and finalize its response planning for the section of the pipeline crossing Lake Oahe. Third, the Court directed Dakota Access to submit bi-monthly reports during the remand period disclosing certain inspection and maintenance information recommended by PHMSA.

While we believe that the pending lawsuits are unlikely to adversely affect the continued operation of the pipeline, we cannot assure this outcome. At this time, we cannot determine when or how these lawsuits will be resolved or the impact they may have on the Dakota Access project.

In addition, lawsuits of this nature could result in interruptions to construction or operations of future projects, delays in completing those projects and/or increased project costs, all of which could have an adverse effect on our business and results of operations.

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

The prices for natural gas, NGLs, crude oil and refined petroleum products reflect market demand that fluctuates with changes in global and United States economic conditions and other factors, including:

- the level of domestic natural gas, NGL, and crude oil production;
- the level of natural gas, NGL, and crude oil imports and exports, including liquefied natural gas;
- actions taken by natural gas and oil producing nations;
- instability or other events affecting natural gas and oil producing nations;
- the impact of weather and other events of nature on the demand for natural gas, NGLs and crude oil;
- the availability of storage, terminal and transportation systems, and refining, processing and treating facilities;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas;
- the cost of capital needed to maintain or increase production levels and to construct and expand facilities
- the impact of energy conservation and fuel efficiency efforts; and
- the extent of governmental regulation, taxation, fees and duties.

In the past, the prices of natural gas, NGLs and crude oil have been extremely volatile, and we expect this volatility to continue.

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

ETO is affected by competition from other midstream, transportation and storage and retail marketing companies.

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

ETO's natural gas and NGL transportation pipelines and storage facilities compete with other interstate and intrastate pipeline companies and storage providers in the transportation and storage of natural gas and NGLs. The principal elements of competition among pipelines are rates, terms of service, access to sources of supply and the flexibility and reliability of service. Natural gas and NGLs also compete with other forms of energy, including electricity, coal, fuel oils and renewable or alternative energy. Competition among fuels and energy supplies is primarily based on price; however, non-price factors, including governmental regulation, environmental impacts, efficiency, ease of use and handling, and the availability of subsidies and tax benefits also affects competitive outcomes.

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

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

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

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

A significant portion of ETO's sales of natural gas are to industrial customers and utilities. As a consequence of the volatility of natural gas prices and increased competition in the industry and other factors, industrial customers, utilities and other gas customers are increasingly reluctant to enter into long-term purchase contracts. Many customers purchase natural gas from more than one supplier and have the ability to change suppliers at any time. Some of these customers also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in natural gas sales markets primarily on the basis of price.

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

Revenue from ETO's NGL transportation systems and refined products storage is also exposed to risks due to fluctuations in demand for transportation and storage service as a result of unfavorable commodity prices, competition from nearby pipelines, and other factors. ETO receives substantially all of their transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to their transportation system. Reduction in demand for natural gas or NGLs due to unfavorable prices or other factors, however, may result lower rates of production under dedicated contracts and lower demand for our services. In addition, ETO's refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers, a portion of its revenue is derived from fungible storage and throughput arrangements, under which ETO's revenue is more dependent upon demand for storage from its customers.

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

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

ETO's midstream facilities and transportation pipelines provide services related to natural gas wells that experience production declines over time, which ETO may not be able to replace with natural gas production from newly drilled wells in the same natural gas basins or in other new natural gas producing areas.

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

A substantial portion of ETO's assets, including its gathering systems and processing and treating plants, are connected to natural gas reserves and wells that experience declining production over time. ETO's gas transportation pipelines are also dependent upon natural gas production in areas served by our gathering systems or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. ETO may not be able to obtain additional contracts for natural gas supplies for its natural gas gathering systems, and may be unable to maintain or increase the levels of natural gas throughput on its transportation pipelines. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity and production of natural gas near our gathering systems or in areas that provide access to its transportation pipelines or markets to which ETO's systems connect. ETO has no control over the level of drilling activity in its areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, ETO has no control over producers or their production and contracting decisions.

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

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

The profitability of certain activities in ETO's natural gas gathering, processing, transportation and storage operations is largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs.

For a portion of the natural gas gathered on ETO's systems, natural gas is purchased from producers at the wellhead and then gathered and delivered to pipelines where it is typically resold various arrangements, including sales at index prices. Generally, the gross margins realized under these arrangements decrease in periods of low natural gas prices. ETO also enters into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which ETO agrees to gather and process natural gas received from producers.

Under percent-of-proceeds arrangements, ETO generally sells the residue gas and NGLs at market prices and remits to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, ETO delivers an agreed upon percentage of the residue gas and NGL volumes to the producer and sells the volumes kept to third parties at market prices. Under these arrangements, ETO's revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on ETO's revenues and results of operations.

Under keep-whole arrangements, ETO generally sells the NGLs produced from its gathering and processing operations at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, ETO must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, gross margins generally decrease when the price of natural gas increases relative to the price of NGLs.

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

ETO also receives fees and retains gas in kind from natural gas transportation and storage customers. The fuel retention fees and the value of gas that ETO retains in kind are directly affected by changes in natural gas prices. Decreases in natural gas prices tend to decrease these fuel retention fees and the value of retained gas.

In addition, ETO receives revenue from its off-gas processing and fractionating system in south Louisiana primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of ETO's off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for off-gas processing and fractionation services and could have an adverse effect on our results of operations.

For ETO's midstream operations, gross margin is generally analyzed based on fee-based margin (which includes revenues from processing fee arrangements) and non-fee based margin (which includes gross margin earned on percent-of-proceeds and keep-whole arrangements). For the years ended December 31, 2018, 2017 and 2016, gross margin from ETO's midstream operations totaled $2.38 billion, $2.18 billion, and $1.80 billion, respectively, of which fee-based revenues constituted 76%, 77% and 86%, respectively, and non-fee based margin constituted 24%, 23% and 14%, respectively. The amount of gross margin earned by ETO's midstream operations from fee-based and non-fee based arrangements (individually and as a percentage of total revenues) will be impacted by the volumes associated with both types of arrangements, as well as commodity prices; therefore, the dollar amounts and the relative magnitude of gross margin from fee-based and non-fee based arrangements in future periods may be significantly different from results reported in previous periods.

ETO's revenues depend on its customers' ability to use ETO's pipelines and third-party pipelines over which we have no control.

ETO's natural gas transportation, storage and NGL businesses depend, in part, on their customers' ability to obtain access to pipelines to deliver gas to and receive gas from ETO. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on our pipelines or third-party pipelines due to testing, line repair, reduced operating pressures, or other causes or adverse change in terms and conditions of service could have a material adverse effect on ETO's ability, and the ability of its customers, to transport natural gas to and from ETO's pipelines and facilities and a corresponding material adverse effect on its transportation and storage revenues. In addition, the rates charged by interconnected pipelines for transportation to and from ETO's facilities affect the utilization and value of ETO's storage services. Significant changes in the rates charged by those pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on storage revenues.

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

If ETO does not continue to construct new pipelines, its future growth could be limited.

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

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

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

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

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

ETO depends on certain key producers for a significant portion of its supplies of natural gas. The loss of, or reduction in, any of these key producers could adversely affect ETO's business and operating results.

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

ETO depends on key customers to transport natural gas through its pipelines.

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

ETO's contract compression operations depend on particular suppliers and are vulnerable to parts and equipment shortages and price increases, which could have a negative impact on results of operations.

The substantial majority of the components for ETO's natural gas compression equipment are supplied by Caterpillar Inc., Cummins Inc. and Arrow Engine Company for engines, Air-X-Changers and Alfa Laval (US) for coolers, and Ariel Corporation, GE Oil & Gas Gemini products and Arrow Engine Company for compressor frames and cylinders. ETO's reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. ETO also relies primarily on four vendors, A G Equipment Company, Alegacy Equipment, LLC, Standard Equipment Corp. and Genis Holdings LLC, to package and assemble its compression units. ETO does not have long-term contracts with these suppliers or packagers, and a partial or complete loss of any of these sources could have a negative impact on its results of operations and could damage its customer relationships. Some of these suppliers manufacture the components ETO purchases in a single facility, and any damage to that facility could lead to significant delays in delivery of completed compression units to ETO.

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

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

An interruption of supply of crude oil to ETO's facilities could materially and adversely affect our results of operations and revenues.

While ETO is well positioned to transport and receive crude oil by pipeline, marine transport and trucks, rail transportation also serves as a critical link in the supply of domestic crude oil production to United States refiners, especially for crude oil from regions such as the Bakken that are not sourced near pipelines or waterways that connect to all of the major United States refining centers. Federal regulators have issued a safety advisory warning that Bakken crude oil may be more volatile than many other North American crude oils and reinforcing the requirement to properly test, characterize, classify, and, if applicable, sufficiently degasify hazardous materials prior to and during transportation. The domestic crude oil received by our facilities, especially from the Bakken region, may be transported by railroad. If the ability to transport crude oil by rail is disrupted because of accidents, weather interruptions, governmental regulation, congestion on rail lines, terrorism, other third-party action or casualty or other events, then ETO could experience an interruption of supply or delivery or an increased cost of receiving crude oil, and could experience a decline in volumes received. Recent railcar accidents in Quebec, Alabama, North Dakota, Pennsylvania and Virginia, in each case involving trains carrying crude oil from the Bakken region, have led to increased legislative and regulatory scrutiny over the safety of transporting crude oil by rail. In 2015, the DOT, through the PHMSA, issued a rule implementing new rail car standards and railroad operating procedures. Changing operating practices, as well as new regulations on tank car standards and shipper classifications, could increase the time required to move crude oil from production areas of facilities, increase the cost of rail transportation, and decrease the efficiency of transportation of crude oil by rail, any of which could materially reduce the volume of crude oil received by rail and adversely affect our financial condition, results of operations, and cash flows.

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

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

A significant decrease in demand for motor fuel, including increased consumer preference for alternative motor fuels or improvements in fuel efficiency, in the areas Sunoco LP, ETO's subsidiary, serves would reduce their ability to make distributions to unitholders.

Sales of refined motor fuels account for approximately 97% of Sunoco LP's total revenues and 71% of continuing operations gross profit. A significant decrease in demand for motor fuel in the areas Sunoco LP serves could significantly reduce revenues and their ability to make distributions to unitholders. Sunoco LP revenues are dependent on various trends, such as trends in commercial truck traffic, travel and tourism in their areas of operation, and these trends can change. Regulatory action, including government imposed fuel efficiency standards, may also affect demand for motor fuel. Because certain of Sunoco LP's operating costs and expenses are fixed and do not vary with the volumes of motor fuel distributed, their costs and expenses might not decrease ratably or at all should they experience such a reduction. As a result, Sunoco LP may experience declines in their profit margin if fuel distribution volumes decrease.

Any technological advancements, regulatory changes or changes in consumer preferences causing a significant shift toward alternative motor fuels could reduce demand for the conventional petroleum based motor fuels Sunoco LP currently sells. Additionally, a shift toward electric, hydrogen, natural gas or other alternative-power vehicles could fundamentally change customers' shopping habits or lead to new forms of fueling destinations or new competitive pressures.

New technologies have been developed and governmental mandates have been implemented to improve fuel efficiency, which may result in decreased demand for petroleum-based fuel. Any of these outcomes could result in fewer visits to Sunoco LP's convenience stores or independently operated commission agents and dealer locations, a reduction in demand from their wholesale customers, decreases in both fuel and merchandise sales revenue, or reduced profit margins, any of which could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to unitholders.

The industries in which Sunoco LP, ETO's subsidiary, operates are subject to seasonal trends, which may cause our operating costs to fluctuate, affecting our cash flow.

Sunoco LP relies in part on customer travel and spending patterns, and may experience more demand for gasoline in the late spring and summer months than during the fall and winter. Travel, recreation and construction are typically higher in these months in the geographic areas in which Sunoco LP or its commission agents and dealers operate, increasing the demand for motor fuel that they sell and distribute. Therefore, Sunoco LP's revenues and cash flows are typically higher in the second and third quarters of our fiscal year. As a result, Sunoco LP's results from operations may vary widely from period to period, affecting Sunoco LP's cash flow.

Sunoco LP's financial condition and results of operations are influenced by changes in the prices of motor fuel, which may adversely impact margins, customers' financial condition and the availability of trade credit.

Sunoco LP's operating results are influenced by prices for motor fuel. General economic and political conditions, acts of war or terrorism and instability in oil producing regions, particularly in the Middle East and South America, could significantly impact crude oil supplies and petroleum costs. Significant increases or high volatility in petroleum costs could impact consumer demand for motor fuel and convenience merchandise. Such volatility makes it difficult to predict the impact that future petroleum costs fluctuations may have on Sunoco LP's operating results and financial condition. Sunoco LP is subject to dealer tank wagon pricing structures at certain locations further contributing to margin volatility. A significant change in any of these factors could materially impact both wholesale and retail fuel margins, the volume of motor fuel distributed or sold at retail, and overall customer traffic, each of which in turn could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to unitholders.

Significant increases in wholesale motor fuel prices could impact Sunoco LP as some of their customers may have insufficient credit to purchase motor fuel from us at their historical volumes. Higher prices for motor fuel may also reduce access to trade credit support or cause it to become more expensive.

The dangers inherent in the storage and transportation of motor fuel could cause disruptions in Sunoco LP's operations and could expose them to potentially significant losses, costs or liabilities.

Sunoco LP stores motor fuel in underground and aboveground storage tanks. Sunoco LP transports the majority of its motor fuel in its own trucks, instead of by third-party carriers. Sunoco LP's operations are subject to significant hazards and risks inherent in transporting and storing motor fuel. These hazards and risks include, but are not limited to, traffic accidents, fires, explosions, spills, discharges, and other releases, any of which could result in distribution difficulties and disruptions, environmental pollution, governmentally-imposed fines or clean-up obligations, personal injury or wrongful death claims, and other damage to its properties and the properties of others. Any such event not covered by Sunoco LP's insurance could have a material adverse effect on its business, financial condition, results of operations and cash available for distribution to unitholders.

Sunoco LP's fuel storage terminals are subject to operational and business risks which may adversely affect their financial condition, results of operations, cash flows and ability to make distributions to unitholders.

Sunoco LP's fuel storage terminals are subject to operational and business risks, the most significant of which include the following:

- the inability to renew a ground lease for certain of their fuel storage terminals on similar terms or at all;
- the dependence on third parties to supply their fuel storage terminals;
- outages at their fuel storage terminals or interrupted operations due to weather-related or other natural causes;
- the threat that the nation's terminal infrastructure may be a future target of terrorist organizations;
- the volatility in the prices of the products stored at their fuel storage terminals and the resulting fluctuations in demand for storage services;
- the effects of a sustained recession or other adverse economic conditions;
- the possibility of federal and/or state regulations that may discourage their customers from storing gasoline, diesel fuel, ethanol and jet fuel at their fuel storage terminals or reduce the demand by consumers for petroleum products;
- competition from other fuel storage terminals that are able to supply their customers with comparable storage capacity at lower prices; and
- climate change legislation or regulations that restrict emissions of GHGs could result in increased operating and capital costs and reduced demand for our storage services.

The occurrence of any of the above situations, amongst others, may affect operations at their fuel storage terminals and may adversely affect Sunoco LP's business, financial condition, results of operations, cash flows and ability to make distributions to unitholders.

Negative events or developments associated with Sunoco LP's branded suppliers could have an adverse impact on its revenues.

Sunoco LP believes that the success of its operations is dependent, in part, on the continuing favorable reputation, market value, and name recognition associated with the motor fuel brands sold at Sunoco LP's convenience stores and at stores operated by its independent, branded dealers and commission agents. Erosion of the value of those brands could have an adverse impact on the volumes of motor fuel Sunoco LP distributes, which in turn could have a material adverse effect on its business, financial condition, results of operations and ability to make distributions to its unitholders.

The wholesale motor fuel distribution industry and convenience store industry are characterized by intense competition and fragmentation and impacted by new entrants. Failure to effectively compete could result in lower margins.

The market for distribution of wholesale motor fuel is highly competitive and fragmented, which results in narrow margins. Sunoco LP has numerous competitors, some of which may have significantly greater resources and name recognition than it does. Sunoco

LP relies on its ability to provide value-added, reliable services and to control its operating costs in order to maintain our margins and competitive position. If Sunoco LP fails to maintain the quality of its services, certain of its customers could choose alternative distribution sources and margins could decrease. While major integrated oil companies have generally continued to divest retail sites and the corresponding wholesale distribution to such sites, such major oil companies could shift from this strategy and decide to distribute their own products in direct competition with Sunoco LP, or large customers could attempt to buy directly from the major oil companies. The occurrence of any of these events could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to unitholders.

The geographic areas in which Sunoco LP operates and supplies independently operated commission agent and dealer locations are highly competitive and marked by ease of entry and constant change in the number and type of retailers offering products and services of the type we and our independently operated commission agents and dealers sell in stores. Sunoco LP competes with other convenience store chains, independently owned convenience stores, motor fuel stations, supermarkets, drugstores, discount stores, dollar stores, club stores, mass merchants and local restaurants. Over the past two decades, several non-traditional retailers, such as supermarkets, hypermarkets, club stores and mass merchants, have impacted the convenience store industry, particularly in the geographic areas in which Sunoco LP operates, by entering the motor fuel retail business. These non-traditional motor fuel retailers have captured a significant share of the motor fuels market, and Sunoco LP expects their market share will continue to grow.

In some of Sunoco LP's markets, its competitors have been in existence longer and have greater financial, marketing, and other resources than they or their independently operated commission agents and dealers do. As a result, Sunoco LP's competitors may be able to better respond to changes in the economy and new opportunities within the industry. To remain competitive, Sunoco LP must constantly analyze consumer preferences and competitors' offerings and prices to ensure that they offer a selection of convenience products and services at competitive prices to meet consumer demand. Sunoco LP must also maintain and upgrade our customer service levels, facilities and locations to remain competitive and attract customer traffic to our stores. Sunoco LP may not be able to compete successfully against current and future competitors, and competitive pressures faced by Sunoco LP could have a material adverse effect on its business, results of operations and cash available for distribution to unitholders.

Sunoco LP currently depends on a limited number of principal suppliers in each of its operating areas for a substantial portion of its merchandise inventory and its products and ingredients for its food service facilities. A disruption in supply or a change in either relationship could have a material adverse effect on its business.

Sunoco LP currently depends on a limited number of principal suppliers in each of its operating areas for a substantial portion of its merchandise inventory and its products and ingredients for its food service facilities. If any of Sunoco LP's principal suppliers elect not to renew their contracts, Sunoco LP may be unable to replace the volume of merchandise inventory and products and ingredients currently purchased from them on similar terms or at all in those operating areas. Further, a disruption in supply or a significant change in Sunoco LP's relationship with any of these suppliers could have a material adverse effect on Sunoco LP's business, financial condition and results of operations and cash available for distribution to unitholders.

Sunoco LP may be subject to adverse publicity resulting from concerns over food quality, product safety, health or other negative events or developments that could cause consumers to avoid its retail locations or independently operated commission agent or dealer locations.

Sunoco LP may be the subject of complaints or litigation arising from food-related illness or product safety which could have a negative impact on its business. Negative publicity, regardless of whether the allegations are valid, concerning food quality, food safety or other health concerns, food service facilities, employee relations or other matters related to its operations may materially adversely affect demand for its food and other products and could result in a decrease in customer traffic to its retail stores or independently operated commission agent or dealer locations.

It is critical to Sunoco LP's reputation that they maintain a consistent level of high quality at their food service facilities and other franchise or fast food offerings. Health concerns, poor food quality or operating issues stemming from one store or a limited number of stores could materially and adversely affect the operating results of some or all of their stores and harm the company-owned brands, continuing favorable reputation, market value and name recognition.

USAC's customers may choose to vertically integrate their operations by purchasing and operating their own compression fleet, increasing the number of compression units they currently own or using alternative technologies for enhancing crude oil production.

USAC's customers that are significant producers, processors, gatherers and transporters of natural gas and crude oil may choose to vertically integrate their operations by purchasing and operating their own compression fleets in lieu of using USAC's compression services. The historical availability of attractive financing terms from financial institutions and equipment manufacturers facilitates this possibility by making the purchase of individual compression units increasingly affordable to USAC's customers. In addition, there are many technologies available for the artificial enhancement of crude oil production, and USAC's customers may elect to use these alternative technologies instead of the gas lift compression services USAC provides. Such vertical integration, increases in vertical integration or use of alternative technologies could result in decreased demand for USAC's compression services, which may have a material adverse effect on its business, results of operations, financial condition and reduce its cash available for distribution.

A significant portion of USAC's services are provided to customers on a month-to-month basis, and USAC cannot be sure that such customers will continue to utilize its services.

USAC's contracts typically have an initial term of between six months and five years, depending on the application and location of the compression unit. After the expiration of the initial term, the contract continues on a month-to-month or longer basis until terminated by USAC or USAC's customers upon notice as provided for in the applicable contract. As of December 31, 2018, approximately 47% of USAC's compression services on a revenue basis were provided on a month-to-month basis to customers who continue to utilize its services following expiration of the primary term of their contracts. These customers can generally terminate their month-to-month compression services contracts on 30-days' written notice. If a significant number of these customers were to terminate their month-to-month services, or attempt to renegotiate their month-to-month contracts at substantially lower rates, it could have a material adverse effect on USAC's business, results of operations, financial condition and cash available for distribution.

USAC's Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of its common units.

USAC's Preferred Units rank senior to all of its other classes or series of equity securities with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for its common units, or could make it more difficult for USAC to sell its common units in the future.

In addition, distributions on USAC's Preferred Units accrue and are cumulative, at the rate of 9.75% per annum on the original issue price, which amounts to a quarterly distribution of $24.375 per Preferred Unit. If USAC does not pay the required distributions on its Preferred Units, USAC will be unable to pay distributions on its common units. Additionally, because distributions on USAC's Preferred Units are cumulative, USAC will have to pay all unpaid accumulated distributions on the Preferred Units before USAC can pay any distributions on its common units. Also, because distributions on USAC's common units are not cumulative, if USAC does not pay distributions on its common units with respect to any quarter, USAC's common unitholders will not be entitled to receive distributions covering any prior periods if USAC later recommences paying distributions on its common units.

USAC's Preferred Units are convertible into common units by the holders of USAC's Preferred Units or by USAC in certain circumstances. USAC's obligation to pay distributions on USAC's Preferred Units, or on the common units issued following the conversion of USAC's Preferred Units, could impact USAC's liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general Partnership purposes. USAC's obligations to the holders of USAC's Preferred Units could also limit its ability to obtain additional financing or increase its borrowing costs, which could have an adverse effect on its financial condition.

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

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of ETO's interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs.

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

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

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

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

The ability of interstate pipelines held in tax-pass-through entities, like ETO, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before the FERC and the courts for a number of years. Effective January 2018, the 2017 Tax and Jobs Act (the "Tax Act") changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related proposals, the FERC addressed treatment of federal income tax allowances in regulated entity rates. The FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost of service rates. The FERC issued the Revised Policy Statement in response to a remand from the United States Court of Appeals for the District of Columbia Circuit in United Airlines v. FERC, in which the court determined that the FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not "double recover" its taxes under the current policy by both including an income-tax allowance in its cost of service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, the FERC issued an order denying requests for rehearing and clarification of its Revised Policy Statement because it is a non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs.

Included in the March 15, 2018 proposals is a Notice of Proposed Rulemaking ("NOPR") proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, the FERC issued a Final Rule (Order No. 849) adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information and to make an election on how to treat its existing rates. The Final Rule suggests that this information will allow the FERC and other stakeholders to evaluate the impacts of the Tax Act and the Revised Policy Statement on each individual pipeline's rates. The Final Rule also requires that each FERC regulated natural gas pipeline select one of four options: file a limited Natural Gas Act ("NGA") Section 4 filing reducing its rates only as required related to the Tax Act and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. For the limited NGA Section 4 option, the FERC clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Trunkline, ETC Tiger Pipeline, LLC and Panhandle filed their respective FERC Form No. 501-Gs on October 11, 2018. FEP, Lake Charles LNG and certain other operating subsidiaries filed their respective FERC Form No. 501-Gs on or about November 8, 2018. Rover, FGT, Transwestern and MEP filed their respective FERC Form No. 501-Gs on or about December 6, 2018. Because our existing jurisdictional rates were established based on a higher corporate tax rate, FERC or our shippers may challenge these rates in the future, and the resulting new rate may be lower than the rates we currently charge. For example, the FERC has recently initiated reviews of Panhandle's and Southwest Gas Storage Company's existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged are just and reasonable. These reviews will require the filing of a cost and revenue study prior to the FERC issuing a decision.

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

Transportation provided on ETO's common carrier interstate crude oil, NGL and refined products pipelines is subject to rate regulation by the FERC, which requires that tariff rates for transportation on these pipelines be just and reasonable and not unduly discriminatory. If ETO proposes new or changed rates, the FERC or interested persons may challenge those rates and the FERC is authorized to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the proposed rate is unjust or unreasonable, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The primary ratemaking methodology used by the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. The FERC's ratemaking methodologies may limit ETO's ability to set rates based on its costs or may delay the use of rates that reflect increased costs. In October 2016, FERC issued an Advance Notice of Proposed Rulemaking seeking comment on a number of proposals, including: (i) whether the Commission should deny any increase in a rate ceiling or annual index-based rate increase if a pipeline's revenues exceed total costs by 15 percent for the prior two years; (ii) a new percentage comparison test that would deny a proposed increase to a pipeline's rate or ceiling level greater than 5 percent above the barrel-mile cost changes; and (iii) a requirement that all pipelines file indexed ceiling levels annually, with the ceiling levels subject to challenge and restricting the pipeline's ability to carry forward the full indexed increase to a future period. The comment period with respect to the proposed rules ended March 17, 2017. FERC has not yet taken any further action on the proposed rule. If the FERC's indexing methodology changes, the new methodology could materially and adversely affect ETO's financial condition, results of operations or cash flows.

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

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

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

ETO's midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects ETO's business and the market for its products. The rates, terms and conditions of service for the interstate services ETO provides in its intrastate gas pipelines and gas storage are subject to FERC regulation under Section 311 of the NGPA. ETO's HPL System, East Texas pipeline, Oasis pipeline and ET Fuel System provide such services. Under Section 311, rates charged for transportation and storage must be fair and equitable. Amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service, set forth in the pipeline's statement of operating conditions, are subject to FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than ETO's costs of service, its cash flow would be negatively affected.

ETO's midstream and intrastate gas and oil transportation pipelines and its intrastate gas storage operations are subject to state regulation. All of the states in which we operate midstream assets, intrastate pipelines or intrastate storage facilities have adopted some form of complaint-based regulation, which allow producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to the fairness of rates and terms of access. The states in which ETO operates have ratable take statutes, which generally require gatherers to take, without undue discrimination, production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Should a complaint be filed in any of these states or should regulation become more active, ETO's businesses may be adversely affected.

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

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

Certain of ETO's assets may become subject to regulation.

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

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. Lone Star's NGL pipeline transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGL transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. In 2013, Lone Star's NGL pipeline also commenced the interstate transportation of NGLs, which is subject to FERC's jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. Both intrastate and interstate NGL transportation services must be provided in a manner that is just, reasonable, and non-discriminatory. The tariff rates established for interstate services were based on a negotiated agreement; however, if FERC's ratemaking methodologies were imposed, they may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. In addition, the rates, terms and conditions for shipments of crude oil, petroleum products and NGLs on our pipelines are subject to regulation by FERC if the NGLs are transported in interstate or foreign commerce, whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all crude oil, petroleum products and NGLs on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

In addition, if any of our pipelines were found to have provided services or otherwise operated in violation of the NGA, NGPA, or ICA, this could result in the imposition of administrative and criminal remedies and civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

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

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

These regulations require operators of covered pipelines to:

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

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. Any changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, in January 2017, PHMSA issued a final rule for hazardous liquid pipelines that significantly expands the reach of certain PHMSA integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a HCA. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register is uncertain given the recent change in Presidential administrations. In a second example, in April 2016, PHMSA published a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; requiring gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressure ("MOAP"); and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements and also require consideration of seismicity in evaluating threats to pipelines. In 2018, PHMSA announced its intention to divide the original proposed rulemaking into three parts and issue three separate final rulemakings in

2019. PHMSA indicated that the first of the three final rulemakings could come as early as March 2019, although that timing is likely to be impacted by the federal government shutdown. The changes adopted or proposed by these rulemakings or made in future legal requirements could have a material adverse effect on ETO's results of operations and costs of transportation services.

***Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation*.**

The NGPSA and HLPSA were amended by the 2011 Pipeline Safety Act. Among other things, the 2011 Pipeline Safety Act increased the penalties for safety violations and directed the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm that the material strength of certain pipelines are above 30% of specified minimum yield strength, and operator verification of records confirming the MAOP of certain interstate natural gas transmission pipelines. In November 2018, PHMSA issued a final rule increasing the maximum administrative fines for safety violations, with maximum civil penalties set at $213,268 per day, with a maximum of $2,132,679 for a series of violations. In June 2016, the 2016 Pipeline Safety Act was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities, which are expected in 2019. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of natural gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment. In 2018, PHMSA announced its intention to divide the original proposed rulemaking into three parts and issue three separate final rulemakings in 2019. PHMSA indicated that the first of the three final rulemakings could come as early as March 2019, although that timing is likely to be impacted by the federal government shutdown from December 2018 through January 2019. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act, as further amended by the 2016 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto, could require ETO to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in ETO incurring increased operating costs that could be significant and have a material adverse effect on ETO's results of operations or financial condition.

ETO's business involves the generation, handling and disposal of hazardous substances, hydrocarbons and wastes, which activities are subject to environmental and worker health and safety laws and regulations that may cause ETO to incur significant costs and liabilities.

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

ETO may incur substantial environmental costs and liabilities because of the underlying risk arising out of its operations. Although we have established financial reserves for our estimated environmental remediation liabilities, additional contamination or conditions may be discovered, resulting in increased remediation costs, liabilities or natural resource damages that could substantially increase our costs for site remediation projects. Accordingly, we cannot assure you that our current reserves are adequate to cover all future liabilities, even for currently known contamination.

Changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, emission standards, or storage, transport, disposal or remediation requirements could have a material adverse effect on ETO's operations or financial position. For example, in October 2015, the EPA published a final rule under the Clean

Air Act, lowering the NAAQS for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the United States counties as either "attainment/unclassifiable" or "unclassifiable." The EPA finalized its non-attainment designations for the remaining areas of the United States not addressed under the November 2017 final rule in April and July of 2018. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to ETO's customers' operations. Compliance with this final rule or any other new regulations could, among other things, require installation of new emission controls on some of ETO's equipment, result in longer permitting timelines or new restrictions or prohibitions with respect to permits or projects, and significantly increase its capital expenditures and operating costs, which could adversely impact its business. Historically, ETO has been able to satisfy the more stringent nitrogen oxide emission reduction requirements that affect its compressor units in ozone non-attainment areas at reasonable cost, but there is no assurance that it will not incur material costs in the future to meet the new, more stringent ozone standard.

Regulations under the Clean Water Act, OPA and state laws impose regulatory burdens on terminal operations. Spill prevention control and countermeasure requirements of federal and state laws require containment to mitigate or prevent contamination of waters in the event of a refined product overflow, rupture, or leak from above-ground pipelines and storage tanks. The Clean Water Act also requires ETO to maintain spill prevention control and countermeasure plans at ETO's terminal facilities with above-ground storage tanks and pipelines. In addition, OPA requires that most fuel transport and storage companies maintain and update various oil spill prevention and oil spill contingency plans. Facilities that are adjacent to water require the engagement of Federally Certified Oil Spill Response Organizations ("OSRO"s) to be available to respond to a spill on water from above-ground storage tanks or pipelines.

Transportation and storage of refined products over and adjacent to water involves risk and potentially subjects ETO to strict, joint, and potentially unlimited liability for removal costs and other consequences of an oil spill where the spill is into navigable waters, along shorelines or in the exclusive economic zone of the United States. In the event of an oil spill into navigable waters, substantial liabilities could be imposed upon ETO. The Clean Water Act imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters, with the potential of substantial liability for the violation of permits or permitting requirements.

Terminal operations and associated facilities are subject to the Clean Air Act as well as comparable state and local statutes. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions, and operating permits may be required for sources that are already constructed. If regulations become more stringent, additional emission control technologies

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

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

Along with other refiners, manufacturers and sellers of gasoline, ETC Sunoco Holdings LLC (formerly Sunoco, Inc.) is a defendant in numerous lawsuits that allege methyl tertiary butyl ether ("MTBE") contamination in groundwater. Plaintiffs, who include water purveyors and municipalities responsible for supplying drinking water and private well owners, are seeking compensatory damages (and in some cases injunctive relief, punitive damages and attorneys' fees) for claims relating to the alleged manufacture and distribution of a defective product (MTBE-containing gasoline) that contaminates groundwater, and general allegations of product liability, nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. There has been insufficient information developed about the plaintiffs' legal theories or the facts that would be relevant to an analysis of the ultimate liability to ETC Sunoco Holdings LLC. An adverse determination of liability related to these allegations or other product liability claims against ETC Sunoco Holdings LLC could have a material adverse effect on our business or results of operations.

Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the services we provide.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted rules under authority of the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the Subpart OOOOa standards have been subject to attempts by the EPA to stay portions of those standards, and the agency proposed rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of Subpart OOOOa in its entirety. In September 2018, the EPA proposed amendments to Subpart OOOOa that would reduce the 2016 standards' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 standards and the EPA's attempts to delay the implementation of the rule. This rule, should it remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to ETO's operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect ETO's business. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In August 2017, the United States State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on ETO's business, financial condition, demand for its services, results of operations, and cash flows. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on ETO's assets.

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder could have an adverse effect on our ability to use derivative instruments to mitigate the risks of changes in commodity prices and interest rates and other risks associated with our business.

Provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") and rules adopted by the Commodity Futures Trading Commission (the "CFTC"), the SEC and other prudential regulators establish federal regulation of the physical and financial derivatives, including over-the-counter derivatives market and entities, such as us, participating in that market. While most of these regulations are already in effect, the implementation process is still ongoing and the CFTC continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, any new regulations or modifications to existing regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability and/or liquidity of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. Any of these consequences could have a material adverse effect on our financial condition, results of operations and cash available for distribution to our unitholders.

The CFTC has re-proposed speculative position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, although certain bona fide hedging transactions would be exempt from these position limits provided that various conditions are satisfied. The CFTC has also finalized a related aggregation rule that requires market participants to aggregate their positions with certain other persons under common ownership and control, unless an exemption applies, for purposes of determining whether the position limits have been exceeded. If adopted, the revised position limits rule and its finalized companion rule on aggregation may create additional implementation or operational exposure. In addition to the CFTC federal speculative position limit regime, designated contract markets ("DCMs") also maintain speculative position limit and accountability regimes with respect to contracts listed on their platform as well as aggregation requirements similar to the CFTC's final aggregation rule. Any speculative position limit regime, whether imposed at the federal-level or at the DCM-level may impose added operating costs to monitor compliance with such position limit levels, addressing accountability level concerns and maintaining appropriate exemptions, if applicable.

The Dodd-Frank Act requires that certain classes of swaps be cleared on a derivatives clearing organization and traded on a DCM or other regulated exchange, unless exempt from such clearing and trading requirements, which could result in the application of certain margin requirements imposed by derivatives clearing organizations and their members. The CFTC and prudential regulators have also adopted mandatory margin requirements for uncleared swaps entered into between swap dealers and certain other counterparties. We currently qualify for and rely upon an end-user exception from such clearing and margin requirements for the swaps we enter into to hedge our commercial risks. However, the application of the mandatory clearing and trade execution requirements and the uncleared swaps margin requirements to other market participants, such as swap dealers, may adversely affect the cost and availability of the swaps that we use for hedging.

In addition to the Dodd-Frank Act, the European Union and other foreign regulators have adopted and are implementing local reforms generally comparable with the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with non-U.S. counterparties and may make transactions involving cross-border swaps more expensive and burdensome. Additionally, the lack of regulatory equivalency across jurisdictions may increase compliance costs and make it more difficult to satisfy our regulatory obligations.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail ETO's operations and otherwise materially adversely affect its cash flow.

Some of ETO's operations involve risks of personal injury, property damage and environmental damage, which could curtail its operations and otherwise materially adversely affect its cash flow. For example, natural gas pipeline and other facilities operate at high pressures. Virtually all of ETO's operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

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

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

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

The United States government has issued warnings that energy assets, including the nation's pipeline infrastructure, may be the future target of terrorist organizations. Some of our facilities are subject to standards and procedures required by the Chemical Facility Anti-Terrorism Standards. We believe we are in compliance with all material requirements; however, such compliance may not prevent a terrorist attack from causing material damage to our facilities or pipelines. Any such terrorist attack on ETO's or Sunoco LP's facilities or pipelines, those of their customers, or in some cases, those of other pipelines could have a material adverse effect on ETO's or Sunoco LP's business, financial condition and results of operations.

Additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration and oil spill-response plans, and other related restrictions arising after the Deepwater Horizon incident in the Gulf of Mexico may have a material adverse effect on our business, financial condition, or results of operations.

In recent years, the federal Bureau of Ocean Energy Management ("BOEM") and the federal Bureau of Safety and Environmental Enforcement ("BSEE"), each agencies of the United States Department of the Interior, have imposed more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these more stringent regulatory requirements and with existing environmental and oil spill regulations, together with any uncertainties or inconsistencies in decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts.

In addition, new regulatory initiatives may be adopted or enforced by the BOEM or the BSEE in the future that could result in additional costs, delays, restrictions, or obligations with respect to oil and natural gas exploration and production operations conducted offshore by certain of ETO's customers. For example, in April 2016, the BOEM published a proposed rule that would update existing air-emissions requirements relating to offshore oil and natural-gas activity on federal Outer Continental Shelf waters. However, in May 2017, Order 3350 was issued by the Department of the Interior Secretary Ryan Zinke, directing the BOEM to reconsider a number of regulatory initiatives governing oil and gas exploration in offshore waters, including, among other things, a cessation of all activities to promulgate the April 2016 proposed rulemaking ("Order 3350"). In an unrelated legal initiative, BOEM issued a Notice to Lessees and Operators ("NTL #2016-N01") that became effective in September 2016 and imposes more stringent requirements relating to the provision of financial assurance to satisfy decommissioning obligations. Together with a recent re-assessment by BSEE in 2016 in how it determines the amount of financial assurance required, the revised BOEM-administered offshore financial assurance program that is currently being implemented is expected to result in increased amounts of financial assurance being required of operators on the OCS, which amounts may be significant. However, as directed under Order 3350, the BOEM has delayed implementation of NTL #2016-N01 so that it may reconsider this regulatory initiative and, currently, this NTL's implementation timeline has been extended indefinitely beyond June 30, 2017, except in certain circumstances where there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities. The April 2016 proposed rule and NTL #2016-N01, should they be finalized and/or implemented, as well as any new rules, regulations, or legal initiatives could delay or disrupt our customers operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, limit activities in certain areas, or cause our customers' to incur penalties, or shut-in production or lease cancellation. Also, if material spill events were to occur in the future, the United States or other countries could elect to issue directives to temporarily cease drilling activities offshore and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development. The overall costs imposed on ETO's customers to implement and complete any such spill response activities or any decommissioning obligations could exceed estimated accruals, insurance limits, or supplemental bonding amounts, which could result in the incurrence of additional costs to complete. We cannot predict with any certainty the full impact of any new laws or regulations on ETO's customers' drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations. The occurrence of any one or more of these developments could result in decreased demand for ETO's services, which could have a material adverse effect on its business as well as its financial position, results of operation and liquidity.

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

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

In addition, our butane blending services are reliant upon gasoline vapor pressure specifications. Significant changes in such specifications could reduce butane blending opportunities, which would affect our ability to market our butane blending service licenses and which would ultimately affect our ability to recover the costs incurred to acquire and integrate our butane blending assets.

Our business could be affected adversely by union disputes and strikes or work stoppages by Panhandle's and Sunoco LP's unionized employees.

As of December 31, 2018, approximately 12% of our workforce is covered by a number of collective bargaining agreements with various terms and dates of expiration. There can be no assurances that Panhandle or Sunoco LP will not experience a work stoppage in the future as a result of labor disagreements. Any work stoppage could, depending on the affected operations and the length of the work stoppage, have a material adverse effect on our business, financial position, results of operations or cash flows.

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

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

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

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

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

The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results.

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

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

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

The liquefaction project is dependent upon securing long-term contractual arrangements for the off-take of LNG on terms sufficient to support the financial viability of the project.

LCL, our wholly-owned subsidiary, is in the process of developing a liquefaction project at the site of our existing regasification facility in Lake Charles, Louisiana. The project development agreement previously entered into in September 2013 with BG Group plc, a subsidiary of Shell, related to this project expired in February 2017. On June 28, 2017, LCL signed a memorandum of understanding with Korea Gas Corporation and Shell to study the feasibility of a joint development of the Lake Charles liquefaction project. The project would utilize existing dock and storage facilities owned by us located on the Lake Charles site. The parties' determination as to the feasibility of the project will be particularly dependent upon the prospects for securing long-term contractual arrangements for the off-take of LNG which in turn will be dependent upon supply and demand factors affecting the price of LNG in foreign markets. The financial viability of the project will also be dependent upon a number of other factors, including the expected cost to construct the liquefaction facility, the terms and conditions of the financing for the construction of the liquefaction facility, the cost of the natural gas supply, the costs to transport natural gas to the liquefaction facility, the costs to operate the liquefaction facility and the costs to transport LNG from the liquefaction facility to customers in foreign markets (particularly Europe and Asia). Some of these costs fluctuate based on a variety of factors, including supply and demand factors affecting the price of natural gas in the United States, supply and demand factors affecting the costs for construction services for large infrastructure projects in the United States, and general economic conditions, there can be no assurance that the parties will determine to proceed to develop this project.

The construction of the liquefaction project remains subject to further approvals and some approvals may be subject to further conditions, review and/or revocation.

While LCL has received authorization from the DOE to export LNG to non-FTA countries, the non-FTA authorization is subject to review, and the DOE may impose additional approval and permit requirements in the future or revoke the non-FTA authorization should the DOE conclude that such export authorization is inconsistent with the public interest. The FERC order (issued December 17, 2015) authorizing LCL to site, construct and operate the liquefaction project contains a condition requiring all phases of the liquefaction project to be completed and in-service within five years of the date of the order. The order also requires the modifications to our Trunkline pipeline facilities that connect to our Lake Charles facility be complete by December 17, 2019 and additionally requires execution of a transportation contract for natural gas supply to the liquefaction facility prior to the initiation of construction of the liquefaction facility. Although we intend to file an application with the FERC to seek an extension of these completion dates for the project, the FERC may not grant this extension.

Sunoco LP is subject to federal laws related to the Renewable Fuel Standard.

New laws, new interpretations of existing laws, increased governmental enforcement of existing laws or other developments could require us to make additional capital expenditures or incur additional liabilities. For example, certain independent refiners have initiated discussions with the EPA to change the way the Renewable Fuel Standard ("RFS") is administered in an attempt to shift the burden of compliance from refiners and importers to blenders and distributors. Under the RFS, which requires an annually increasing amount of biofuels to be blended into the fuels used by U.S. drivers, refiners/importers are obligated to obtain renewable identification numbers ("RINS") either by blending biofuel into gasoline or through purchase in the open market. If the obligation was shifted from the importer/refiner to the blender/distributor, the Partnership would potentially have to utilize the RINS it obtains through its blending activities to satisfy a new obligation and would be unable to sell RINS to other obligated parties, which may cause an impact on the fuel margins associated with Sunoco LP's sale of gasoline.

The occurrence of any of the events described above could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to its unitholders.

Sunoco LP is subject to federal, state and local laws and regulations that govern the product quality specifications of refined petroleum products it purchases, stores, transports, and sells to its distribution customers.

Various federal, state, and local government agencies have the authority to prescribe specific product quality specifications for certain commodities, including commodities that Sunoco LP distributes. Changes in product quality specifications, such as reduced sulfur content in refined petroleum products, or other more stringent requirements for fuels, could reduce Sunoco LP's ability to procure product, require it to incur additional handling costs and/or require the expenditure of capital. If Sunoco LP is unable to procure product or recover these costs through increased selling price, it may not be able to meet its financial obligations. Failure to comply with these regulations could result in substantial penalties for Sunoco LP.

The NYSE does not require a publicly traded partnership like us to comply with certain corporate governance requirements.

Because we are a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to stockholders of corporations that are subject to all of the corporate governance requirements of the applicable stock exchange.

Tax Risks to Unitholders

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

The anticipated after-tax economic benefit of an investment in our Common Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this matter. The value of our investments in ETO and its subsidiaries, including Sunoco LP and USAC, depend largely on ETO, Sunoco LP and USAC being treated as partnerships for federal income tax purposes. Despite the fact that we, ETO, Sunoco LP and USAC are each a limited partnership under Delaware law, we would each be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we, ETO, Sunoco LP and USAC satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us, ETO, Sunoco LP or USAC to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we, ETO, Sunoco LP or USAC were treated as a corporation, we would pay federal income tax at the corporate tax rate and we would likely pay additional state income taxes at varying rates. Distributions to Unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to Unitholders. Because a tax would then be imposed upon us as a corporation, our cash available for distribution to Unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of our Common Units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our Unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or to additional taxation as an entity for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present United States federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing United States federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for United States federal income tax purposes.

However, any modification to the United States federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for United States federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

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

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

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our Unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each Unitholder and former Unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our Unitholders and former Unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current Unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such Unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our Unitholders might be substantially reduced.

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

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

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions to our unitholders in excess of the total net taxable income the unitholder was allocated for a unit, which decreased their tax basis in that unit, will, in effect, become taxable income to our unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be “unrelated business taxable income” and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our units.

Non-United States Unitholders will be subject to United States taxes and withholding with respect to their income and gain from owning our units.

Non-United States unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a United States trade or business (“effectively connected income”). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be “effectively connected” with a United States trade or business. As a result, distributions to a Non-United States unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-United States unitholder who sells or otherwise disposes of a unit will also be subject to United States federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-United States unitholder’s sale or exchange of an interest in a partnership that is engaged in a United States trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-United States unitholders should consult a tax advisor before investing in our units.

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

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

We treat each purchaser of Common Units as having the same tax benefits without regard to the actual Common Units purchased. The IRS may challenge this treatment, which could result in a Unitholder owing more tax and may adversely affect the value of the Common Units.

Because we cannot match transferors and transferees of Common Units and because of other reasons, we have adopted depreciation, depletion and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our Unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of Common Units and could have a negative impact on the value of our Common Units or result in audit adjustments to tax returns of our Unitholders. Moreover, because we have subsidiaries that are organized as C corporations for federal income tax purposes owns units in us, a successful IRS challenge could result in this subsidiary having a greater tax liability than we anticipate and, therefore, reduce the cash available for distribution to our partnership and, in turn, to our Unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge aspects of our proration method, and if successful, we would be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

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

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a Unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the Unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining Unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

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

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

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

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

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. Although the interest limitation does not apply to certain regulated pipeline businesses, application of the interest limitation to tiered businesses like ours that hold interests in regulated and unregulated businesses is not clear. Pending further guidance specific to this issue, we have not yet determined the impact the limitation could have on our unitholders' ability to deduct our interest expense, but it is possible that our unitholders' interest expense deduction will be limited.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in "Item 1. Business." In addition, we own office buildings for our executive offices in Dallas, Texas and office buildings in Newton Square, Pennsylvania; Houston, San Antonio, and Austin, Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

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

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

ITEM 3. LEGAL PROCEEDINGS

Sunoco, Inc. and Sunoco, Inc. (R&M) (now known as Sunoco (R&M), LLC) (collectively, "Sunoco") are defendants in lawsuits alleging MTBE contamination of groundwater. The plaintiffs, state-level governmental entities, assert product liability, nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices claims. The plaintiffs 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, 2018, Sunoco is a defendant in six cases, including one case each initiated by the States of Maryland, Vermont and Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants Energy Transfer Partners, L.P., ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals, L.P.

In late July 2018, the Court in the Vermont matter denied the State of Vermont's motion to amend its complaint to add specific allegations regarding some of the sites the court previously dismissed. The State of Vermont and the defendants reached a settlement in principle to resolve the remaining statewide Vermont Case in September 2018. The parties are in the process of finalizing settlement documents.

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. 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 such adverse determination occurs, but such an adverse determination likely would not have a material adverse effect on the Partnership's consolidated financial position.

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, EPA issued a Finding of Violation ("FOV") to TRC and, on September 30, 2013, EPA issued a Notice of Violation ("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 to the 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.

In October 2016, the PHMSA issued a Notice of Probable Violation ("NOPVs") and a Proposed Compliance Order ("PCO") related to ETO's West Texas Gulf pipeline in connection with repairs being carried out on the pipeline and other administrative and procedural findings. The proposed penalty is in excess of $100,000. The case went to hearing in March 2017 and remains open with PHMSA. ETO 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 ETO's Permian Express 2 pipeline system in Texas. The proposed penalties are in excess of $100,000. The case went to hearing in November 2016 and remains open with PHMSA. ETO 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 to our West Texas Gulf pipeline in connection with inspection and maintenance activities related to a 2013 incident on our crude oil pipeline near Wortham, Texas. The proposed penalties are in excess of $100,000. The case went to hearing in March 2017. PHMSA Southwest Region has issued its post-hearing recommendations to PHMSA headquarters. The recommendations included a provision for alteration of the number of instances of violation for one NOPV. All remaining NOPVs are unchanged. There was a minor reduction in the civil penalty expected due to a reduction in the number of instances of violation for one NOPV, and the Proposed Compliance Order was fully withdrawn. We do not expect there to be a material impact to our results of operations, cash flows, or financial position.

In August 2017, the PHMSA issued a NOPV and a PCO in connection with alleged violations on ETO's Nederland to Kilgore pipeline in Texas. The case remains open with PHMSA and the proposed penalties are in excess of $100,000. ETO does not expect there to be a material impact to its results of operations, cash flows or financial position.

In December 2016, we received multiple Notice of Violations ("NOVs") from the Delaware County Regional Water Quality Control Authority ("DELCORA") in connection with a discharge at our Marcus Hook Industrial Complex ("MHIC") in July 2016. We also entered in a Consent Order and Agreement from the Pennsylvania Department of Environmental Protection ("PADEP") related to our tank inspection plan at MHIC. These actions propose penalties in excess of $100,000, and we are currently in discussions with the PADEP and DELCORA to resolve these matters. The timing or outcome of these matters 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.

The Ohio Environmental Protection Agency ("Ohio EPA") has alleged that various environmental violations have occurred during construction of the Rover pipeline project. The alleged violations include inadvertent returns of drilling muds and fluids at horizontal directional drilling ("HDD") locations in Ohio that affected waters of the State, storm water control violations, hydrostatic permit violations involving the alleged discharge of effluent with greater levels of pollutants than the permits allowed and allegedly not properly sampling or monitoring effluent for required parameters or reporting those alleged violations, and engaging in construction activities without an effective water quality certification. Although Rover has successfully completed clean-up mitigation for the alleged violations to Ohio EPA's satisfaction, the Ohio EPA has proposed penalties and restitution of approximately $2.6 million in connection with the alleged violations and is seeking certain injunctive relief. The Ohio Attorney General filed a complaint in the Court of Common Pleas of Stark County, Ohio to obtain these remedies and that case remains pending and is in the early stages. Rover and other defendants filed several motions to dismiss and Ohio EPA filed a motion in opposition. The State's opposition to those motions was filed on October 12, 2018. Rover and other defendants filed their replies on November 2, 2018. The court has not yet ruled on the motion. The State requested oral argument on the motion, but no argument has been scheduled to date. 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.

In addition, on May 10, 2017, the FERC prohibited Rover from conducting HDD activities at 27 sites in Ohio. On July 31, 2017, the FERC issued an independent third party assessment of what led to the release at the Tuscarawas River site and what Rover can do to prevent reoccurrence once the HDD suspension is lifted. Rover has implemented the suggestions in the assessment and additional voluntary protocols. The FERC has authorized Rover to resume HDD activities at all sites.

In late 2016, FERC Enforcement Staff began a non-public investigation of Rover's demolition of the Stoneman House, a potential historic structure, in connection with Rover's application for permission to construct a new interstate natural gas pipeline and related facilities. Rover and ETO are cooperating with the investigation. In March and April 2017, Enforcement Staff provided Rover its non-public preliminary findings regarding its investigation. The company disagrees with those findings and intends to vigorously defend against any potential penalty. Given the stage of the proceeding, and the non-public nature of the preliminary findings and investigation, ETO is unable at this time to provide an assessment of the potential outcome or range of potential liability, if any.

On July 25, 2017, the Pennsylvania Environmental Hearing Board ("EHB") issued an order to SPLP to cease HDD activities in Pennsylvania related to the Mariner East 2 project. On August 1, 2017 the EHB lifted the order as to two drill locations. On August 3, 2017, the EHB lifted the order as to 14 additional locations. The EHB issued the order in response to a complaint filed by environmental groups against SPLP and the PADEP. The EHB Judge encouraged the parties to pursue a settlement with respect to the remaining HDD locations and facilitated a settlement meeting. On August 7, 2017 a final settlement was reached. A stipulated order has been submitted to the EHB Judge with respect to the settlement. The settlement agreement requires that SPLP reevaluate the design parameters of approximately 26 drills on the Mariner East 2 project and approximately 43 drills on the Mariner East 2X project. The settlement agreement also provides a defined framework for approval by PADEP for these drills to proceed after reevaluation. Additionally, the settlement agreement requires modifications to several of the HDD plans that are part of the PADEP permits. Those modifications have been completed and agreed to by the parties. SPLP continued throughout 2018 to complete HDDs on the Mariner East 2 project using the reevaluation process outlined in the EHB order. On July 31, 2018, the environmental groups voluntarily dismissed their action in the EHB after reaching a settlement with the PADEP that did not involve SPLP.

In addition, on June 27, 2017 and July 25, 2017, the PADEP entered into a Consent Order and Agreement with SPLP regarding inadvertent returns of drilling fluids at three HDD locations in Pennsylvania related to the Mariner East 2 project. Those agreements require SPLP to cease HDD activities at those three locations until PADEP reauthorizes such activities and to submit a corrective action plan for agency review and approval. SPLP has fulfilled the requirements of those agreements and has been authorized by PADEP to resume drilling the locations.

On January 3, 2018, PADEP issued an Administrative Order to SPLP directing that work on the Mariner East 2 and 2X pipelines be stopped. The Administrative Order detailed alleged violations of the permits issued by PADEP in February 2017, during the construction of the project. SPLP began working with PADEP representatives immediately after the Administrative Order was issued to resolve the compliance issues. Those compliance issues could not be fully resolved by the deadline to appeal the Administrative Order, so SPLP took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, SPLP entered into a Consent Order and Agreement with PADEP that (i) withdraws the Administrative Order; (ii) establishes requirements for compliance with permits on a going forward basis; (iii) resolves the non-compliance alleged in the Administrative Order; and (iv) conditions restart of work on an agreement by SPLP to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, SPLP admits to the factual allegations, but does not admit to the conclusions of law that were made by PADEP. PADEP also found in the Consent Order and Agreement that SPLP had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. SPLP concurrently filed a request to the Pennsylvania Environmental Hearing Board to discontinue the appeal of the Administrative Order. That request was granted on February 8, 2018.

On January 18, 2018, PHMSA issued a NOPV and a Proposed Civil Penalty in connection with alleged violations on our East Boston jet fuel pipeline in Boston, MA. We have paid the civil penalties of $121,000. The case was closed in October 2018.

Energy Transfer Company Field Services received NOV REG-0569-1701 on June 6, 2017 for emission events that occurred January 1, 2017 through April 16, 2017 at the Jal 3 gas plant. On September 11, 2017, the New Mexico Environmental Department sent ETO a settlement offer to resolve the NOV for a penalty of $596,278. Negotiations for this settlement offer are ongoing.

Energy Transfer Company Field Services received NOV REG-0569-1701 on June 6, 2017 for emission events that occurred January 1, 2017 through April 16, 2017 at the Jal 3 gas plant. On September 11, 2017, the New Mexico Environmental Department sent ETO a settlement offer to resolve the NOV for a penalty of $596,278. Negotiations for this settlement offer are ongoing.

Energy Transfer Company Field Services received NOV REG-0569-1702 on December 8, 2017 for emission events that occurred April 17, 2017 through September 23, 2017 at the Jal 3 gas plant. On January 31, 2018, ETO received a settlement offer to resolve the NOV for a penalty of $602,138. Negotiations for this settlement offer are ongoing.

Energy Transfer Company Field Services received NOV REG-0569-1801 on February 13, 2018 for emission events that occurred September 25, 2017 through December 29, 2017 at the Jal 3 gas plant. On June, 11, 2018, the New Mexico Environmental Department sent ETO a settlement offer to resolve the NOV for a penalty of $268,213. Negotiations for this settlement offer are ongoing.

On June 29, 2018, Luminant Energy Company, LLC (“Luminant”) filed informal and formal complaints against Energy Transfer Fuel, LP (“ETF”), with the Railroad Commission of Texas (“TRRC”). Luminant’s complaints allege that absent an agreement between Luminant and ETF regarding the rate to be charged for bundled transportation and storage service, ETF must file a statement of intent with the TRRC to change the rate charged to Luminant for this service. ETF filed a response to Luminant’s informal complaint on July 16, 2018. ETF filed a response and motion to dismiss Luminant’s formal complaint on July 23, 2018. On August 16, 2018, a Commission Administrative Law Judge (“ALJ”) granted ETF’s motion to dismiss Luminant’s claims relating to unlawful abandonment and discrimination. The ALJ denied ETF’s motion to dismiss Luminant’s claims regarding the rate charged for service and the procedural process applicable to rate changes. Luminant appealed the decision. The appeal was denied by operation of law on October 1, 2018. A mediation of the informal complaint filed by Luminant was held on September 17, 2018 and no decision was reached. The parties executed new agreements for transportation and storage services effective December 1, 2018. Luminant has withdrawn its formal and informal complaints against ETF, (unopposed by ETF), as of January 2, 2019.

In June 2018, ETC Northeast Pipeline LLC (“ETC Northeast”) entered into a Consent Order and Agreement with the PADEP, pursuant to which ETC Northeast agreed to pay $150,242 to the PADEP to settle various statutory and common law claims relating to soil discharge into, and erosion of the stream bed of, Raccoon Creek in Center Township, Pennsylvania during construction of the Revolution Pipeline. ETC Northeast has paid the settlement amount and continues to monitor the construction site and work with the landowner to resolve any remaining issues related to the restoration of the construction site.

Energy Transfer Company Field Services received NOV REG-0569-1802 from the New Mexico Environmental Department on July 25, 2018 for emission events that occurred January 1, 2018 through April 30, 2018 at the Jal 3 gas plant. On September 25, 2018, ETO received a settlement offer to resolve the NOV for a penalty of $1,151,499. Negotiations for this settlement offer are ongoing.

On September 17, 2018, William D. Warner ("Plaintiff"), a purported Energy Transfer Partners, L.P. unitholder, filed a putative class action asserting violations of various provisions of the Securities Exchange Act of 1934 and various rules promulgated thereunder in connection with the Energy Transfer Merger against ETO, Kelcy L. Warren, Michael K. Grimm, Marshall S. McCrea, Matthew S. Ramsey, David K. Skidmore, and W. Brett Smith ("Defendants"). Plaintiff specifically alleged that the proxy statement related to the Energy Transfer Merger omitted and/or misrepresented material information. On December 17, 2018, Plaintiff voluntarily dismissed his lawsuit.

Energy Transfer Field Company Services received NOV REG-0569-1803 from the New Mexico Environmental Department on November 8, 2018 for emission events that occurred May 1, 2018 through August 31, 2018 at the Jal 3 gas plant. On December 28, 2018, ETO received a settlement offer to resolve the NOV for a penalty of $1,405,652. Negotiations for this settlement offer are ongoing.

On September 10, 2018, a pipeline release and fire occurred on the Revolution Pipeline in the vicinity of Ivy Lane located in Center Township, Beaver County, Pennsylvania. There were no injuries but there were evacuations of local residents as a precautionary measure. The Pennsylvania Department of Environmental Protection ("PADEP") and the Pennsylvania Public Utility Commission ("PUC") are investigating the incident. On October 29, 2018, PADEP issued a Compliance Order requiring our subsidiary, ETC Northeast, to cease all earth disturbance activities at the site (except as necessary to repair and maintain existing Best Management Practices ("BMPs") and temporarily stabilize disturbed areas), implement and/or maintain the Erosion and Sediment BMPs at the site, stake the limit of disturbance, identify and report all areas of non-compliance, and submit an updated Erosion and Sediment Control Plan, a Temporary Stabilization Plan, and an updated Post Construction Stormwater Management Plan. The scope of the Compliance Order has been expanded to include the disclosure to PADEP of alleged violations of environmental permits with respect to various construction and post-construction activities and restoration obligations along the 42-mile route of the Revolution line. ETC Northeast filed an appeal of the Compliance Order with the Pennsylvania Environmental Hearing Board.

On February 8, 2019, PADEP filed a Petition to Enforce the Compliance Order with Pennsylvania's Commonwealth Court. The Court issued an Order on February 14, 2019 requiring the submission of an answer to the Petition on or before March 12, 2019, and scheduling a hearing on the Petition for March 26, 2019. PADEP has also and issued a Permit Hold on any requests for approvals/permits or permit amendments made by us or any of our subsidiaries for any projects in Pennsylvania pursuant to the state's water laws. We continue to work through these issues with PADEP.

In January 2019, we received notice from the DOJ on behalf of the EPA that an enforcement action was being pursued under the Clean Water Act for an estimated 450 barrel crude oil release from the pipeline operated by SPLP and owned by Mid-Valley. The release purportedly occurred in October 2014 on a nature preserve located in Hamilton County, Ohio, near Cincinnati, Ohio. After discovery and notification of the release, SPLP conducted substantial emergency response and remedial efforts in three phases and that work is substantially complete. DOJ, on behalf of United States Department of Interior Fish and Wildlife, and the Ohio Attorney General, on behalf of Ohio EPA, along with technical representatives from those agencies have also been discussing natural resource damage assessment claims. The timing and 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.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the environmental proceedings listed above were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report environmental governmental proceedings if we reasonably believe that such proceedings will result in monetary sanctions in excess of $100,000.

For a description of other legal proceedings, see Note 11 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Parent Company

Description of Units

As of February 15, 2019, there were approximately 470,000 registered common unitholders, which includes common units held in street name. Common units represent limited partner interest in us that entitle the holders to the rights and privileges specified in the Parent Company's Third Amended and Restated Agreement of Limited Partnership, as amended to date (the "Partnership Agreement").

As of December 31, 2018, limited partners own an aggregate 99.9% limited partner interest in us. Our General Partner owns an aggregate 0.1% General Partner interest in us. Our common units are registered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and are listed for trading on the NYSE under the ticker symbol "ET." Each holder of a common unit is entitled to one vote per unit on all matters presented to the limited partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all common units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our Partnership Agreement. The common units are entitled to distributions of Available Cash as described below under "Cash Distribution Policy."

ET Series A Convertible Preferred Units

On March 8, 2016, the Partnership completed a private offering of 329.3 million Series A Convertible Preferred Units representing limited partner interests in the Partnership (the "Convertible Units") to certain common unitholders ("Electing Unitholders") who elected to participate in a plan to forgo a portion of their future potential cash distributions on common units participating in the plan for a period of up to nine fiscal quarters, commencing with distributions for the fiscal quarter ended March 31, 2016, and reinvest those distributions in the Convertible Units. At the end of the plan period, May 18, 2018, the Convertible Units automatically converted into common units based on the Conversion Value (as defined and described below) of the Convertible Units and a conversion rate of $6.56.

The conversion value of each Convertible Unit (the "Conversion Value") on the closing date of the offering was zero. The Conversion Value increased each quarter in an amount equal to $0.285, which is the per unit amount of the cash distribution paid with respect to ET common units for the quarter ended December 31, 2015 (the "Conversion Value Cap"), less the cash distribution actually paid with respect to each Convertible Unit or common unit, as applicable, for such quarter. Any cash distributions in excess of $0.285 per ET common unit, and any Extraordinary Distributions, made with respect to any quarter during the plan period were disregarded for purposes of calculating the Conversion Value. The Conversion Value was reflected in the carrying amount of the Convertible Units until the conversion into common units at the end of the plan period. The Convertible Units had $450 million and $519 million carrying values as of December 31, 2017 and March 31, 2018, respectively. In May 2018, the Partnership converted its 329.3 million Series A Convertible Preferred Units into approximately 79.1 million ET common units in accordance with the terms of the partnership agreement.

ET Class A Units

In connection with the Energy Transfer Merger, the Partnership issued 647,745,099 Class A units ("ET Class A Units") representing limited partner interests in the Partnership to the General Partner. The number of ET Class A Units issued allows the General Partner and its affiliates to retain a voting interest in the Partnership that is identical to their voting interest in the Partnership prior to the completion of the Energy Transfer Merger. The ET Class A Units are entitled to vote together with the Partnership's common units, as a single class, except as required by law. Additionally, ET's partnership agreement provides that, under certain circumstances, upon the issuance by the Partnership of additional common units or any securities that have voting rights that are pari passu with the Partnership common units, the Partnership will issue to any holder of ET Class A Units additional ET Class A Units such that the holder maintains a voting interest in the Partnership that is identical to its voting interest in the Partnership prior to such issuance of common units. The ET Class A Units are not entitled to distributions and otherwise have no economic attributes.

Cash Distribution Policy

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

Definition of Available Cash. Available Cash is defined in the Parent Company's Partnership Agreement and generally means, with respect to any calendar quarter, all cash on hand at the end of such quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:

- provide for the proper conduct of its business;
- comply with applicable law and/or debt instrument or other agreement; and
- provide funds for distributions to unitholders and its General Partner in respect of any one or more of the next four quarters.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

Securities Authorized for Issuance Under Equity Compensation Plans

For information on the securities authorized for issuance under ET's equity compensation plans, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters."

ITEM 6. SELECTED FINANCIAL DATA

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

	Years Ended December 31,				
	2018	2017	2016	2015	2014
Statement of Operations Data:					
Total revenues	$ 54,087	$ 40,523	$ 31,792	$ 36,096	$ 54,435
Operating income	5,348	2,721	1,851	2,287	2,389
Income from continuing operations	3,630	2,543	462	1,023	1,014
Income (loss) from discontinued operations	(265)	(177)	(462)	38	60
Net Income	3,365	2,366	—	1,061	1,074
Basic income from continuing operations per limited partner unit	1.17	0.86	0.95	1.11	0.57
Diluted income from continuing operations per limited partner unit	1.16	0.84	0.93	1.11	0.57
Basic income (loss) from discontinued operations per limited partner unit	(0.01)	(0.01)	(0.01)	—	0.01
Diluted income (loss) from discontinued operations per limited partner unit	(0.01)	(0.01)	(0.01)	—	0.01
Cash distribution per common unit	1.22	1.17	1.14	1.08	0.80
Balance Sheet Data (at period end):					
Assets held for sale	—	3,313	3,588	3,681	3,372
Total assets[(1)]	88,246	86,246	78,925	71,144	64,266
Liabilities associated with assets held for sale	—	75	48	42	47
Long-term debt, less current maturities	43,373	43,671	42,608	36,837	29,477
Total equity	30,850	29,980	22,431	23,553	22,301

(1) Includes assets held for sale

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

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

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

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

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ET" mean Energy Transfer LP and its consolidated subsidiaries, which include ETO, ETP GP, ETP LLC, Panhandle, Sunoco LP and Lake Charles LNG. References to the "Parent Company" mean Energy Transfer LP on a stand-alone basis.

OVERVIEW

Energy Transfer LP directly and indirectly owns equity interests in ETO, Sunoco LP and USAC, all of which are limited partnerships engaged in diversified energy-related services. Sunoco LP and USAC have publicly traded common units.

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETO. ETO's earnings and cash flows are generated by its subsidiaries, including ETO's investments in Sunoco LP and USAC. The amount of cash that ETO, Sunoco LP and USAC distribute to their respective partners, including the Parent Company, each quarter is based on earnings from their respective business activities and the amount of available cash, as discussed below.

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

General

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

Our reportable segments are as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;
- crude oil transportation and services;
- investment in Sunoco LP;
- investment in USAC; and
- all other.

The general partner of ETO has separate operating management and boards of directors. We control ETO through our owner ship of its respective general partners.

Recent Developments

ET Series A Convertible Preferred Units

In May 2018, the Partnership converted its 329.3 million Series A Convertible Preferred Units into approximately 79.1 million ET common units in accordance with the terms of ET's partnership agreement.

ET Class A Units

In connection with the Energy Transfer Merger, the Partnership issued 647,745,099 Class A units ("ET Class A Units") representing limited partner interests in the Partnership to the General Partner. The number of ET Class A Units issued allows the General Partner and its affiliates to retain a voting interest in the Partnership that is identical to their voting interest in the Partnership prior to the completion of the Merger.

ETO 2019 Senior Notes Offering and Redemption

In January 2019, ETO issued $750 million aggregate principal amount of 4.50% senior notes due 2024, $1.50 billion aggregate principal amount of 5.25% senior notes due 2029 and $1.75 billion aggregate principal amount of 6.25% senior notes due 2049. The $3.96 billion net proceeds from the offering were used to repay in full ET's outstanding senior secured term loan, to redeem outstanding senior notes, to repay a portion of the borrowings under the Partnership's revolving credit facility and for general partnership purposes.

Energy Transfer Merger

In October 2018, we completed the merger of ETO with a wholly-owned subsidiary of ET in a unit-for-unit exchange (the "Energy Transfer Merger"). In connection with the transaction, ETO unitholders (other than ET and its subsidiaries) received 1.28 common units of ET for each common unit of ETO they owned.

Immediately prior to the closing of the Energy Transfer Merger, the following also occurred:

- the IDRs in ETO were converted into 1,168,205,710 ETO common units; and
- the general partner interest in ETO was converted to a non-economic general partner interest and ETO issued 18,448,341 ETO common units to ETP GP.

Immediately prior to the closing of the Energy Transfer Merger discussed in "Item 8. Financial Statements and Supplementary Data," ET contributed the following to ETO:

- 2,263,158 common units representing limited partner interests in Sunoco LP to ETO in exchange for 2,874,275 ETO common units;
- 100 percent of the limited liability company interests in Sunoco GP LLC, the sole general partner of Sunoco LP, and all of the IDRs in Sunoco LP, to ETO in exchange for 42,812,389 ETO common units;
- 12,466,912 common units representing limited partner interests in USAC and 100 percent of the limited liability company interests in USA Compression GP, LLC, the general partner of USAC, to ETO in exchange for 16,134,903 ETO common units; and
- a 100 percent limited liability company interest in Lake Charles LNG and a 60 percent limited liability company interest in each of Energy Transfer LNG Export, LLC, ET Crude Oil Terminals, LLC and ETC Illinois LLC (collectively, "Lake Charles LNG and Other") to ETO in exchange for 37,557,815 ETO common units.

Permian Gulf Coast Pipeline Joint Venture

In September 2018, ETO, Magellan Midstream Partners, L.P., MPLX LP and Delek US Holdings, Inc. announced that they have received sufficient commitments to proceed with plans to construct a new 30-inch diameter common carrier pipeline, the Permian Gulf Coast ("PGC") pipeline, to transport crude oil from the Permian Basin to the Texas Gulf Coast region. The 600-mile PGC pipeline system is expected to be operational in mid-2020 with multiple Texas origins. The pipeline system will have the strategic capability to transport crude oil to ETO's Nederland, Texas terminal for ultimate delivery through its distribution system. The project is subject to receipt of customary regulatory and Board approvals of the respective entities, and the transaction structure for this project has not been finalized.

ETO Series D Preferred Units Issuance

In July 2018, ETO issued 17.8 million of its 7.625% Series D Preferred Units (liquidation preference of $25 per unit) resulting in total gross proceeds of $445 million. The proceeds were used to repay amounts outstanding under ETO's revolving credit facility and for general partnership purposes.

ETO 2018 Senior Notes Offering and Redemption

In June 2018, ETO issued $500 million aggregate principal amount of 4.20% senior notes due 2023, $1.00 billion aggregate principal amount of 4.95% senior notes due 2028, $500 million aggregate principal amount of 5.80% senior notes due 2038 and

$1.00 billion aggregate principal amount of 6.00% senior notes due 2048. The $2.96 billion net proceeds from the offering were used to redeem outstanding senior notes, to repay borrowings outstanding under ETO's revolving credit facility and for general partnership purposes.

Old Ocean Joint Venture Formation

In May 2018, ETO and Enterprise Products Partners L.P. announced the formation of a joint venture to resume service on the Old Ocean natural gas pipeline. The 24-inch diameter pipeline resumed service in May 2018 and ETO is the operator. Additionally, both parties completed the expansion of their jointly owned North Texas 36-inch pipeline that provides more capacity for deliveries from West Texas into the Old Ocean pipeline.

Acquisition of HPC

ETO previously owned a 49.99% interest in HPC, which owns RIGS. In April 2018, ETO acquired the remaining 50.01% interest in HPC. Prior to April 2018, HPC was reflected as an unconsolidated affiliate in ETO's financial statements; beginning in April 2018, RIGS is reflected as a wholly-owned subsidiary in ETO's financial statements.

ETO Series C Preferred Units Issuance

In April 2018, ETO issued 18 million of its 7.375% Series C Preferred Units (liquidation preference of $25 per unit) resulting in total gross proceeds of $450 million. The proceeds were used to repay amounts outstanding under ETO's revolving credit facility and for general partnership purposes.

CDM Contribution

On April 2, 2018, ET acquired a controlling interest in USAC, a publicly traded partnership that provides compression services in the United States. Specifically the Partnership acquired (i) all of the outstanding limited liability company interests in USA Compression GP, LLC ("USAC GP"), the general partner of USAC, and (ii) 12,466,912 USAC common units representing limited partner interests in USAC for cash consideration equal to $250 million (the "USAC Transaction"). Concurrently, USAC cancelled its incentive distribution rights and converted its economic general partner interest into a non-economic general partner interest in exchange for the issuance of 8,000,000 USAC common units to USAC GP.

Concurrent with these transactions, ETO contributed to USAC all of the issued and outstanding membership interests of CDM for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 USAC common units, (ii) 6,397,965 units of a new class of units representing limited partner interests in USAC ("USAC Class B Units") and (iii) $1.23 billion in cash, including customary closing adjustments (the "CDM Contribution"). The USAC Class B Units have substantially all of the rights and obligations of a USAC common unit, except the USAC Class B Units will not participate in distributions for the first four quarters following the closing date of April 2, 2018. Each USAC Class B Unit will automatically convert into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019.

New Ethane Export Facility Joint Venture

In March 2018, ETO and Satellite Petrochemical USA Corp. ("Satellite") entered into definitive agreements to form a joint venture, Orbit Gulf Coast NGL Exports, LLC ("Orbit"), with the purpose of constructing a new export terminal on the United States Gulf Coast to provide ethane to Satellite for consumption at their ethane cracking facilities in China. At the terminal, Orbit will construct an 800 MBbls refrigerated ethane storage tank, a 175 MBbls/d ethane refrigeration facility and a 20-inch ethane pipeline originating at ETO's Mont Belvieu fractionators that will make deliveries to the terminal as well as domestic markets in the region. ETO will be the operator of the Orbit assets, provide storage and marketing services for Satellite and provide Satellite with approximately 150 MBbls/d of ethane under a long-term, demand-based agreement. Additionally, ETO will construct and wholly own the infrastructure that is required to both supply ethane to the pipeline and to load the ethane on to very large ethane carriers destined for Satellite's newly constructed ethane crackers in China's Jiangsu Province. Subject to Chinese Governmental approval, it is anticipated that the Orbit export terminal will be ready for commercial service in the fourth quarter of 2020.

Sunoco LP Retail Store and Real Estate Sales

On April 1, 2018, Sunoco LP completed the conversion of 207 retail sites located in certain West Texas, Oklahoma and New Mexico markets to a single commission agent. Under the commission agent model, Sunoco LP owns, prices and sells fuel at the sites, paying the commission agent a fixed cents-per-gallon commission and receives rental income from the commission agent. The commission agent conducts all operations related to the retail stores and related restaurant locations.

On January 23, 2018, Sunoco LP closed on an asset purchase agreement with 7-Eleven and SEI Fuel Services, Inc., a Texas corporation and wholly-owned subsidiary of 7-Eleven. Under the agreement, Sunoco LP sold a portfolio of approximately 1,030 company-operated retail fuel outlets in 19 geographic regions, together with ancillary businesses and related assets, including the proprietary Laredo Taco Company brand, for an aggregate purchase price of $3.2 billion.

On January 18, 2017, with the assistance of a third-party brokerage firm, Sunoco LP launched a portfolio optimization plan to market and sell 97 real estate assets. Real estate assets included in this process are company-owned locations, undeveloped greenfield sites and other excess real estate. Properties are located in Florida, Louisiana, Massachusetts, Michigan, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas and Virginia. The properties are being sold through a sealed-bid. Of the 97 properties, 51 have been sold, one is under contract to be sold, and four continue to be marketed by the third-party brokerage firm. Additionally, 32 were sold to 7-Eleven and nine are part of the approximately 207 retail sites located in certain West Texas, Oklahoma, and New Mexico markets which are operated by a commission agent.

Sunoco LP Series A Preferred Units

On January 25, 2018, Sunoco LP redeemed all outstanding Sunoco LP Series A Preferred Units held by ET for an aggregate redemption amount of approximately $313 million. The redemption amount includes the original consideration of $300 million and a 1% call premium plus accrued and unpaid quarterly distributions.

Sunoco LP Senior Notes Offering

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028. Sunoco LP used the proceeds from the private offering, along with proceeds from its retail divestment, to: i) redeem in full its existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020 and $800 million in aggregate principal amount of 6.375% senior notes due 2023; ii) repay in full and terminate its term loan; iii) pay all closing costs in connection with its retail divestment; iv) redeem the outstanding Sunoco LP Series A Preferred Units; and v) repurchase 17,286,859 Sunoco LP common units owned by ETO.

On December 3, 2018, Sunoco LP completed an exchange of the notes for registered notes with substantially identical terms.

Sunoco LP Common Unit Repurchase

In February 2018, after the record date for Sunoco LP's fourth quarter 2017 cash distributions, Sunoco LP repurchased 17,286,859 Sunoco LP common units owned by ETO for aggregate cash consideration of approximately $540 million. ETO used the proceeds from the sale of the Sunoco LP common units to repay amounts outstanding under its revolving credit facility.

Regulatory Update

Interstate Natural Gas Transportation Regulation

Effective January 2018, the 2017 Tax and Jobs Act (the "Tax Act") changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related proposals, the FERC addressed treatment of federal income tax allowances in regulated entity rates. The FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost of service rates. The FERC issued the Revised Policy Statement in response to a remand from the United States Court of Appeals for the District of Columbia Circuit in United Airlines v. FERC, in which the court determined that the FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not "double recover" its taxes under the current policy by both including an income-tax allowance in its cost of service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, the FERC issued an order denying requests for rehearing and clarification of its Revised Policy Statement because it is non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs. In light of the rehearing order, the impacts of the FERC's policy on the treatment of income taxes may have on the rates ETO can charge for the FERC regulated transportation services are unknown at this time.

The FERC also issued a Notice of Inquiry ("2017 Tax Law NOI") requesting comments on the effect of the Tax Act on FERC jurisdictional rates. The 2017 Tax Law NOI states that of particular interest to the FERC is whether, and if so how, the FERC should address changes relating to accumulated deferred income taxes and bonus depreciation. Comments in response to the 2017 Tax Law NOI were due on or before May 21, 2018. It is unknown at this time what actions that the FERC will take, if any, following receipt of responses to the 2017 Tax Law NOI and any potential impacts from final rules or policy statements issued following the 2017 Tax Law NOI on the rates ETO can charge for FERC regulated transportation services.

Included in the March 15, 2018 proposals is a Notice of Proposed Rulemaking ("NOPR") proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, the FERC issued a Final Rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information and to make an election on how to treat its existing rates. The Final Rule suggests that this information will allow the FERC and other stakeholders to evaluate the impacts of the Tax Act and the Revised Policy Statement on each individual pipeline's rates. The Final Rule also requires that each FERC regulated natural gas pipeline select one of four options: file a limited Natural Gas Act ("NGA") Section 4 filing reducing its rates only as required related to the Tax Act and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. For the limited NGA Section 4 option, the FERC clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Trunkline, ETC Tiger Pipeline, LLC and Panhandle filed their respective FERC Form No. 501-Gs on October 11, 2018. FEP, Lake Charles LNG and certain other operating subsidiaries filed their respective FERC Form No. 501-Gs on or about November 8, 2018, and Rover, FGT, Transwestern and MEP filed their respective FERC Form No. 501-Gs on or about December 6, 2018. By order issued January 16, 2019, the FERC initiated a review of Panhandle's existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Panhandle are just and reasonable and set the matter for hearing. Panhandle must file a cost and revenue study on or before April 1, 2019. An initial decision is expected to be issued in the first quarter of 2020. By order issued February 19, 2019, the FERC initiated a review of Southwest Gas Storage Company's existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Southwest Gas Storage Company are just and reasonable and set the matter for hearing. Southwest Gas Storage Company must file a cost and revenue study on or before May 6, 2019. The FERC is directing that an initial decision be issued within 47 weeks of the date the cost and revenue study is due.

Even without action on the 2017 Tax Law NOI or as contemplated in the Final Rule, the FERC or our shippers may challenge the cost of service rates we charge. The FERC's establishment of a just and reasonable rate is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect the FERC's determination of just and reasonable cost of service rates. Although changes in these two tax related components may decrease, other components in the cost of service rate calculation may increase and result in a newly calculated cost of service rate that is the same as or greater than the prior cost of service rate. Moreover, we receive revenues from our pipelines based on a variety of rate structures, including cost of service rates, negotiated rates, discounted rates and market-based rates. Many of our interstate pipelines, such as ETC Tiger Pipeline, LLC, MEP and FEP, have negotiated market rates that were agreed to by customers in connection with long-term contracts entered into to support the construction of the pipelines. Other systems, such as FGT, Transwestern and Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. We do not expect market-based rates, negotiated rates or discounted rates that are not tied to the cost of service rates to be affected by the Revised Policy Statement or any final regulations that may result from the March 15, 2018 proposals. The revenues we receive from natural gas transportation services we provide pursuant to cost of service based rates may decrease in the future as a result of the ultimate outcome of the NOI, the Final Rule, and the Revised Policy Statement, combined with the reduced corporate federal income tax rate established in the Tax Act. The extent of any revenue reduction related to our cost of service rates, if any, will depend on a detailed review of all of ETO's cost of service components and the outcomes of any challenges to our rates by the FERC or our shippers.

The FERC issued a Notice of Inquiry on April 19, 2018 ("Pipeline Certification NOI"), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed as a result of the Pipeline Certification NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. Comments in response to the Pipeline Certification NOI were due on or before July 25, 2018. We do not expect that any change in this policy would affect us in a materially different manner than any other natural gas pipeline company operating in the United States.

Interstate Liquids Transportation Regulation

The FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index, or PPI. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. The FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 1.23 percent. Many existing pipelines utilize the FERC liquids index to change transportation rates annually every July 1. With respect to liquids and refined products pipelines subject to FERC jurisdiction, the Revised Policy Statement requires the pipeline to reflect the impacts to its cost of service from the Revised Policy Statement and the Tax Act on Page 700 of FERC Form No. 6. This information will be used by the FERC in its next five year review of the liquids pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Act in the determination of indexed rates prospectively, effective July 1, 2021. The FERC's establishment of a just and reasonable rate, including the determination of the appropriate liquids pipeline index, is based on many components, and tax related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect the FERC's determination of the appropriate pipeline index. Accordingly, depending on the FERC's application of its indexing rate methodology for the next five year term of index rates, the Revised Policy Statement and tax effects related to the Tax Act may impact our revenues associated with any transportation services we may provide pursuant to cost of service based rates in the future, including indexed rates.

Trends and Outlook

We continue to evaluate and execute strategies to enhance unitholder value through growth, as well as the integration and optimization of our diversified asset portfolio. We intend to target a minimum distribution coverage ratio of 1.50x, thereby promoting a prudent balance between distribution rate increases and enhanced financial flexibility and strength while maintaining our investment grade ratings. We anticipate significant earnings growth in 2019 from the completion of our project backlog. We also continue to seek asset optimization opportunities through strategic transactions among us and our subsidiaries and/or affiliates, and we expect to continue to evaluate and execute on such opportunities. As we have in the past, we will evaluate growth projects and acquisitions as such opportunities may be identified in the future, and we believe that the current capital markets are conducive to funding such future projects.

With respect to commodity prices, natural gas prices have remained comparatively low during most of the last twelve months as associated gas from shale oil resources has provided additional supply to the market, while United States consumption has been relatively flat. This supports natural gas export projects to Mexico as well as LNG exports. Consequently, the Gulf Coast will likely be the fastest-growing demand market for United States natural gas.

Unlike natural gas, crude oil prices are influenced more by international markets than by domestic resources and technological advances. Prices have rebounded significantly from 2016 lows, signaling United States crude and NGL production should continue to grow rapidly, particularly in the Permian Basin and Bakken Shale, while domestic consumption falls. Energy exports from the United States are continuing to grow as a result, providing strong spreads from North Dakota and West Texas to the Gulf Coast.

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.

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, 2018 Compared to the Year Ended December 31, 2017

Consolidated Results

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 927	$ 626	$ 301
Interstate transportation and storage	1,680	1,274	406
Midstream	1,627	1,481	146
NGL and refined products transportation and services	1,979	1,641	338
Crude oil transportation and services	2,330	1,379	951
Investment in Sunoco LP	638	732	(94)
Investment in USAC	289	—	289
All other	40	187	(147)
Total Segment Adjusted EBITDA	9,510	7,320	2,190
Depreciation, depletion and amortization	(2,859)	(2,554)	(305)
Interest expense, net	(2,055)	(1,922)	(133)
Impairment losses	(431)	(1,039)	608
Gains (losses) on interest rate derivatives	47	(37)	84
Non-cash compensation expense	(105)	(99)	(6)
Unrealized gains (losses) on commodity risk management activities	(11)	59	(70)
Inventory valuation adjustments	(85)	24	(109)
Losses on extinguishments of debt	(112)	(89)	(23)
Adjusted EBITDA related to unconsolidated affiliates	(655)	(716)	61
Equity in earnings of unconsolidated affiliates	344	144	200
Impairment of investments in unconsolidated affiliates	—	(313)	313
Adjusted EBITDA related to discontinued operations	25	(223)	248
Other, net	21	155	(134)
Income from continuing operations before income tax (expense) benefit	3,634	710	2,924
Income tax (expense) benefit from continuing operations	(4)	1,833	(1,837)
Income from continuing operations	3,630	2,543	1,087
Loss from discontinued operations, net of income taxes	(265)	(177)	(88)
Net income	$ 3,365	$ 2,366	$ 999

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

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

- an increase of $121 million recognized by ETO primarily related to an increase in long-term debt, including additional senior note issuances and borrowings under our revolving credit facilities; and
- an increase of $78 million due to the acquisition of USAC on April 2, 2018; partially offset by
- a decrease of $65 million recognized by Sunoco LP primarily due to the repayment in full of its term loan and lower interest rates on its senior notes as a result of Sunoco LP's January 23, 2018 issuance of senior notes which paid off in full Sunoco LP's previously outstanding senior notes which had higher interest rates.

Impairment Losses. During the year ended December 31, 2018, the Partnership recognized goodwill impairments of $378 million and asset impairments of $4 million related to its midstream operations and asset impairments of $9 million related to its crude operations idle leased assets. Sunoco LP recognized a $30 million indefinite-lived intangible impairment related to its contractual rights. USAC recognized a $9 million fixed asset impairment related to certain idle compressor assets.

During the year ended December 31, 2017, the Partnership recorded impairments to goodwill associated with the compression business of $223 million, the entity that owns the general partner of Panhandle of $229 million, interstate transportation and storage operations of $262 million and refined products transportation and services operations of $79 million. Sunoco LP recognized goodwill impairments of $387 million, of which $102 million was allocated to continuing operations. In addition, during the year ended December 31, 2017, the Partnership recorded an impairment to the property, plant and equipment of Sea Robin of $127 million. Additional discussion on these impairments is included in "Estimates and Critical Accounting Policies" below.

Gains (Losses) on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Gains (losses) on interest rate derivatives during the years ended December 31, 2018 and 2017 resulted from an increase in forward interest rates in 2018 and a decrease in forward interest rates in 2017, which caused our forward-starting swaps to change in value.

Unrealized Gains (Losses) on Commodity Risk Management Activities. See additional information on unrealized gain (loss) 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 LP due to changes in fuel prices between periods.

Losses on Extinguishments of Debt. Amounts were related to Sunoco LP's senior note and term loan redemption in January 2018.

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 Investments in Unconsolidated Affiliates. During the year ended December 31, 2017, the Partnership recorded impairments to its investments in FEP of $141 million and HPC of $172 million. Additional discussion on these impairments is included in "Estimates and Critical Accounting Policies" below.

Adjusted EBITDA Related to Discontinued Operations. Amounts were related to the operations of Sunoco LP's retail business that were disposed of in January 2018.

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

Income Tax (Expense) Benefit. On December 22, 2017, the Tax Cuts and Jobs Act was signed into law. Among other provisions, the highest corporate federal income tax rate was reduced from 35% to 21% for taxable years beginning after December 31, 2017. As a result, the Partnership recognized a deferred tax benefit of $1.81 billion in December 2017. For the year ended December 31, 2018, the Partnership recorded an income tax expense due to pre-tax income at its corporate subsidiaries, partially offset by a state statutory rate reduction.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 141	$ 144	$ (3)
FEP	55	53	2
MEP	31	38	(7)
HPC [(1)(2)]	3	(168)	171
Other	114	77	37
Total equity in earnings of unconsolidated affiliates	$ 344	$ 144	$ 200
Adjusted EBITDA related to unconsolidated affiliates[(3)]:			
Citrus	$ 337	$ 336	$ 1
FEP	74	74	—
MEP	81	88	(7)
HPC [(2)]	9	46	(37)
Other	154	172	(18)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 655	$ 716	$ (61)
Distributions received from unconsolidated affiliates:			
Citrus	$ 171	$ 156	$ 15
FEP	68	47	21
MEP	48	114	(66)
HPC [(2)]	—	35	(35)
Other	111	80	31
Total distributions received from unconsolidated affiliates	$ 398	$ 432	$ (34)

(1) For the year ended December 31, 2017, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by HPC, which reduced the Partnership's equity in earnings by $185 million.

(2) The partnership previously owned a 49.99% interest in HPC, which owns RIGS. In April 2018, we acquired the remaining 50.01% interest in HPC. Prior to April 2018, HPC was reflected as an unconsolidated affiliate in our financial statements; beginning in April 2018, RIGS is reflected as a wholly-owned subsidiary in our financial statements.

(3) 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

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 in "Item 8. Financial Statements and Supplementary Data."

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

	Years Ended December 31,	
	2018	2017
Segment Margin:		
Intrastate transportation and storage	$ 1,072	$ 756
Interstate transportation and storage	1,682	1,131
Midstream	2,377	2,182
NGL and refined products transportation and services	2,661	2,140
Crude oil transportation and services	2,893	1,877
Investment in Sunoco LP	1,122	1,108
Investment in USAC	441	—
All other	222	392
Intersegment eliminations	(41)	(29)
Total segment margin	12,429	9,557
Less:		
Operating expenses	3,089	2,644
Depreciation, depletion and amortization	2,859	2,554
Selling, general and administrative	702	599
Impairment losses	431	1,039
Operating income	$ 5,348	$ 2,721

Intrastate Transportation and Storage

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Natural gas transported (BBtu/d)	10,873	8,760	2,113
Revenues	$ 3,737	$ 3,083	$ 654
Cost of products sold	2,665	2,327	338
Segment margin	1,072	756	316
Unrealized (gains) losses on commodity risk management activities	38	(5)	43
Operating expenses, excluding non-cash compensation expense	(189)	(168)	(21)
Selling, general and administrative expenses, excluding non-cash compensation expense	(27)	(22)	(5)
Adjusted EBITDA related to unconsolidated affiliates	32	64	(32)
Other	1	1	—
Segment Adjusted EBITDA	$ 927	$ 626	$ 301

Volumes. For the year ended December 31, 2018 compared to the prior year, transported volumes increased primarily due to favorable market pricing spreads, as well as the impact of reflecting RIGS assets as a consolidated subsidiary beginning in April 2018.

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

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Transportation fees	$ 525	$ 448	$ 77
Natural gas sales and other (excluding unrealized gains and losses)	510	196	314
Retained fuel revenues (excluding unrealized gains and losses)	59	58	1
Storage margin, including fees (excluding unrealized gains and losses)	16	49	(33)
Unrealized gains (losses) on commodity risk management activities	(38)	5	(43)
Total segment margin	$ 1,072	$ 756	$ 316

Segment Adjusted EBITDA. For the year ended December 31, 2018 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 $314 million in realized natural gas sales and other due to higher realized gains from pipeline optimization activity;
- a net increase of $14 million due to the consolidation of RIGS beginning in April 2018, resulting in increases in transportation fees, operating expenses, and selling, general and administrative expenses of $73 million, $16 million and $6 million, respectively, and a decrease of $37 million in Adjusted EBITDA related to unconsolidated affiliates; and
- an increase of $4 million in transportation fees, excluding the impact of consolidating RIGS as discussed above, primarily due to new contracts and the impact of the Red Bluff Express pipeline coming online in May 2018; partially offset by
- a decrease of $33 million in realized storage margin primarily due to an adjustment to the Bammel storage inventory, lower storage fees and lower realized derivative gains.

Interstate Transportation and Storage

	Years Ended December 31, 2018	2017	Change
Natural gas transported (BBtu/d)	9,542	6,058	3,484
Natural gas sold (BBtu/d)	17	18	(1)
Revenues	$ 1,682	$ 1,131	$ 551
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(431)	(315)	(116)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(63)	(41)	(22)
Adjusted EBITDA related to unconsolidated affiliates	492	498	(6)
Other	—	1	(1)
Segment Adjusted EBITDA	$ 1,680	$ 1,274	$ 406

Volumes. For the year ended December 31, 2018 compared to the prior year, transported volumes reflected increases of 1,919 BBtu/d as a result of the initiation of service on the Rover pipeline; increases of 572 BBtu/d and 439 BBtu/d on the Panhandle and Trunkline pipelines, respectively, due to higher demand resulting from colder weather and increased utilization by the Rover pipeline; 375 BBtu/d on the Tiger pipeline as a result of production increases in the Haynesville Shale, and 145 BBtu/d on the Transwestern pipeline resulting from favorable market opportunities in the West, midcontinent and Waha areas from the Permian supply basin.

Segment Adjusted EBITDA. For the year ended December 31, 2018 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $359 million associated with the Rover pipeline with increases of $485 million in revenues, $105 million in net operating expenses and $21 million in selling, general and administrative expenses and other; and
- an aggregate increase of $66 million in revenues, excluding the incremental revenue related to the Rover pipeline discussed above, primarily due to capacity sold at higher rates on the Transwestern and Panhandle pipelines; partially offset by
- an increase of $11 million in operating expenses, excluding the incremental expenses related to the Rover pipeline discussed above, primarily due to increases in maintenance project costs due to scope and level of activity; and
- a decrease of $6 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to lower margins on MEP due to lower rates on renewals of expiring long term contracts.

Midstream

	Years Ended December 31, 2018	2017	Change
Gathered volumes (BBtu/d)	12,126	10,956	1,170
NGLs produced (MBbls/d)	540	472	68
Equity NGLs (MBbls/d)	29	27	2
Revenues	$ 7,522	$ 6,943	$ 579
Cost of products sold	5,145	4,761	384
Segment margin	2,377	2,182	195
Unrealized gains on commodity risk management activities	—	(15)	15
Operating expenses, excluding non-cash compensation expense	(705)	(638)	(67)
Selling, general and administrative expenses, excluding non-cash compensation expense	(81)	(78)	(3)
Adjusted EBITDA related to unconsolidated affiliates	33	28	5
Other	3	2	1
Segment Adjusted EBITDA	$ 1,627	$ 1,481	$ 146

Volumes. Gathered volumes and NGL production increased during the year ended December 31, 2018 compared to the prior year primarily due to increases in the North Texas, Permian and Northeast regions, partially offset by smaller declines in other regions.

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

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Gathering and processing fee-based revenues	$ 1,807	$ 1,690	$ 117
Non-fee based contracts and processing (excluding unrealized gains and losses)	570	477	93
Unrealized gains on commodity risk management activities	—	15	(15)
Total segment margin	$ 2,377	$ 2,182	$ 195

Segment Adjusted EBITDA. For the year ended December 31, 2018 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $117 million in fee-based margin due to growth in the North Texas, Permian and Northeast regions, offset by declines in the Ark-La-Tex and midcontinent/Panhandle regions;
- an increase of $60 million in non fee-based margin due to increased throughput volume in the North Texas and Permian regions;
- an increase of $33 million in non fee-based margin due to higher crude oil and NGL prices; and
- an increase of $5 million in Adjusted EBITDA related to unconsolidated affiliates due to higher earnings from our Aqua, Mi Vida and Ranch joint ventures; partially offset by
- an increase of $67 million in operating expenses primarily due to increases of $20 million in outside services, $19 million in materials, $8 million in maintenance project costs, $7 million in ad valorem taxes, $6 million in employee costs and $6 million in office expenses; and
- an increase of $3 million in selling, general and administrative expenses due to higher professional fees.

NGL and Refined Products Transportation and Services

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
NGL transportation volumes (MBbls/d)	1,027	863	164
Refined products transportation volumes (MBbls/d)	621	624	(3)
NGL and refined products terminal volumes (MBbls/d)	812	783	29
NGL fractionation volumes (MBbls/d)	527	427	100
Revenues	$ 11,123	$ 8,648	$ 2,475
Cost of products sold	8,462	6,508	1,954
Segment margin	2,661	2,140	521
Unrealized gains on commodity risk management activities	(86)	(26)	(60)
Operating expenses, excluding non-cash compensation expense	(604)	(478)	(126)
Selling, general and administrative expenses, excluding non-cash compensation expense	(74)	(64)	(10)
Adjusted EBITDA related to unconsolidated affiliates	82	68	14
Other	—	1	(1)
Segment Adjusted EBITDA	$ 1,979	$ 1,641	$ 338

Volumes. For the year ended December 31, 2018 compared to the prior year, NGL transportation volumes increased primarily due to increased volumes from the Permian region resulting from a ramp up in production from existing customers, higher throughput volumes on Mariner West driven by end-user facility constraints in the prior year and higher throughput from Mariner South resulting from increased export volumes.

Refined products transportation volumes decreased for the year ended December 31, 2018 compared to prior year, primarily due to timing of turnarounds at third-party refineries in the Midwest and Northeast regions.

NGL and Refined products terminal volumes increased for the year ended December 31, 2018 compared to prior year, primarily due to more volumes loaded at our Nederland terminal as propane export demand increased and higher throughput volumes at our refined products terminals in the Northeast.

Average volumes fractionated at our Mont Belvieu, Texas fractionation facility increased for the year ended December 31, 2018 compared to the prior year primarily due to increased volumes from the Permian region, as well as an increase in fractionation capacity as our fifth fractionator at Mont Belvieu came online in July 2018.

Segment Margin. The components of our NGL and refined products transportation and services segment margin were as follows:

	Years Ended December 31,		
	2018	2017	Change
Fractionators and Refinery services margin	$ 592	$ 488	$ 104
Transportation margin	1,233	990	243
Storage margin	211	214	(3)
Terminal Services margin	413	351	62
Marketing margin	126	71	55
Unrealized gains on commodity risk management activities	86	26	60
Total segment margin	$ 2,661	$ 2,140	$ 521

Segment Adjusted EBITDA. For the year ended December 31, 2018 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 in transportation margin of $243 million primarily due to a $216 million increase resulting from increased producer volumes from the Permian region on our Texas NGL pipelines, a $31 million increase due to higher throughput volumes on Mariner West driven by end-user facility constraints in the prior period, a $15 million increase resulting from a reclassification between our transportation and fractionation margins, a $9 million increase due to higher throughput volumes from the Barnett region, a $5 million increase due to higher throughput volumes on Mariner South due to system downtime in the prior period and a $4 million increase in prior period customer credits. These increases were partially offset by a $16 million decrease resulting from lower throughput volumes on Mariner East 1 due to system downtime in 2018, a $14 million decrease due to lower throughput volumes from the Southeast Texas region and a $7 million decrease resulting from the timing of deficiency fee revenue recognition;
- an increase in fractionation and refinery services margin of $104 million primarily due to a $106 million increase resulting from the commissioning of our fifth fractionator in July 2018, a $9 million increase from throughput revenue at our Mariner South export facility and a $7 million increase from blending gains as a result of improved market pricing. These increases were partially offset by a $16 million decrease resulting from a reclassification between our transportation and fractionation margins and a $2 million decrease from higher affiliate storage fees paid;
- an increase in terminal services margin of $62 million due to a $36 million increase resulting from a change in the classification of certain customer reimbursements previously recorded in operating expenses, a $14 million increase at our Nederland terminal due to increased export demand and a $12 million increase due to higher throughput at our Marcus Hook Industrial Complex. These increases were partially offset by lower terminal throughput fees in part due to the sale of one of our terminals in April 2017;
- an increase in marketing margin of $55 million due to a $48 million increase from our butane blending operations and a $22 million increase in sales of NGLs and other products at our Marcus Hook Industrial Complex due to more favorable market prices. These increases were partially offset by a $15 million decrease from the timing of optimization gains from our Mont Belvieu fractionators; and
- an increase of $14 million to adjusted EBITDA related to unconsolidated affiliates due to improved contributions from our unconsolidated refined products joint venture interests; partially offset by
- an increase of $126 million in operating expenses primarily due to a $30 million increase in costs to operate our fractionators and a $20 million increase in operating costs on our NGL pipelines as a result of higher throughput and the commissioning of our fifth fractionator in July 2018, a $36 million increase resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the

adoption of ASC 606 on January 1, 2018, increases of $24 million and $7 million to operating costs at our Marcus Hook and Nederland terminals, respectively, as a result of significantly higher volumes through both terminals in 2018, an $8 million increase to environmental reserves and a $1 million increase to overhead allocations and maintenance repairs performed on our refinery services assets; and

- an increase of $10 million in selling, general and administrative expenses primarily due to a $6 million increase in overhead costs allocated to the segment, a $2 million increase in legal fees, a $1 million increase in management fees previously recorded in operating expenses and a $1 million increase in employee costs.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2018	2017	Change
Crude Transportation Volumes (MBbls/d)	4,172	3,538	634
Crude Terminals Volumes (MBbls/d)	2,096	1,928	168
Revenue	$ 17,332	$ 11,703	$ 5,629
Cost of products sold	14,439	9,826	4,613
Segment margin	2,893	1,877	1,016
Unrealized losses on commodity risk management activities	55	1	54
Operating expenses, excluding non-cash compensation expense	(547)	(430)	(117)
Selling, general and administrative expenses, excluding non-cash compensation expense	(86)	(82)	(4)
Adjusted EBITDA related to unconsolidated affiliates	15	13	2
Segment Adjusted EBITDA	$ 2,330	$ 1,379	$ 951

Segment Adjusted EBITDA. For the year ended December 31, 2018 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 $1.07 billion in segment margin (excluding unrealized losses on commodity risk management activities) primarily due to the following: a $586 million increase resulting from placing the Bakken pipeline in service in the second quarter of 2017; a $266 million increase resulting from higher throughput on our Texas crude pipeline system primarily due to increased production from Permian producers; and a $189 million increase (excluding a net change of $54 million in unrealized losses on commodity risk management activities) from our crude oil acquisition and marketing business primarily resulting from improved basis differentials between the Permian and Bakken producing regions to our Nederland terminal on the Texas gulf coast; and a $28 million increase primarily from higher throughput and ship loading fees at our Nederland terminal; and
- an increase of $2 million in Adjusted EBITDA related to unconsolidated affiliates due to increased jet fuel sales from our joint ventures; partially offset by
- an increase of $117 million in operating expenses primarily due to a $67 million increase to throughput related costs on existing assets; a $36 million increase resulting from placing the Bakken pipeline in service in the second quarter of 2017; a $26 million increase resulting from the addition of certain joint venture transportation assets in the second quarter of 2017; and a $5 million increase from ad valorem taxes; partially offset by an $17 million decrease in insurance and environmental related expenses; and
- an increase of $4 million in selling, general and administrative expenses primarily due to increases associated with placing our Bakken Pipeline in service in the second quarter of 2017.

Investment in Sunoco LP

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Revenues	$ 16,994	$ 11,723	$ 5,271
Cost of products sold	15,872	10,615	5,257
Segment margin	1,122	1,108	14
Unrealized (gains) losses on commodity risk management activities	6	(3)	9
Operating expenses, excluding non-cash compensation expense	(435)	(456)	21
Selling, general and administrative, excluding non-cash compensation expense	(129)	(116)	(13)
Inventory fair value adjustments	85	(24)	109
Adjusted EBITDA from discontinued operations	(25)	223	(248)
Other, net	14	—	14
Segment Adjusted EBITDA	$ 638	$ 732	$ (94)

The Investment in Sunoco LP segment reflects the consolidated results of Sunoco LP.

Segment Adjusted EBITDA. For the year ended December 31, 2018 compared to the prior year, Segment Adjusted EBITDA related to the Investment in Sunoco LP segment decreased due to the net impacts of the following:

- a decrease of $248 million in Adjusted EBITDA from discontinued operations primarily due to Sunoco LP's retail divestment in January 2018; partially offset by
- an increase of $109 million in inventory fair value adjustments due to changes in fuel prices between periods;
- an increase of $14 million in margin primarily due to an increase in rental income as a result of the increase in commission agent sites in the current year, offset by decreases in the gross profit on motor fuel sales; and
- a net decrease of $8 million in operating and selling, general and administrative expenses primarily due to decreased rent expense.

Investment in USAC

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Revenues	$ 508	$ —	$ 508
Cost of products sold	67	—	67
Segment margin	441	—	441
Operating expenses, excluding non-cash compensation expense	(110)	—	(110)
Selling, general and administrative, excluding non-cash compensation expense	(50)	—	(50)
Other, net	8	—	8
Segment Adjusted EBITDA	$ 289	$ —	$ 289

Amounts reflected above for the year ended December 31, 2018 represents the results of operations for USAC from April 2, 2018, the date ET obtained control of USAC, through December 31, 2018. Changes between periods are due to the consolidation of USAC beginning April 2, 2018.

All Other

	Years Ended December 31, 2018	Years Ended December 31, 2017	Change
Revenue	$ 2,228	$ 2,901	$ (673)
Cost of products sold	2,006	2,509	(503)
Segment margin	222	392	(170)
Unrealized gains on commodity risk management activities	(2)	(11)	9
Operating expenses, excluding non-cash compensation expense	(56)	(117)	61
Selling, general and administrative expenses, excluding non-cash compensation expense	(124)	(135)	11
Adjusted EBITDA related to unconsolidated affiliates	1	45	(44)
Other and eliminations	(1)	13	(14)
Segment Adjusted EBITDA	$ 40	$ 187	$ (147)

Amounts reflected in our all other segment primarily include:

- our natural gas marketing operations;
- our wholly-owned natural gas compression operations;
- a non-controlling interest in PES. Prior to PES's reorganization in August 2018, ETO's 33% interest in PES was reflected as an unconsolidated affiliate; subsequent the August 2018 reorganization, ETO holds an approximately 8% interest in PES and no longer reflects PES as an affiliate; and
- our investment in coal handling facilities.

Segment Adjusted EBITDA. For the year ended December 31, 2018 compared to the prior year, Segment Adjusted EBITDA decreased due to the net impact of the following:

- a decrease of $98 million due to the contribution of CDM to USAC in April 2018, subsequent to which CDM is reflected in the Investment in USAC segment;
- a decrease of $38 million in Adjusted EBITDA related to unconsolidated affiliates from ETO's investment in PES primarily due to ETO's lower ownership in PES subsequent to its reorganization, which resulted in PES no longer being reflected as an affiliate beginning in the third quarter of 2018;
- a decrease of $4 million due to merger and acquisition expenses related to the Energy Transfer Merger in 2018; and
- a decrease of $15 million due to a one-time fee received from a joint venture affiliate in 2017; partially offset by
- an increase of $7 million due to lower transport fees resulting from the expiration of a capacity commitment on Trunkline pipeline;
- an increase of $6 million due to a decrease in losses from mark-to-market of physical system gas; and
- an increase of $7 million due to increased margin from ETO's compression equipment business.

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Consolidated Results

	Years Ended December 31,		
	2017	2016	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 626	$ 613	$ 13
Interstate transportation and storage	1,274	1,297	(23)
Midstream	1,481	1,133	348
NGL and refined products transportation and services	1,641	1,496	145
Crude oil transportation and services	1,379	834	545
Investment in Sunoco LP	732	665	67
All other	187	97	90
Total	7,320	6,135	1,185
Depreciation, depletion and amortization	(2,554)	(2,216)	(338)
Interest expense, net	(1,922)	(1,804)	(118)
Gains on acquisitions	—	83	(83)
Impairment losses	(1,039)	(1,040)	1
Losses on interest rate derivatives	(37)	(12)	(25)
Non-cash compensation expense	(99)	(70)	(29)
Unrealized (gains) losses on commodity risk management activities	59	(136)	195
Inventory valuation adjustments	24	97	(73)
Losses on extinguishments of debt	(89)	—	(89)
Adjusted EBITDA related to unconsolidated affiliates	(716)	(675)	(41)
Equity in earnings of unconsolidated affiliates	144	270	(126)
Impairment of investment in an unconsolidated affiliate	(313)	(308)	(5)
Adjusted EBITDA related to discontinued operations	(223)	(199)	(24)
Other, net	155	79	76
Income from continuing operations before income tax benefit	710	204	506
Income tax benefit from continuing operations	1,833	258	1,575
Income from continuing operations	2,543	462	2,081
Loss from discontinued operations, net of income taxes	(177)	(462)	285
Net income	$ 2,366	$ —	$ 2,366

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased primarily due to additional depreciation and amortization from assets recently placed in service.

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

- an increase of $48 million of expense recognized by Sunoco LP primarily due to increased term loan borrowings and the issuance of senior notes;
- an increase of $48 million of expense recognized by ETO primarily due to 2017 debt issuances by ETO and its consolidated subsidiaries; and
- an increase of $20 million of expense recognized by the Parent Company primarily due to increased borrowings.

Gains on acquisitions. The Partnership recorded gains of $83 million in connection with recent acquisitions during 2016, including $41 million related to the acquisition of the remaining interest in SunVit.

Impairment Losses. During the year ended December 31, 2017, the Partnership recorded goodwill impairments of $223 million related to the compression business of $223 million, $229 million related to Panhandle, $262 million related to the interstate transportation and storage segment and $79 million related to the NGL and refined products transportation and services segment. Sunoco LP recognized goodwill impairments of $387 million in 2017, of which $102 million was allocated to continuing operations. In addition, during the year ended December 31, 2017, the Partnership recorded an impairment to the property, plant and equipment of Sea Robin of $127 million.

During the year ended December 31, 2016, the Partnership recorded goodwill impairments of $638 million in the interstate transportation and storage segment and $32 million in the midstream segment. Sunoco LP recognized goodwill impairments of $641 million, of which $227 million was allocated to continuing operations. 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. Additional discussion on these impairments is included in "Estimates and Critical Accounting Policies" below.

Losses on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Losses on interest rate derivatives during the year ended December 31, 2017 and 2016 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 the discussion of segment results below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco LP 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. During the year ended December 31, 2017, the Partnership recorded impairments to its investments in FEP of $141 million and HPC of $172 million. During the year ended December 31, 2016 the Partnership recorded an impairment to its investment in MEP of $308 million. Additional discussion on these impairments is included in "Estimates and Critical Accounting Policies" below.

Adjusted EBITDA Related to Discontinued Operations. Amounts were related to the operations of Sunoco LP's retail business that was classified as held for sale.

Other, net. Other, net in 2017 and 2016 primarily includes amortization of regulatory assets and other income and expense amounts.

Income Tax Benefit. On December 22, 2017, the Tax Cuts and Jobs Act was signed into law. Among other provisions, the highest corporate federal income tax rate was reduced from 35% to 21% for taxable years beginning after December 31, 2017. As a result, the Partnership recognized a deferred tax benefit of $1.81 billion in December 2017. For the year ended December 2016, the Partnership recorded an income tax benefit due to pre-tax losses at its corporate subsidiaries.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2017	Years Ended December 31, 2016	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 144	$ 102	$ 42
FEP	53	51	2
MEP	38	40	(2)
HPC[(1)]	(168)	31	(199)
Other	77	46	31
Total equity in earnings of unconsolidated affiliates	$ 144	$ 270	$ (126)
Adjusted EBITDA related to unconsolidated affiliates[(2)]:			
Citrus	$ 336	$ 329	$ 7
FEP	74	75	(1)
MEP	88	90	(2)
HPC	46	61	(15)
Other	172	120	52
Total Adjusted EBITDA related to unconsolidated affiliates	$ 716	$ 675	$ 41
Distributions received from unconsolidated affiliates:			
Citrus	$ 156	$ 144	$ 12
FEP	47	65	(18)
MEP	114	74	40
HPC	35	51	(16)
Other	80	69	11
Total distributions received from unconsolidated affiliates	$ 432	$ 403	$ 29

(1) For the year ended December 31, 2017, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by HPC, which reduced the Partnership's equity in earnings by $185 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

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

	Years Ended December 31, 2017	Years Ended December 31, 2016
Segment Margin:		
Intrastate transportation and storage	$ 756	$ 716
Interstate transportation and storage	1,131	1,166
Midstream	2,182	1,798
NGL and refined products transportation and services	2,140	1,856
Crude oil transportation and services	1,877	1,123
Investment in Sunoco LP	1,108	1,156
All other	392	330
Intersegment eliminations	(29)	(46)
Total segment margin	9,557	8,099
Less:		
Operating expenses	2,644	2,336
Depreciation, depletion and amortization	2,554	2,216
Selling, general and administrative	599	656
Impairment losses	1,039	1,040
Operating income	$ 2,721	$ 1,851

Intrastate Transportation and Storage

	Years Ended December 31, 2017	Years Ended December 31, 2016	Change
Natural gas transported (BBtu/d)	8,760	8,427	333
Revenues	$ 3,083	$ 2,613	$ 470
Cost of products sold	2,327	1,897	430
Segment margin	756	716	40
Unrealized (gains) losses on commodity risk management activities	(5)	19	(24)
Operating expenses, excluding non-cash compensation expense	(168)	(162)	(6)
Selling, general and administrative, excluding non-cash compensation expense	(22)	(22)	—
Adjusted EBITDA related to unconsolidated affiliates	64	61	3
Other	1	1	—
Segment Adjusted EBITDA	$ 626	$ 613	$ 13

Volumes. For the year ended December 31, 2017 compared to the prior year, transported volumes increased primarily due to higher demand for exports to Mexico, more favorable market pricing, and the addition of new pipelines to our intrastate pipeline system. These increases were partially offset by lower production volumes in the Barnett Shale region.

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

	Years Ended December 31, 2017	Years Ended December 31, 2016	Change
Transportation fees	$ 448	$ 505	$ (57)
Natural gas sales and other (excluding unrealized gains and losses)	196	118	78
Retained fuel revenues (excluding unrealized gains and losses)	58	51	7
Storage margin, including fees (excluding unrealized gains and losses)	49	61	(12)
Unrealized gains (losses) on commodity risk management activities	5	(19)	24
Total segment margin	$ 756	$ 716	$ 40

Segment Adjusted EBITDA. For the year ended December 31, 2017 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 $78 million in natural gas sales and other primarily due to higher realized gains from pipeline optimization activity;
- an increase of $7 million in retained fuel sales primarily due to higher market prices. The average spot price at the Houston Ship Channel location increased 22% for the year ended December 31, 2017 compared to the prior year; and
- an increase of $3 million in adjusted EBITDA related to unconsolidated affiliates primarily due to an increase of $16 million related to two new joint venture pipelines placed in service in 2017, offset by a decrease of $6 million due to lower demand volumes related to renegotiation of a contract on our Louisiana intrastate pipeline system in 2017 and a decrease of $7 million due to a reserve recorded in 2017 pursuant to the bankruptcy filing of a transport customer on our Louisiana intrastate system; partially offset by
- a decrease of $57 million in transportation fees due to renegotiated contracts resulting in lower billed volumes. This decrease was offset by increased margin from optimization activity recorded in natural gas sales and other;
- a decrease of $12 million in storage margin due to the timing of withdrawals and sales of natural gas from our Bammel storage cavern; and
- an increase of $6 million in operating expenses primarily due to higher compression fuel expense relating to increased market price and run times at various compressor stations.

Interstate Transportation and Storage

	Years Ended December 31, 2017	Years Ended December 31, 2016	Change
Natural gas transported (BBtu/d)	6,058	5,476	582
Natural gas sold (BBtu/d)	18	19	(1)
Revenues	$ 1,131	$ 1,166	$ (35)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(315)	(318)	3
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(41)	(40)	(1)
Adjusted EBITDA related to unconsolidated affiliates	498	494	4
Other	1	(5)	6
Segment Adjusted EBITDA	$ 1,274	$ 1,297	$ (23)

Volumes. For the year ended December 31, 2017 compared to the prior year, transported volumes increased 283 BBtu/d due to the partial in service of the Rover pipeline, 148 BBtu/d on the Tiger pipeline due to an increase in production in the Haynesville Shale and deliveries into third party storage and the intrastate markets, and 128 BBtu/d and 78 BBtu/d on the Trunkline and Panhandle pipelines, respectively, due to higher demand resulting from colder weather.

Segment Adjusted EBITDA. For the year ended December 31, 2017 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 net decrease of $35 million in revenues primarily due to a decrease in reservation revenues of $45 million on the Panhandle, Trunkline and Transwestern pipelines, a decrease of $17 million in gas parking service related revenues on the Panhandle and Trunkline pipelines primarily due to lack of customer demand resulting from weak spreads, a decrease of $19 million in revenues on the Tiger pipeline due to contract restructuring, and a decrease of $5 million on the Sea Robin pipeline due to producer maintenance and production declines. These decreases were partially offset by $55 million of incremental revenues from the placement in partial service of the Rover pipeline effective August 31, 2017; partially offset by
- a decrease of $3 million in operating expenses primarily due to lower allocated costs of $8 million and lower lease storage expense of $4 million due to expiration of a lease. These decreases were partially offset by higher ad valorem taxes resulting from higher valuations;
- an increase of $4 million in adjusted EBITDA related to unconsolidated affiliates due to an increase of $6 million related to a legal settlement, an increase of $3 million resulting from higher sales of short-term firm capacity on Citrus and $2 million related to higher tax gross up income from reimbursable projects on Citrus. These increases were partially offset by lower reservation revenues on MEP primarily due to a contract modification and expiring contracts; and
- an increase of $6 million in other primarily due to higher tax gross up income from reimbursable projects.

Midstream

	Years Ended December 31,		
	2017	2016	Change
Gathered volumes (BBtu/d):	10,956	9,814	1,142
NGLs produced (MBbls/d):	472	438	34
Equity NGLs (MBbls/d):	27	31	(4)
Revenues	$ 6,943	$ 5,179	$ 1,764
Cost of products sold	4,761	3,381	1,380
Segment margin	2,182	1,798	384
Unrealized (gains) losses on commodity risk management activities	(15)	15	(30)
Operating expenses, excluding non-cash compensation expense	(638)	(621)	(17)
Selling, general and administrative, excluding non-cash compensation expense	(78)	(84)	6
Adjusted EBITDA related to unconsolidated affiliates	28	24	4
Other	2	1	1
Segment Adjusted EBITDA	$ 1,481	$ 1,133	$ 348

Volumes. Gathered volumes and NGL production increased during the year ended December 31, 2017 compared to the prior year primarily due to recent acquisitions, including PennTex, and gains in the Permian, Northeast and South Texas regions, partially offset by basin declines in North Texas and Midcontinent/Panhandle regions.

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

	Years Ended December 31,		
	2017	2016	Change
Gathering and processing fee-based revenues	$ 1,690	$ 1,551	$ 139
Non-fee based contracts and processing (excluding unrealized gains and losses)	477	262	215
Unrealized gains (losses) on commodity risk management activities	15	(15)	30
Total segment margin	$ 2,182	$ 1,798	$ 384

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $150 million in non-fee based margins due to higher crude oil and NGL prices;
- an increase of $65 million in non-fee based margin due to volume increases in the Permian, Northeast and South Texas regions, partially offset by volume declines in the North Texas and the Midcontinent/Panhandle regions;
- an increase of $75 million in fee-based revenue due to minimum volume commitments in the South Texas region, as well as volume increases in the Permian and Northeast regions. These increases were partially offset by volume declines in the North Texas and the Midcontinent/Panhandle regions;
- an increase of $64 million in fee-based revenue due to recent acquisitions, including PennTex; and
- a decrease of $6 million in selling, general and administrative expenses primarily due to a favorable impact from the adjustment of certain reserves that had previously been recorded in connection with contingent matters. This decrease was partially offset by a decrease in capitalized overhead of $11 million and an increase in shared services allocation of $14 million; partially offset by
- an increase of $17 million in operating expenses primarily due to recent acquisitions, including PennTex.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2017	2016	Change
NGL transportation volumes (MBbls/d)	863	754	109
Refined products transportation volumes (MBbls/d)	624	599	25
NGL and refined products terminal volumes (MBbls/d)	783	791	(8)
NGL fractionation volumes (MBbls/d)	427	361	66
Revenues	$ 8,648	$ 6,409	$ 2,239
Cost of products sold	6,508	4,553	1,955
Segment margin	2,140	1,856	284
Unrealized (gains) losses on commodity risk management activities	(26)	69	(95)
Operating expenses, excluding non-cash compensation expense	(478)	(441)	(37)
Selling, general and administrative expenses, excluding non-cash compensation expense	(64)	(56)	(8)
Adjusted EBITDA related to unconsolidated affiliates	68	67	1
Other	1	1	—
Segment Adjusted EBITDA	$ 1,641	$ 1,496	$ 145

Volumes. For the year ended December 31, 2017 compared to the prior year, NGL and refined products transportation volumes increased from the Permian, Barnett/East Texas, Eagle Ford, Southeast Texas, Marcellus and Louisiana. NGL and refined products terminal volumes increased slightly for the year ended December 31, 2017 primarily due to increased throughput at our Marcus Hook Industrial Complex from the Northeast producing region, the impact of which was partially offset by the sale of one of our refined product terminals in April 2017.

Average volumes fractionated at our Mont Belvieu, Texas fractionation facility increased 22% for the year ended December 31, 2017 compared to the prior year primarily due to the commissioning of our fourth fractionator in October 2016, which has a capacity of 120 MBbls/d, as well as increased producer volumes as mentioned above.

Segment Margin. The components of our NGL and refined products transportation and services segment margin were as follows:

	Years Ended December 31,		
	2017	2016	Change
Fractionators and Refinery services margin	$ 488	$ 407	$ 81
Transportation margin	990	866	124
Storage margin	214	208	6
Terminal Services margin	351	322	29
Marketing margin	71	122	(51)
Unrealized gains (losses) on commodity risk management activities	26	(69)	95
Total segment margin	$ 2,140	$ 1,856	$ 284

Segment Adjusted EBITDA. For the year ended December 31, 2017 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 $124 million in transportation margin primarily due to increased throughput on our Texas NGL pipelines resulting from increased producer services as noted above and the ramp up of volumes on our Mariner East system;
- an increase of $81 million in fractionation and refinery services margin primarily due to higher NGL volumes from most major producing regions feeding our Mont Belvieu fractionation facility, the first full year of service for our fourth fractionator at Mont Belvieu, Texas and a $17 million increase from blending gains as a result of improved market pricing, as noted above;
- an increase of $29 million in terminal services margin due to a $43 million increase resulting from higher throughput volumes at our Marcus Hook and Nederland NGL terminals. This increase was partially offset by a $14 million decrease resulting from lower refined products terminal throughput and the sale of one of our refined product terminals in April 2017; and
- an increase of $6 million in storage margin primarily due to a $4 million increase from Hattiesburg storage caverns as a result of a new storage contract effective in April 2017 as well as a $2 million increase from propane and butane blending gains as a result of improved market pricing; partially offset by
- a decrease of $51 million in marketing margin primarily due to the timing of the recognition of margin from optimization activities;
- an increase of $37 million in operating expenses due to a $16 million increase related to the fourth fractionator being placed into service in October 2016, an $11 million increase related to higher utility expenses on our Texas NGL pipelines, a $5 million increase due to higher right-of-way expenses primarily on our legacy Sunoco Logistics assets and a $4 million increase from our Mont Belvieu storage assets primarily due to higher employee costs; and
- an increase of $8 million in selling, general and administrative expenses due to higher allocations.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2017	2016	Change
Crude Transportation Volumes (MBbls/d)	3,538	2,652	886
Crude Terminals Volumes (MBbls/d)	1,928	1,537	391
Revenue	$ 11,703	$ 7,539	$ 4,164
Cost of products sold	9,826	6,416	3,410
Segment margin	1,877	1,123	754
Unrealized losses on commodity risk management activities	1	2	(1)
Operating expenses, excluding non-cash compensation expense	(430)	(247)	(183)
Selling, general and administrative expenses, excluding non-cash compensation expense	(82)	(58)	(24)
Adjusted EBITDA related to unconsolidated affiliates	13	14	(1)
Segment Adjusted EBITDA	$ 1,379	$ 834	$ 545

Segment Adjusted EBITDA. For the year ended December 31, 2017 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 $724 million resulting primarily from placing our Bakken Pipeline in service in the second quarter of 2017, as well as the acquisition of a crude oil gathering system in West Texas and the addition of joint venture crude transportation assets;
- an increase of $90 million from existing transportation assets due to increased volumes throughout the system; and
- an increase of $16 million from increased throughput fees and tank rentals, primarily from increased activity at our Nederland, Texas crude terminal; offset by
- a decrease of $78 million in margin from our crude oil acquisition and marketing business resulting from less favorable market price spreads particularly in the first three quarters of 2017;
- an increase of $183 million in operating expenses primarily due to an increase of $130 million resulting primarily from placing the Bakken Pipeline as well as certain joint venture crude transportation assets in service in the first and second quarters of 2017, respectively, an increase of $46 million due to higher utilities, line testing, and environmental costs from existing transport assets and an increase of $6 million for losses related to Hurricane Harvey; and
- an increase of $24 million in selling, general and administrative expenses primarily due to merger fees and legal and environmental reserves.

Investment in Sunoco LP

	Years Ended December 31,		
	2017	2016	Change
Revenues	$ 11,723	$ 9,986	$ 1,737
Cost of products sold	10,615	8,830	1,785
Segment margin	1,108	1,156	(48)
Unrealized (gains) losses on commodity risk management activities	(3)	5	(8)
Operating expenses, excluding non-cash compensation expense	(456)	(455)	(1)
Selling, general and administrative, excluding non-cash compensation expense	(116)	(143)	27
Inventory valuation adjustments	(24)	(97)	73
Adjusted EBITDA from discontinued operations	223	199	24
Segment Adjusted EBITDA	$ 732	$ 665	$ 67

The Investment in Sunoco LP segment reflects the consolidated results of Sunoco LP.

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA related to the Investment in Sunoco LP segment increased due to the net impacts of the following:

- an increase of $18 million in gross margin (excluding a $65 million change in fair value adjustments related to inventory and unrealized gains and losses on commodity risk management activities) primarily caused by an increase in wholesale motor fuel gross profit per gallon, partially offset by a net increase in other gross profit consisting of merchandise, rental & other and retail motor fuel of $13 million;
- a decrease of $27 million in general and administrative expenses primarily due to higher costs in 2016 related to relocation, employee termination, and higher contract labor and professional fees as the Partnership transitioned offices in Philadelphia, Pennsylvania, Houston, Texas, and Corpus Christi, Texas to Dallas during 2016; and
- an increase of $24 million related to discontinued operations; partially offset by
- an increase of $1 million in other operating expenses primarily attributable to Sunoco LP’s retail business which has expanded through third-party acquisitions as well as through the construction of new-to-industry sites.

All Other

	Years Ended December 31,		
	2017	2016	Change
Revenue	$ 2,901	$ 3,272	$ (371)
Cost of products sold	2,509	2,942	(433)
Segment margin	392	330	62
Unrealized (gains) losses on commodity risk management activities	(11)	26	(37)
Operating expenses, excluding non-cash compensation expense	(117)	(79)	(38)
Selling, general and administrative expenses, excluding non-cash compensation expense	(135)	(182)	47
Adjusted EBITDA related to unconsolidated affiliates	45	15	30
Other and eliminations	13	(13)	26
Segment Adjusted EBITDA	$ 187	$ 97	$ 90

Amounts reflected in our all other segment primarily include:

- our natural gas marketing operations;
- our wholly-owned natural gas compression operations;
- a non-controlling interest in PES, representing approximately 33% of PES' outstanding common units for the periods presented above; and
- our investment in coal handling facilities.

Segment Adjusted EBITDA. For the year ended December 31, 2017 compared to the prior year, Segment Adjusted EBITDA increased due to the net impact of the following:

- a decrease of $47 million in selling, general and administrative expenses primarily due to the settlement of a contingent matter in the prior year;
- an increase of $33 million in Adjusted EBITDA related to our investment in PES;
- an increase of $20 million in crude and power trading activates, primarily from the liquidation of crude inventories;
- a one-time fee of $15 million received from a joint venture affiliate; and
- a decrease of $11 million in expenses related to our compression business; partially offset by
- a decrease of $31 million from the mark-to-market of physical system gas and settled derivatives.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Parent Company Only

Subsequent to the Merger, substantially all of the Partnership's cash flows are derived from distributions related to its investment in ETO, whose cash flows are derived from its subsidiaries, including ETO's investments in Sunoco LP and USAC.

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

The Parent Company expects ETO and its respective subsidiaries and investments in Sunoco LP and USAC to utilize their resources, along with cash from their operations, to fund their announced growth capital expenditures and working capital needs; however, the Parent Company may issue debt or equity securities from time to time, as it deems prudent to provide liquidity for new capital projects of its subsidiaries or for other partnership purposes.

ETO

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

ETO currently expects capital expenditures in 2019 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 125	$ 175	$ 35	$ 40
Interstate transportation and storage [(1)]	175	200	140	145
Midstream	750	850	115	120
NGL and refined products transportation and services	3,100	3,200	90	100
Crude oil transportation and services [(1)]	575	650	90	100
All other (including eliminations)	125	150	50	55
Total capital expenditures	$ 4,850	$ 5,225	$ 520	$ 560

(1) Includes capital expenditures related to ETO's proportionate ownership of the Bakken, Rover and Bayou Bridge pipeline projects.

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

ETO generally funds maintenance capital expenditures and distributions with cash flows from operating activities. ETO generally expects to funds growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional preferred units or a combination thereof.

As of December 31, 2018, in addition to $418 million of cash on hand, ETO had available capacity under the ETO Credit Facilities of $2.24 billion. Based on ETO's current estimates, ETO expects to utilize capacity under the ETO Credit Facilities, along with cash from operations, to fund ETO's announced growth capital expenditures and working capital needs through the end of 2019; however, ETO may issue debt or equity securities prior to that time as ETO deems prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Sunoco LP

Sunoco LP's primary sources of liquidity consist of cash generated from operating activities, borrowings under its $1.50 billion credit facility and the issuance of additional long-term debt or partnership units as appropriate given market conditions. At December 31, 2018, Sunoco LP had available borrowing capacity of $792 million under its revolving credit facility and $56 million of cash and cash equivalents on hand.

In 2019, Sunoco LP expects to invest approximately $90 million in growth capital expenditures and approximately $45 million on maintenance capital expenditures. Sunoco LP may revise the timing of these expenditures as necessary to adapt to economic conditions.

USAC

The compression services business is capital intensive, requiring significant investment to maintain, expand and upgrade existing operations. USAC's capital requirements have consisted primarily of, and it anticipates that its capital requirements will continue to consist primarily of, the following:

- maintenance capital expenditures, which are capital expenditures made to maintain the operating capacity of its assets and extend their useful lives, to replace partially or fully depreciated assets, or other capital expenditures that are incurred in maintaining its existing business and related operating income; and

- expansion capital expenditures, which are capital expenditures made to expand the operating capacity or operating income capacity of assets, including by acquisition of compression units or through modification of existing compression units to increase their capacity, or to replace certain partially or fully depreciated assets that were not currently generating operating income.

USAC classifies capital expenditures as maintenance or expansion on an individual asset basis. Over the long-term, USAC expects that its maintenance capital expenditure requirements will continue to increase as the overall size and age of its fleet increase. USAC currently plans to spend approximately $25 million in maintenance capital expenditures during 2019, including parts consumed from inventory.

Without giving effect to any equipment USAC may acquire pursuant to any future acquisitions, it currently has budgeted between $140 million and $150 million in expansion capital expenditures during 2019. As of December 31, 2018, USAC has binding commitments to purchase $108 million of additional compression units and serialized parts, all of which USAC expects to be delivered in 2019.

Cash Flows

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

Operating Activities

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

Following is a summary of operating activities by period:

Year Ended December 31, 2018

Cash provided by operating activities in 2018 was $7.51 billion and income from continuing operations was $3.63 billion. The difference between net income and cash provided by operating activities in 2018 primarily consisted of net non-cash items totaling $3.30 billion and changes in operating assets and liabilities of $289 million. The non-cash activity in 2018 consisted primarily of depreciation, depletion and amortization of $2.86 billion, impairment losses of $431 million, deferred income tax benefit of $7 million, inventory valuation adjustments of $85 million, losses on extinguishments of debt of $112 million, equity in earnings of unconsolidated affiliates of $344 million and non-cash compensation expense of $105 million. The Partnership also received distributions of $328 million from unconsolidated affiliates.

Year Ended December 31, 2017

Cash provided by operating activities in 2017 was $4.43 billion and income from continuing operations was $2.54 billion. The difference between net income and cash provided by operating activities in 2017 primarily consisted of net non-cash items totaling $1.82 billion and changes in operating assets and liabilities of $192 million. The non-cash activity in 2017 consisted primarily of depreciation, depletion and amortization of $2.55 billion, impairment losses of $1.35 billion, deferred income tax benefit of $1.87 billion, inventory valuation adjustments of $24 million, losses on extinguishments of debt of $89 million, equity in earnings of unconsolidated affiliates of $144 million, and non-cash compensation expense of $99 million. The Partnership also received distributions of $297 million from unconsolidated affiliates.

Year Ended December 31, 2016

Cash provided by operating activities in 2016 was $3.32 billion and income from continuing operations was $462 million. The difference between net income and cash provided by operating activities in 2016 primarily consisted of net non-cash items totaling $2.80 billion and changes in operating assets and liabilities of $179 million. The non-cash activity in 2016 consisted primarily of depreciation, depletion and amortization of $2.22 billion, impairment losses of $1.35 billion, deferred income tax benefit of $177 million, inventory valuation adjustments of $97 million, equity in earnings of unconsolidated affiliates of $270 million, gains on acquisitions of $83 million and non-cash compensation expense of $70 million. The Partnership also received distributions of $268 million from unconsolidated affiliates.

Investing Activities

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

Following is a summary of investing activities by period:

Year Ended December 31, 2018

Cash used in investing activities in 2018 of $7.08 billion was comprised primarily of capital expenditures of $7.30 billion (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs). We recorded a net increase in cash of $461 million related to the USAC acquisition. We paid net cash for acquisitions of $429 million.

Year Ended December 31, 2017

Cash used in investing activities in 2017 of $5.61 billion was comprised primarily of capital expenditures of $8.41 billion (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs). We paid net cash for acquisitions of $583 million, including the acquisition of PennTex noncontrolling interest. We received $3.48 billion in proceeds from sale of interests in Bakken Pipeline and Rover Pipeline.

Year Ended December 31, 2016

Cash used in investing activities in 2016 of $8.98 billion was comprised primarily of capital expenditures of $7.70 billion (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs). We paid net cash for acquisitions of $1.40 billion.

The following is a summary of the Partnership's capital expenditures (including only our proportionate share of the Bakken, Rover and Bayou Bridge pipeline projects and net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Year Ended December 31, 2018:			
Intrastate transportation and storage	$ 311	$ 33	$ 344
Interstate transportation and storage	695	117	812
Midstream	1,026	135	1,161
NGL and refined products transportation and services	2,303	78	2,381
Crude oil transportation and services	414	60	474
Investment in Sunoco LP	72	31	103
Investment in USAC (1)	182	23	205
All other (including eliminations)	117	33	150
Total capital expenditures	$ 5,120	$ 510	$ 5,630
Year Ended December 31, 2017:			
Intrastate transportation and storage	$ 155	$ 20	$ 175
Interstate transportation and storage	645	83	728
Midstream	1,185	123	1,308
NGL and refined products transportation and services	2,899	72	2,971
Crude oil transportation and services	392	61	453
Investment in Sunoco LP (2)	129	48	177
All other (including eliminations)	196	72	268
Total capital expenditures	$ 5,601	$ 479	$ 6,080
Year Ended December 31, 2016:			
Intrastate transportation and storage	$ 53	$ 23	$ 76
Interstate transportation and storage	191	89	280
Midstream	1,133	122	1,255
NGL and refined products transportation and services	2,150	48	2,198
Crude oil transportation and services	1,806	35	1,841
Investment in Sunoco LP (2)	333	106	439
All other (including eliminations)	109	51	160
Total capital expenditures	$ 5,775	$ 474	$ 6,249

(1) Amounts related to USAC capital expenditures (net of contributions in aid of construction costs) for 2018 are subsequent to the close of the CDM Contribution on April 2, 2018 as discussed in "Recent Developments."

(2) Amounts related to Sunoco LP's capital expenditures include capital expenditures related to discontinued operations.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund acquisitions and growth capital expenditures. Distributions increase between the periods based on increases in the number of common units outstanding or increases in the distribution rate.

Following is a summary of financing activities by period:

Year Ended December 31, 2018

Cash used in financing activities was $3.08 billion in 2018. We had a consolidated increase in our debt level of $53 million, primarily due to the issuance of Parent Company and subsidiary senior notes. Our subsidiaries also received $1.40 billion in proceeds from common unit offerings, including $58 million from the issuance of ETO Common Units and $1.34 billion from the issuance of other subsidiary common units. We paid distributions to partners of $1.68 billion, and our subsidiaries paid $3.12 billion on limited partner interests other than those held by the Parent Company. In addition, we received capital contributions from noncontrolling interests of $649 million.

Year Ended December 31, 2017

Cash provided by financing activities was $953 million in 2017. We had a consolidated increase in our debt level of $340 million, primarily due to the issuance of Parent Company and subsidiary senior notes. Our subsidiaries also received $3.24 billion in proceeds from common unit offerings, including $2.28 billion from the issuance of ETO Common Units and $952 million from the issuance of other subsidiary common units. We paid distributions to partners of $1.01 billion, and our subsidiaries paid $2.96 billion on limited partner interests other than those held by the Parent Company. In addition, we received capital contributions from noncontrolling interests of $1.21 billion.

Year Ended December 31, 2016

Cash provided by financing activities was $5.93 billion in 2016. We had a consolidated increase in our debt level of $6.71 billion, primarily due to the issuance of Parent Company and subsidiary senior notes. Our subsidiaries also received $2.56 billion in proceeds from common unit offerings, including $1.10 billion from the issuance of ETO Common Units and $1.46 billion from the issuance of other subsidiary common units. We paid distributions to partners of $1.02 billion, and our subsidiaries paid $2.77 billion on limited partner interests other than those held by the Parent Company. In addition, we received capital contributions from noncontrolling interests of $236 million.

Discontinued Operations

Following is a summary of activities related to discontinued operations by period:

Year Ended December 31, 2018

Cash provided by discontinued operations was $2.73 billion for the year ended December 31, 2018 resulting from cash used in operating activities of $484 million, cash provided by investing activities of $3.21 billion and changes in cash included in current assets held for sale of $11 million.

Year Ended December 31, 2017

Cash provided by discontinued operations was $93 million for the year ended December 31, 2017 resulting from cash provided by operating activities of $136 million, cash used in investing activities of $38 million and changes in cash included in current assets held for sale of $5 million.

Year Ended December 31, 2016

Cash used in discontinued operations was $385 million for the year ended December 31, 2016 resulting from cash provided by operating activities of $93 million, cash used in investing activities of $483 million and changes in cash included in current assets held for sale of $5 million.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31, 2018	December 31, 2017
Parent Company Indebtedness:		
ET Senior Notes due October 2020	$ 1,187	$ 1,187
ET Senior Notes due March 2023	1,000	1,000
ET Senior Notes due January 2024	1,150	1,150
ET Senior Notes due June 2027	1,000	1,000
ET Senior Secured Term Loan	1,220	1,220
ET Senior Secured Revolving Credit Facility	—	1,188
Subsidiary Indebtedness:		
ETO Senior Notes	28,755	27,005
Transwestern Senior Notes	575	575
Panhandle Senior Notes	385	785
Sunoco LP Senior Notes, Term Loan and lease-related obligations	2,307	3,556
USAC Senior Notes due April 1, 2026	725	—
Credit Facilities and Commercial Paper:		
ETO $1.00 billion 364-Day Credit Facility due November 2019	—	50
ETO $5.00 billion Revolving Credit Facility due December 2023	3,694	2,292
Sunoco LP $1.50 billion Revolving Credit Facility due September 2019	—	765
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	700	—
USAC $1.60 billion Revolving Credit Facility due April 2023	1,050	—
Bakken $2.50 billion Credit Facility due August 2019	2,500	2,500
Other long-term debt	7	8
Unamortized premiums, net of discounts and fair value adjustments	21	50
Deferred debt issuance costs	(248)	(247)
Total debt	46,028	44,084
Less: current maturities of long-term debt	2,655	413
Long-term debt, less current maturities	$ 43,373	$ 43,671

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

Recent Transactions

ET Revolving Credit Facility

In connection with the Energy Transfer Merger in October 2018, ET repaid in full all outstanding borrowings under the ET Senior Secured Revolving Credit Facility and the facility was terminated.

Energy Transfer LP Senior Notes Offering

In October 2017, ET issued $1 billion aggregate principal amount of 4.25% senior notes due 2023. The $990 million net proceeds from the offering were used to repay a portion of the outstanding indebtedness under its term loan facility and for general partnership purposes.

ET Term Loan Facility

On January 15, 2019, Energy Transfer LP paid in full all outstanding borrowings under its Senior Secured Term Loan Agreement and thereafter terminated the term loan agreement. In connection with the termination of the term loan agreement, the collateral securing certain series of the Partnership's outstanding senior notes was released in accordance with the terms of the applicable indentures governing such senior notes.

ETO 2019 Senior Notes Offering and Redemption

In January 2019, ETO issued the following senior notes:

- $750 million aggregate principal amount of 4.50% senior notes due 2024;
- $1.50 billion aggregate principal amount of 5.25% senior notes due 2029; and
- $1.75 billion aggregate principal amount of 6.25% senior notes due 2049.

The $3.96 billion net proceeds from the offering were used to make an intercompany loan to ET (which ET used to repay its term loan in full), for general partnership purposes and to redeem at maturity all of the following:

- ETO's $400 million aggregate principal amount of 9.70% senior notes due March 15, 2019;
- ETO's $450 million aggregate principal amount of 9.00% senior notes due April 15, 2019; and
- Panhandle's $150 million aggregate principal amount of 8.125% senior notes due June 1, 2019.

ETO 2018 Senior Notes Offering and Redemption

In June 2018, ETO issued the following senior notes:

- $500 million aggregate principal amount of 4.20% senior notes due 2023;
- $1.00 billion aggregate principal amount of 4.95% senior notes due 2028;
- $500 million aggregate principal amount of 5.80% senior notes due 2038; and
- $1.00 billion aggregate principal amount of 6.00% senior notes due 2048.

The $2.96 billion net proceeds from the offering were used to repay borrowings outstanding under ETO's revolving credit facility, for general partnership purposes and to redeem at maturity all of the following senior notes:

- ETO's $650 million aggregate principal amount of 2.50% senior notes due June 15, 2018;
- Panhandle's $400 million aggregate principal amount of 7.00% senior notes due June 15, 2018; and
- ETO's $600 million aggregate principal amount of 6.70% senior notes due July 1, 2018.

The aggregate amount paid to redeem these notes was approximately $1.65 billion.

Sunoco LP Senior Notes Offering

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028. Sunoco LP used the proceeds from the private offering, along with proceeds from its retail divestment to:

- redeem in full its existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020 and $800 million in aggregate principal amount of 6.375% senior notes due 2023;
- repay in full and terminate its term loan;
- pay all closing costs in connection with its retail divestment;
- redeem the outstanding Sunoco LP Series A Preferred Units; and
- repurchase 17,286,859 Sunoco LP common units owned by ETO.

On December 3, 2018, Sunoco LP completed an exchange of the notes for registered notes with substantially identical terms.

USAC Senior Notes Offerings

In March 2018, USAC completed a private offering of $725 million aggregate principal amount of senior notes that mature on April 1, 2026. The notes accrue interest from March 23, 2018 at the rate of 6.875% per year. Interest on the notes will be payable semi-annually in arrears on each April 1 and October 1, commencing on October 1, 2018. On January 14, 2019, USAC completed an exchange of these notes for registered notes with substantially identical terms.

In February 2019, USAC announced the offering of $750 million aggregate principal amount of senior unsecured notes due 2027 in a private placement to eligible purchasers. USAC intends to use the net proceeds from this offering to repay a portion of its existing borrowings under the USAC credit facility and for general partnership purposes.

Credit Facilities and Commercial Paper

Parent Company Credit Facility

In connection with the closing of the Energy Transfer Merger, on October 19, 2018, the Partnership repaid in full all outstanding borrowings under the facility and the facility was terminated.

ETO Credit Facilities

Borrowings under the ETO Credit Facilities are unsecured and initially guaranteed by Sunoco Logistics Partners Operations L.P. Borrowings under the ETO Credit Facilities will bear interest at a eurodollar rate or a base rate, at our option, plus an applicable margin. In addition, we will be required to pay a quarterly commitment fee to each lender equal to the product of the applicable rate and such lender's applicable percentage of the unused portion of the aggregate commitments under the ETO Credit Facilities.

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

ETO's revolving credit facility (the "ETO Five-Year Credit Facility") previously allowed for unsecured borrowings up to $4.00 billion and matured in December 2022. On October 19, 2018, the ETO Five-Year Credit Facility was amended to increase the borrowing capacity by $1.00 billion, to $5.00 billion, and to extend the maturity date to December 1, 2023. The ETO Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $6.00 billion under certain conditions.

As of December 31, 2018, the ETO Five-Year Credit Facility had $3.69 billion outstanding, of which $2.34 billion was commercial paper. The amount available for future borrowings was $1.24 billion after taking into account letters of credit of $63 million. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 3.57%.

ETO's 364-day revolving credit facility (the "ETO 364-Day Facility") previously allowed for unsecured borrowings up to $1.00 billion and matured on November 30, 2018. On October 19, 2018, the ETO 364-Day Facility was amended to extend the maturity date to November 29, 2019. As of December 31, 2018, the ETO 364-Day Facility had no outstanding borrowings.

Bakken Credit Facility

In August 2016, ETO and Phillips 66 completed project-level financing of the Bakken pipeline. The $2.50 billion credit facility matures in August 2019 (the "Bakken Credit Facility"). As of December 31, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings, all of which has been reflected in current maturities of long-term debt on the Partnership's consolidated balance sheet included in "Item 8. Financial Statements and Supplementary Data." The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.27%.

Sunoco LP Credit Facility

As of December 31, 2018, the Sunoco LP Credit Facility had $700 million outstanding borrowings and $8 million in standby letters of credit. The unused availability on the revolver at December 31, 2018 was $792 million. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.45%.

USAC Credit Facility

As of December 31, 2018, USAC had $1.05 billion of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2018, USAC had $550 million of availability under its credit facility. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.69%.

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

The Term Loan Facility and ET Revolving Credit Facility previously contained customary representations, warranties, covenants, and events of default, including a change of control event of default and limitations on incurrence of liens, new lines of business, merger, transactions with affiliates and restrictive agreements. Both facilities have been paid off and terminated.

Covenants Related to ETO

The agreements relating to the ETO 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 ETO Credit Facilities 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 ETO Credit Facilities) during certain Defaults (as defined in the ETO Credit Facilities) and during any Event of Default (as defined in the ETO Credit Facilities);
- 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 ETO Credit Facilities applicable margin and rate used in connection with the interest rates and commitment fees, respectively, are based on the credit ratings assigned to our senior, unsecured, non-credit enhanced long-term debt. The applicable margin for eurodollar rate loans under the ETO Five-Year Facility ranges from 1.125% to 2.000% and the applicable margin for base rate loans ranges from 0.125% to 1.000%. The applicable rate for commitment fees under the ETO Five-Year Facility ranges from 0.125% to 0.300%. The applicable margin for eurodollar rate loans under the ETO 364-Day Facility ranges from 1.125% to 1.750% and the applicable margin for base rate loans ranges from 0.250% to 0.750%. The applicable rate for commitment fees under the ETO 364-Day Facility ranges from 0.125% to 0.225%.

The ETO Credit Facilities contain various covenants including limitations on the creation of indebtedness and liens, and related to the operation and conduct of our business. The ETO Credit Facilities also limit us, on a rolling four quarter basis, to a maximum Consolidated Funded Indebtedness to Consolidated EBITDA ratio, as defined in the underlying credit agreements, of 5.0 to 1, which can generally be increased to 5.5 to 1 during a Specified Acquisition Period. Our Leverage Ratio was 3.38 to 1 at December 31, 2018, as calculated in accordance with the credit agreements.

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 Partnership's or our subsidiaries' ability to incur additional debt and/or our ability to pay distributions to Unitholders.

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 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 Sunoco LP

The Sunoco LP Credit Facility contains various customary representations, warranties, covenants and events of default, including a change of control event of default, as defined therein. Sunoco LP's Credit Facility requires Sunoco LP to maintain a Net Leverage Ratio of not more than 5.5 to 1. The maximum Net Leverage Ratio is subject to upwards adjustment of not more than 6.0 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in certain specified acquisitions of not less than $50 million (as permitted under Sunoco LP's Credit Facility agreement). The Sunoco LP Credit Facility also requires Sunoco LP to maintain an Interest Coverage Ratio (as defined in the Sunoco LP's Credit Facility agreement) of not less than 2.25 to 1.

Covenants Related to USAC

The USAC Credit Facility contains covenants that limit (subject to certain exceptions) USAC's ability to, among other things:

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- merge or consolidate;
- sell our assets; or
- make certain acquisitions.

The credit facility is also subject to the following financial covenants, including covenants requiring us to maintain:

- a minimum EBITDA to interest coverage ratio of 2.5 to 1.0, determined as of the last day of each fiscal quarter; and

- a maximum funded debt to EBITDA ratio, determined as of the last day of each fiscal quarter, for the annualized trailing three months of (i) 5.75 to 1 through the end of the fiscal quarter ending March 31, 2019, (ii) 5.5 to 1 through the end of the fiscal quarter ending December 31, 2019 and (iii) 5.0 to 1 thereafter, in each case subject to a provision for increases to such thresholds by 0.50 in connection with certain future acquisitions for the six consecutive month period following the period in which any such acquisition occurs.

Compliance with our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2018.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2018:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 46,255	$ 3,505	$ 4,474	$ 12,760	$ 25,516
Interest on long-term debt[1]	27,190	2,311	4,188	3,462	17,229
Payments on derivatives	181	76	105	—	—
Purchase commitments[2]	2,458	2,295	121	22	20
Transportation, natural gas storage and fractionation contracts	9	8	1	—	—
Operating lease obligations	601	104	169	108	220
Service concession arrangement[3]	394	15	30	31	318
Other[4]	198	26	51	43	78
Total[5]	$ 77,286	$ 8,340	$ 9,139	$ 16,426	$ 43,381

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2018. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2018. To the extent interest rates change, our contractual obligation for interest payments will change. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for further discussion.

(2) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for refined product and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the December 31, 2018 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated.

(3) Includes minimum guaranteed payments under service concession arrangements with New Jersey Turnpike Authority and New York Thruway Authority.

(4) Expected contributions to fund our pension and postretirement benefit plans were included in "Other" above. Environmental liabilities, asset retirement obligations, unrecognized tax benefits, contingency accruals and deferred revenue, which were included in "Other non-current liabilities" in our consolidated balance sheets were excluded from the table above as the amounts do not represent contractual obligations or, in some cases, the amount and/or timing of the cash payments is uncertain.

(5) Excludes net non-current deferred tax liabilities of $2.93 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Cash Distributions Paid by the Parent Company

Under the Parent Company Partnership Agreement, the Parent Company will distribute all of its Available Cash, as defined, within 50 days following the end of each fiscal quarter. Available cash generally means, with respect to any quarter, all cash on hand at the end of such quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner that is necessary or appropriate to provide for future cash requirements.

Distributions declared and paid during the periods presented are as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 4, 2016	February 19, 2016	$ 0.2850
March 31, 2016 (1)	May 6, 2016	May 19, 2016	0.2850
June 30, 2016 (1)	August 8, 2016	August 19, 2016	0.2850
September 30, 2016 (1)	November 7, 2016	November 18, 2016	0.2850
December 31, 2016 (1)	February 7, 2017	February 21, 2017	0.2850
March 31, 2017	May 10, 2017	May 19, 2017	0.2850
June 30, 2017	August 7, 2017	August 21, 2017	0.2850
September 30, 2017	November 7, 2017	November 20, 2017	0.2950
December 31, 2017	February 8, 2018	February 20, 2018	0.3050
March 31, 2018	May 7, 2018	May 21, 2018	0.3050
June 30, 2018	August 6, 2018	August 20, 2018	0.3050
September 30, 2018	November 8, 2018	November 19, 2018	0.3050
December 31, 2018	February 8, 2019	February 19, 2019	0.3050

(1) Certain common unitholders elected to participate in a plan pursuant to which those unitholders elected to forego their cash distributions on all or a portion of their common units for a period of up to nine quarters commencing with the distribution for the quarter ended March 31, 2016 and, in lieu of receiving cash distributions on these common units for each such quarter, each said unitholder received Convertible Units (on a one-for-one basis for each common unit as to which the participating unitholder elected be subject to this plan) that entitled them to receive a cash distribution of up to $0.11 per Convertible Unit. See Note 8 to the Partnership's consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

Our distributions declared and paid with respect to our Convertible Unit during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2016	May 6, 2016	May 19, 2016	$ 0.1100
June 30, 2016	August 8, 2016	August 19, 2016	0.1100
September 30, 2016	November 7, 2016	November 18, 2016	0.1100
December 31, 2016	February 7, 2017	February 21, 2017	0.1100
March 31, 2017	May 10, 2017	May 19, 2017	0.1100
June 30, 2017	August 7, 2017	August 21, 2017	0.1100
September 30, 2017	November 7, 2017	November 20, 2017	0.1100
December 31, 2017	February 8, 2018	February 20, 2018	0.1100
March 31, 2018	May 7, 2018	May 21, 2018	0.1100

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

	Years Ended December 31,		
	2018 (1)	2017	2016
Limited Partners	$ 2,215	$ 1,022	$ 971
General Partner interest	3	3	3
Total Parent Company distributions	$ 2,218	$ 1,025	$ 974

(1) Include distributions declared by Energy Transfer LP for periods subsequent to the Energy Transfer Merger.

The total amounts of distributions declared and paid during the periods presented prior to the closing of the Energy Transfer Merger as discussed in Note 1 (all from Available Cash from ETO's operating surplus and are shown in the period to which they relate) are as follows:

	Years Ended December 31,			
	ETO			Sunoco Logistics
	2018	2017	2016	2016
Common Units held by public	$ 1,286	$ 2,435	$ 2,168	$ 485
Common Units held by ETO	—	—	—	135
Common Units held by ET	31	61	28	—
Class H Units held by ET	—	—	357	—
General Partner interest and IDRs	900	1,654	1,395	412
IDR relinquishments (1)	(84)	(656)	(409)	(15)
Series A Preferred Units	59	15	—	—
Series B Preferred Units	36	9	—	—
Series C Preferred Units (2)	23	—	—	—
Series D Preferred Units (2)	15	—	—	—
Total distributions declared to partners	$ 2,266	$ 3,518	$ 3,539	$ 1,017

(1) Net of Class I unit distributions

(2) Distributions reflect prorated distributions for the year ended December 31, 2018.

Cash Distributions Paid by Subsidiaries

Certain of our subsidiaries are required by their respective partnership agreements to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by the board of directors of their respective general partners.

ETO Preferred Unit Distributions

Distributions on the Partnership's Series A, Series B, Series C and Series D preferred units declared and/or paid by the Partnership during the periods presented were as follows:

Period Ended	Record Date	Payment Date	Series A (1)	Series B (1)	Series C	Series D
December 31, 2017	February 1, 2018	February 15, 2018	$ 15.4510 *	$ 16.3780 *	$ —	$ —
June 30, 2018	August 1, 2018	August 15, 2018	31.2500	33.1250	0.5634 *	—
September 30, 2018	November 1, 2018	November 15, 2018	—	—	0.4609	0.5931 *
December 31, 2018	February 1, 2019	February 15, 2019	31.2500	33.1250	0.4609	0.4766

* Represent prorated initial distributions.
(1) Series A and Series B preferred unit distributions are paid on a bi-annual basis.

Sunoco LP Cash Distributions

The following table illustrates the percentage allocations of available cash from operating surplus between Sunoco LP's common unitholders and the holder of its IDRs based on the specified target distribution levels, after the payment of distributions to Class C unitholders. The amounts set forth under "marginal percentage interest in distributions" are the percentage interests of the IDR holder and the common unitholders in any available cash from operating surplus which Sunoco LP distributes up to and including the corresponding amount in the column "total quarterly distribution per unit target amount." The percentage interests shown for common unitholders and IDR holder for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Common Unitholders	Holder of IDRs
Minimum Quarterly Distribution	$0.4375	100%	—%
First Target Distribution	$0.4375 to $0.503125	100%	—%
Second Target Distribution	$0.503125 to $0.546875	85%	15%
Third Target Distribution	$0.546875 to $0.656250	75%	25%
Thereafter	Above $0.656250	50%	50%

Distributions on Sunoco LP's units declared and/or paid by Sunoco LP were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 5, 2016	February 16, 2016	$ 0.8013
March 31, 2016	May 6, 2016	May 16, 2016	0.8173
June 30, 2016	August 5, 2016	August 15, 2016	0.8255
September 30, 2016	November 7, 2016	November 15, 2016	0.8255
December 31, 2016	February 13, 2017	February 21, 2017	0.8255
March 31, 2017	May 9, 2017	May 16, 2017	0.8255
June 30, 2017	August 7, 2017	August 15, 2017	0.8255
September 30, 2017	November 7, 2017	November 14, 2017	0.8255
December 31, 2017	February 6, 2018	February 14, 2018	0.8255
March 31, 2018	May 7, 2018	May 15, 2018	0.8255
June 30, 2018	August 7, 2018	August 15, 2018	0.8255
September 30, 2018	November 6, 2018	November 14, 2018	0.8255
December 31, 2018	February 6, 2019	February 14, 2019	0.8255

The total amount of distributions to the Partnership from Sunoco LP for the periods presented below is as follows:

	Years Ended December 31,		
	2018	2017	2016
Distributions from Sunoco LP			
Limited Partner interests	$ 94	$ 150	$ 151
General Partner interest and IDRs	70	85	81
Series A Preferred	2	23	—
Total distributions from Sunoco LP	$ 166	$ 258	$ 232

USAC Cash Distributions

Subsequent to the Energy Transfer Merger and USAC Transactions described in Note 1 and Note 3, respectively, ETO owns approximately 39.7 million USAC common units and 6.4 million USAC Class B units. As of December 31, 2018, USAC had approximately 96.4 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding incentive distribution rights.

Distributions on USAC's units declared and/or paid by USAC subsequent to the USAC transaction on April 2, 2018 were as follows:

Quarter Ended	Record Date	Payment Date	Rate	
March 31, 2018	May 1, 2018	May 11, 2018	$	0.5250
June 30, 2018	July 30, 2018	August 10, 2018		0.5250
September 30, 2018	October 29, 2018	November 09, 2018		0.5250
December 31, 2018	January 28, 2019	February 8, 2019		0.5250

The total amount of distributions to the Partnership from USAC for the periods presented below is as follows:

	Years Ended December 31,		
	2018	2017	2016
Distributions from USAC			
Limited Partner interests	$ 73	$ —	$ —
Total distributions from USAC	$ 73	$ —	$ —

Recent Accounting Pronouncements

ASU 2014-09

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. The Partnership adopted ASU 2014-09 on January 1, 2018.

Upon the adoption of ASU 2014-09, the amount of revenue that the Partnership recognizes on certain contracts has changed, primarily due to decreases in revenue (with offsetting decreases to cost of sales) resulting from recognition of non-cash consideration as revenue when received and as cost of sales when sold to third parties. In addition, income statement reclassifications were required for fuel usage and loss allowances related to multiple segments as well as contracts deemed to be in-substance supply agreements in our midstream segment. In addition to the evaluation performed, we have made appropriate design and implementation updates to our business processes, systems and internal controls to support recognition and disclosure under the new standard.

Utilizing the practical expedients allowed under the modified retrospective adoption method, Accounting Standards Codification ("ASC") Topic 606 was only applied to existing contracts for which the Partnership has remaining performance obligations as of January 1, 2018, and new contracts entered into after January 1, 2018. ASC Topic 606 was not applied to contracts that were completed prior to January 1, 2018.

The Partnership has elected to apply the modified retrospective method to adopt the new standard. For contracts in scope of the new revenue standard as of January 1, 2018, the cumulative effect adjustment to partners' capital was not material. The comparative information has not been restated under the modified retrospective method and continues to be reported under the accounting standards in effect for those periods.

ASU 2016-02

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 information about the amount, timing, and uncertainty of cash flows arising from a lease. The update requires lessees to record virtually all leases on their balance sheets. For lessors, this amended guidance modifies the classification criteria and the accounting for sales-type and direct financing leases. In January 2018, the FASB issued Accounting Standards Update No. 2018-01 ("ASU 2018-01"), which provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the existing lease guidance. The Partnership plans to elect the package of transition practical expedients and will adopt this standard beginning with its first quarter of fiscal 2019 and apply it retrospectively at the beginning of the period of adoption through a cumulative-effect adjustment to retained earnings. The Partnership has performed several procedures to evaluate the impact of the adoption of this standard on the financial statements and disclosures and address the implications of Topic 842 on future lease arrangements. The procedures include reviewing all forms of leases, performing a completeness assessment over the lease population, establishing processes and controls to timely identify new and modified lease agreements, educating its employees on these new processes and controls and implementing a third-party supported lease accounting information system to account for our leases in accordance with the new standard. The Partnership is finalizing its evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements, and estimates approximately $1.0 billion of right-to-use assets and lease liabilities will be recognized in the consolidated balance sheet upon adoption, with no material impact to its consolidated statements of operations.

ASU 2017-12

In August 2017, the FASB issued Accounting Standards Update No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.* The amendments in this update improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition, the amendments in this update make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP. This ASU is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. The Partnership expects to adopt the new rules in the first quarter of 2019 and does not expect the adoption of the new accounting rules to have a material impact on the consolidated financial statements and related disclosures.

ASU 2018-02

In February 2018, the FASB issued Accounting Standards Update No. 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*, which allows a reclassification from accumulated other comprehensive income to partners' capital for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. The Partnership elected to early adopt this ASU in the first quarter of 2018. The effect of the adoption was not material.

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, 2018 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.

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

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.

Investment in Sunoco LP

Sunoco LP’s revenues from motor fuel are recognized either at the time fuel is delivered to the customer or at the time of sale. Shipment and delivery of motor fuel generally occurs on the same day. Sunoco LP charges wholesale customers for third-party transportation costs, which are recorded net in cost of sales. Through PropCo, Sunoco LP’s wholly-owned corporate subsidiary, Sunoco LP may sell motor fuel to customers on a commission agent basis, in which Sunoco LP retains title to inventory, controls access to and sale of fuel inventory, and recognizes revenue at the time the fuel is sold to the ultimate customer. In Sunoco LP’s fuel distribution and marketing operations, Sunoco LP derives other income from rental income, propane and lubricating oils, and other ancillary product and service offerings. In Sunoco LP’s other operations, Sunoco LP derives other income from merchandise, lottery ticket sales, money orders, prepaid phone cards and wireless services, ATM transactions, car washes, movie rentals, and other ancillary product and service offerings. Sunoco LP records revenue from other retail transactions on a net commission basis when a product is sold and/or services are rendered.

Investment in USAC

USAC’s revenue from contracted compression, station, gas treating and maintenance services is recognized ratably under its fixed-fee contracts over the term of the contract as services are provided to its customers. Initial contract terms typically range from six months to five years. However, USAC usually continues to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. USAC primarily enters into fixed-fee contracts whereby its customers are required to pay its monthly fee even during periods of limited or disrupted throughput. Services are generally billed monthly, one month in advance of the commencement of the service month, except for certain customers who are billed at the beginning of the service month, and payment is generally due 30 days after receipt of the invoice. Amounts invoiced in advance are recorded as deferred revenue until earned, at which time they are recognized as revenue. The amount of consideration USAC receives and revenue it recognizes is based upon the fixed fee rate stated in each service contract.

USAC’s retail parts and services revenue is earned primarily on freight and crane charges that are directly reimbursable by its customers and maintenance work on units at its customers’ locations that are outside the scope of USAC’s core maintenance activities. Revenue from retail parts and services is recognized at the point in time the part is transferred or service is provided and control is transferred to the customer. At such time, the customer has the ability to direct the use of the benefits of such part or service after USAC has performed its services. USAC bills upon completion of the service or transfer of the parts, and payment is generally due 30 days after receipt of the invoice. The amount of consideration USAC receives and revenue it recognizes is based upon the invoice amount.

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 assessed and potentially 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 OTC commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL, crude oil and refined products. These contracts consist primarily of futures and swaps.

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, Goodwill, Intangible Assets and Investments in Unconsolidated Affiliates. 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 of an investment in an unconsolidated affiliate is recognized when circumstances indicate that a decline in the investment value is other than temporary. 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 an 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. Such changes in fair value estimates could result in additional impairments in future periods; 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, resulting in additional impairments.

Management does not believe that any of the goodwill balances in its reporting units is currently at significant risk of impairment; however, of the $4.89 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2018, approximately $650 million is recorded in reporting units for which the estimated fair value exceeded the carrying value by less than 20% in the most recent quantitative test.

During the year ended December 31, 2018, the Partnership recorded the following impairments:

- A $378 million impairment was recorded related to the goodwill associated with the Partnership's Northeast operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded. These changes in assumptions reflect delays in the construction of third-party takeaway capacity in the Northeast. Additionally, the Partnership recorded asset impairments of $4 million related to our midstream operations and asset impairments $9 million related to our crude operations idle leased assets.
- Sunoco LP also recognized a $30 million impairment charge on its contractual rights primarily due to decreases in projected future revenues and cash flows from the date the intangible asset was originally recorded.
- USAC also recognized a $9 million fixed asset impairment related to certain idle compressor assets.

During the year ended December 31, 2017, the Partnership recorded the following impairments:

- a $223 million impairment was recorded related to the goodwill associated with CDM. In January 2018, the Partnership announced the contribution of CDM to USAC. Based on the Partnership's anticipated proceeds in the contribution transaction, the implied fair value of the CDM reporting unit was less than the Partnership's carrying value. As the Partnership believes that the contribution consideration also represented an appropriate estimate of fair value as of the 2017 annual impairment test date, the Partnership recorded an impairment for the difference between the carrying value and the fair value of the reporting unit. Subsequent to the impairment, a total of $253 million of goodwill remains in the CDM reporting unit, which amount is subject to further impairment based on changes in the contribution transaction prior to closing or any other factors affecting the fair value of the CDM reporting unit. Assuming the contribution transaction closes, the remaining CDM goodwill balance will be derecognized; if the transaction does not close, then the CDM goodwill balance will remain on the Partnership's consolidated balance sheet and will continue to be tested for impairment in the future.

- a $262 million impairment was recorded related to the goodwill associated with the Partnership's interstate transportation and storage reporting units, and a $229 million impairment was recorded related to the goodwill associated with the general partner of Panhandle in the all other segment. These impairments were due to a reduction in management's forecasted future cash flows from the related reporting units, which reduction reflected the impacts discussed in "Results of Operations" above, along with the impacts of re-contracting assumptions related to future periods.
- a $79 million impairment was recorded related to the goodwill associated the Partnership's refined products transportation and services reporting unit. Subsequent to the Sunoco Logistics Merger, the Partnership restructured the internal reporting of legacy Sunoco Logistics' business to be consistent with the internal reporting of legacy ETO. Subsequent to this reallocation the carrying value of certain refined products reporting units was less than the estimated fair value due to a reduction in management's forecasted future cash flows from the related reporting units, and the goodwill associated with those reporting units was fully impaired. No goodwill remained in the respective reporting units subsequent to the impairment.
- a $127 million impairment of property, plant and equipment related to Sea Robin primarily due to a reduction in expected future cash flows due to an increase during 2017 in insurance costs related to offshore assets.
- a $141 million impairment of the Partnership's equity method investment in FEP. The Partnership concluded that the carrying value of its investment in FEP was other than temporarily impaired based on an anticipated decrease in production in the Fayetteville basin and a customer re-contracting with a competitor during 2017.
- a $172 million impairment of the Partnership's equity method investment in HPC primarily due to a decrease in projected future revenues and cash flows driven be the bankruptcy of one of HPC's major customers in 2017 and an expectation that contracts expiring in the next few years will be renewed at lower tariff rates and lower volumes.
- For 2017, Sunoco LP also recognized impairments of $404 million, of which $119 million was allocated to continuing operations, as discussed further below.

During the year ended December 31, 2016, the Partnership recorded the following impairments:

- a $638 million goodwill impairment and a $133 million impairment to property, plant and equipment were recorded in the interstate transportation and storage segment primarily due to decreases in projected future revenues and cash flows driven by changes in the markets that these assets serve.
- a $32 million goodwill impairment was recorded in the midstream segment primarily due to decreases in projected future revenues and cash flows driven by declines in commodity prices.
- a $308 million impairment of the Partnership's equity method investment in MEP. The Partnership concluded that the carrying value of its investment in MEP was other than temporarily impaired based on commercial discussions with current and potential shippers on MEP during 2016, which negatively affected the outlook for long-term transportation contract rates.
- For 2016, Sunoco LP also recognized impairments of $641 million, of which $227 million was allocated to continuing operations, as discussed further below.

Except for the 2017 impairment of the goodwill associated with CDM, as discussed above, the goodwill impairments recorded by the Partnership during the years ended December 31, 2018, 2017 and 2016 represented all of the goodwill within the respective reporting units.

During 2017, Sunoco LP announced the sale of a majority of the assets in its retail and Stripes reporting units. These reporting units include the retail operations in the continental United States but excludes the retail convenience store operations in Hawaii that comprise the Aloha reporting unit. Upon the classification of assets and related liabilities as held for sale, Sunoco LP's management applied the measurement guidance in ASC 360, Property, Plant and Equipment, to calculate the fair value less cost to sell of the disposal group. In accordance with ASC 360-10-35-39, Sunoco LP's management first tested the goodwill included within the disposal group for impairment prior to measuring the disposal group's fair value less the cost to sell. In the determination of the classification of assets held for sale and the related liabilities, Sunoco LP's management allocated a portion of the goodwill balance previously included in the Sunoco LP retail and Stripes reporting units to assets held for sale based on the relative fair values of the business to be disposed of and the portion of the respective reporting unit that will be retained in accordance with ASC 350-20-40-3.

Sunoco LP recognized goodwill impairments of $387 million in 2017, of which $102 million was allocated to continuing operations, primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

Additionally, Sunoco LP performed impairment tests on their indefinite-lived intangible assets during the fourth quarter of 2017 and recognized $13 million and $4 million impairment charge on their contractual rights and liquor licenses primarily due to decreases in projected future revenues and cash flows from the date the intangible asset was originally recorded.

For the year ended December 31, 2016, Sunoco LP recognized goodwill impairments of $641 million, of which $227 million was allocated to continuing operations, primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

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 discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2018 and 2017, 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 AROs 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. We believe we may have additional AROs related to Sunoco, Inc.'s pipeline assets and storage tanks, for which it is not possible to estimate whether or when the AROs will be settled. Consequently, these AROs cannot be measured at this time. Sunoco LP has AROs related to the estimated future cost to remove underground storage tanks.

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 $106 million and $103 million and were reflected as property, plant and equipment on our consolidated balance sheet as of December 31, 2018 and 2017, respectively. In addition, other non-current assets on the Partnership's consolidated balance sheet included $26 million and $21 million of legally restricted funds for the purpose of settling AROs as of December 31, 2018 and 2017, 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. ETO has established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, ETO accrues losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. ETO'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. The Partnership's consolidated balance sheet reflected $337 million in environmental accruals as of December 31, 2018.

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. ET 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 $768 million have been included in ET's consolidated balance sheet as of December 31, 2018. The state NOL carryforward benefits of $213 million ($168 million net of federal benefit) begin to expire in 2019 with a substantial portion expiring between 2032 and 2038. The federal NOLs of $2.60 billion ($546 million in benefits) will expire in 2031 and 2037 if attributable to tax years prior to 2018. Any federal NOL generated in 2018 and future years can be carried forward indefinitely. Federal alternative minimum tax credit carryforwards of $31 million remained at December 31, 2018. We have determined that a valuation allowance totaling $124 million ($98 million net of federal income tax effects) is required for the state NOLs at December 31, 2018 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 ability of our subsidiaries to make cash distributions to us, which is dependent on their results of operations, cash flows and financial condition;
- the actual amount of cash distributions by our subsidiaries to us;
- the volumes transported on our subsidiaries' pipelines and gathering systems;
- the level of throughput in our subsidiaries' processing and treating facilities;
- the fees our subsidiaries charge and the margins they realize for their gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;

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

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

Inflation

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

(Tabular dollar amounts are in millions)

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

Commodity Price Risk

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 utilize swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

We use futures and swaps to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales. 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 tables below summarize commodity-related financial derivative instruments, fair values and the effect of an assumed hypothetical 10% change in the underlying price of the commodity as of December 31, 2018 and 2017 for ETO and Sunoco LP, including derivatives related to their respective subsidiaries. Dollar amounts are presented in millions.

	December 31, 2018			December 31, 2017		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (BBtu):						
Fixed Swaps/Futures	468	$ —	$ —	1,078	$ —	$ —
Basis Swaps IFERC/NYMEX(1)	16,845	7	1	48,510	2	1
Options – Puts	10,000	—	—	13,000	—	—
Power (Megawatt):						
Forwards	3,141,520	6	8	435,960	1	1
Futures	56,656	—	—	(25,760)	—	—
Options – Puts	18,400	—	—	(153,600)	—	1
Options – Calls	284,800	1	—	137,600	—	—
Crude (MBbls) – Futures	—	—	—	—	1	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(30,228)	(52)	13	4,650	(13)	4
Swing Swaps IFERC	54,158	12	—	87,253	(2)	1
Fixed Swaps/Futures	(1,068)	19	1	(4,390)	(1)	2
Forward Physical Contracts	(123,254)	(1)	32	(145,105)	6	41
NGL (MBbls) – Forwards/Swaps	(2,135)	67	67	(2,493)	5	16
Crude (MBbls) – Forwards/Swaps	20,888	(60)	29	9,237	(4)	9
Refined Products (MBbls) – Futures	(1,403)	(8)	6	(3,901)	(27)	4
Corn (thousand bushels)	(1,920)	—	1	1,870	—	—
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(17,445)	(4)	—	(39,770)	(2)	—
Fixed Swaps/Futures	(17,445)	(10)	6	(39,770)	14	11

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

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

Interest Rate Risk

As of December 31, 2018, we and our subsidiaries had $9.76 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $98 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding, none of which were designated as hedges for accounting purposes (dollar amounts presented in millions):

		Notional Amount Outstanding	
Term	Type[(1)]	December 31, 2018	December 31, 2017
July 2018 [(2)]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	$ —	$ 300
July 2019 [(2)]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	400	300
July 2020 [(2)]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	400
July 2021 [(2)]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	400	—
December 2018	Pay a floating rate and receive a fixed rate of 1.53%	—	1,200
March 2019	Pay a floating rate 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 30 years with a mandatory termination date the same as the effective date.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a change in the fair value of the interest rate derivatives and earnings (recognized in gains (losses) on interest rate derivatives) of approximately $259 million as of December 31, 2018. For ETO's $300 million of interest rate swaps whereby it pays a floating rate and receives a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flow of less than $1 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

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 industrial end-users, 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.

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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2018.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer LP and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 2013 *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO Framework").

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of LE GP, LLC and
Unitholders of Energy Transfer LP

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Energy Transfer LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2018, and our report dated February 22, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion
The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

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

/s/ GRANT THORNTON LLP

Dallas, Texas
February 22, 2019

Changes in Internal Controls over Financial Reporting

There has been no change in our internal controls over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

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

As of December 31, 2018, our Board of Directors was comprised of eight persons, three of whom qualify as "independent" under the NYSE's corporate governance standards. We have determined that Messrs. Brannon, Anderson and Grimm are all "independent" under the NYSE's corporate governance standards.

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

__Risk Oversight__

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

Corporate Governance

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

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

Annual Certification

In 2018, our Chief Executive Officer provided to the NYSE the annual CEO certification regarding our compliance with the NYSE's corporate governance listing standards.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the general partner is fair and reasonable to the Parent Company and our Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Parent Company to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Parent Company. Pursuant to the terms of our partnership agreement, any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Parent Company, approved by all partners of the Parent Company and not a breach by the general partner or its Board of Directors of any duties they may owe the Parent Company or the Unitholders. These duties are limited by our Partnership Agreement (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE's standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407(d)(5) of Regulation S-K. The Board determined that based on relevant experience, Audit Committee member Michael K. Grimm qualified as an audit committee financial expert during 2018. A description of the qualifications of Mr. Grimm may be found elsewhere in this Item 10 under "Directors and Executive Officers of the General Partner."

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by auditing standards, and makes recommendations to the Board of Directors relating to our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Audit Committee has received written disclosures and the letter from Grant Thornton required by applicable requirements of the Audit Committee concerning independence and has discussed with Grant Thornton that firm's independence. The Audit Committee recommended to the Board that the audited financial statements of ET be included in ET's Annual Report on Form 10-K for the year ended December 31, 2018.

The Board of Directors adopts the charter for the Audit Committee. Steven R. Anderson, Richard D. Brannon and Michael K. Grimm serve as elected members of the Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, the Board of Directors of LE GP, LLC has previously established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans, including the performance standards or other restrictions pertaining to the vesting of any such awards. Messrs. Anderson and Grimm serve as members of the Compensation Committee.

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

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

- annually review and approve goals and objectives relevant to compensation of our CEO and CFO, if applicable;
- annually evaluate the CEO and CFO's performance in light of these goals and objectives, and make recommendations to the Board of Directors with respect to the CEO and CFO's compensation levels, if applicable, based on this evaluation;
- make determinations with respect to the grant of equity-based awards to executive officers under ET's equity incentive plans;
- periodically evaluate the terms and administration of ET's long-term incentive plans to assure that they are structured and administered in a manner consistent with ET's goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO and CFO or executive officer compensation; and

- perform other duties as deemed appropriate by the Board of Directors.

Code of Business Conduct and Ethics

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

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. Our non-management directors alternate as the presiding director of such meetings.

We have established a procedure by which Unitholders or interested parties may communicate directly with the Board of Directors, any committee of the Board, any of the independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person, committee or group to the attention of Sonia Aubé at Energy Transfer LP 8111 Westchester Drive, Suite 600, Dallas, Texas, 75225. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our general partner as of February 22, 2019. Executive officers and directors are elected for indefinite terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	63	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)
Thomas E. Long	62	Chief Financial Officer (Principal Financial Officer)
Marshall S. (Mackie) McCrea, III	59	President, Chief Commercial Officer and Director
Matthew S. Ramsey	63	Chief Operating Officer and Director
Thomas P. Mason	62	Executive Vice President, General Counsel and President - LNG
John W. McReynolds	68	Special Advisor and Director
A. Troy Sturrock	48	Senior Vice President and Controller (Principal Accounting Officer)
Ray C. Davis	77	Director
Steven R. Anderson	69	Director
Richard D. Brannon	60	Director
Michael K. Grimm	64	Director

Messrs. Warren, Ramsey and McCrea also serve as directors of ETO's general partner. Mr. Ramsey serves as director of the general partner of Sunoco LP.

Set forth below is biographical information regarding the foregoing officers and directors of our general partner:

Kelcy L. Warren. Mr. Warren serves as Chairman and Chief Executive Officer of our general partner. He was appointed Co-Chairman of the Board of Directors of our general partner, effective upon the closing of our IPO, and in August 2007, he became the sole Chairman of the Board of our general partner and the Chief Executive Officer and Chairman of the Board of the general partner of ETO. Prior to that, Mr. Warren had served as Co-Chief Executive Officer and Co-Chairman of the Board of the general partner of ETO since the combination of the midstream and intrastate transportation storage operations of ETC OLP and the retail propane operations of Heritage in January 2004. Mr. Warren also served as the Chief Executive Officer of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Prior to the combination of the operations of ETO and Heritage Propane, Mr. Warren served as President of the general partner of ET Company I, Ltd. the entity that operated ETO's midstream assets before it acquired Aquila, Inc.'s midstream assets, having served in that capacity since 1996. From 1996 to 2000, he also served as a Director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 30 years of business experience in the energy industry. The members of our general partner selected Mr. Warren to serve as a director and as Chairman because he is ETO's Chief Executive Officer and has more than 30 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States, and brings a unique and valuable perspective to the Board of Directors.

Thomas E. Long. Mr. Long has served as the Chief Financial Officer of our general partner since February 2016. Mr. Long also served as the Chief Financial Officer and as a director of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Mr. Long also serves as Chief Financial Officer of ETO and was previously Executive Vice President and Chief Financial Officer of Regency GP LLC from November 2010 to April 2015. From May 2008 to November 2010, Mr. Long served as Vice President and Chief Financial Officer of Matrix Service Company. Prior to joining Matrix, he served as Vice President and Chief Financial Officer of DCP Midstream Partners, LP, a publicly traded natural gas and natural gas liquids midstream business company located in Denver, CO. In that position, he was responsible for all financial aspects of the company since its formation in December 2005. From 1998 to 2005, Mr. Long served in several executive positions with subsidiaries of Duke Energy Corp., one of the nation's largest electric power companies. Mr. Long has served as a director of Sunoco LP since May 2016, and as Chairman of the Board of USAC since April 2018.

Marshall S. (Mackie) McCrea, III. Mr. McCrea is the President and Chief Commercial Officer of our general partner, having served in that role since October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. Prior to that time, he had been the Group Chief Operating Officer and Chief Commercial Officer of the Energy Transfer family since November 2015. Mr. McCrea has served on the Board of Directors of our general partner since December 2009. Mr. McCrea was appointed as a director of the general partner of ETO in December 2009. Prior to that, he served as President and Chief Operating Officer of ETO's general partner from June 2008 to November 2015 and President – Midstream from March 2007 to June 2008. Previously he served as the Senior Vice President – Commercial Development since January 2004. In March 2005, Mr. McCrea was named President of La Grange Acquisition LP, ETO's primary operating subsidiary, after serving as Senior Vice President-Business Development and Producer Services since 1997. Mr. McCrea also served as the Chairman of the Board of Directors of the general partner of Sunoco Logistics from October 2012 to April 2017. The members of our general partner selected Mr. McCrea to serve as a director because he brings extensive project development and operational experience to the Board. He has held various positions in the natural gas business over the past 25 years and is able to assist the Board of Directors in creating and executing the Partnership's strategic plan.

Matthew S. Ramsey. Mr. Ramsey was appointed as a director of ET's general partner in July 2012 and as a director of ETO's general partner in November 2015. Mr. Ramsey has been the Chief Operating Officer or our general partner since October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P., and currently serves as President and Chief Operating Officer of ETO's general partner since November 2015. Mr. Ramsey also served as President and Chief Operating Officer and Chairman of the board of directors of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Mr. Ramsey is also a director of Sunoco LP, having served as chairman of Sunoco LP's board since April 2015, and of USAC, having served on that board since April 2018. Mr. Ramsey previously served as President of RPM Exploration, Ltd., a private oil and gas exploration partnership, and previously served as a director of RSP Permian, Inc. where he served on the audit and compensation committees. Mr. Ramsey formerly served as President of DDD Energy, Inc. until its sale in 2002. From 1996 to 2000, Mr. Ramsey served as President and Chief Executive Officer of OEC Compression Corporation, Inc., a publicly traded oil field service company, providing gas compression services to a variety of energy clients. Previously, Mr. Ramsey served as Vice President of Nuevo Energy Company, an independent energy company. Additionally, he was employed by Torch Energy Advisors, Inc., a company providing management and operations services to energy companies including Nuevo Energy, last serving as Executive Vice President. Mr. Ramsey joined Torch Energy as Vice President of Land and was named Senior Vice President of Land in 1992. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey is a graduate of Harvard Business School Advanced Management Program. Mr. Ramsey is licensed to practice law in the State of Texas. He is qualified to practice in the Western District of Texas and the United States Court of Appeals for the Fifth Circuit. Mr. Ramsey formerly served as a director of Southern Union Company. The member of our general partner recognize Mr. Ramsey's vast experience in the oil and gas space and believe that he provides valuable industry insight as a member of our Board of Directors.

Thomas P. Mason. Mr. Mason became Executive Vice President and General Counsel of the general partner of ET in December 2015, and has served as the Executive Vice President, General Counsel and President - LNG since October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. Mr. Mason also served as a director of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Mr. Mason previously served as Senior Vice President, General Counsel and Secretary of ETO's general partner from April 2012 to December 2015, as Vice President, General Counsel and Secretary from June 2008 and as General Counsel and Secretary from February 2007. Prior to joining ETO, he was a partner in the Houston office of Vinson & Elkins. Mr. Mason has specialized in securities offerings and mergers and acquisitions for more than 25 years. Mr. Mason also served on the Board of Directors of the general partner of Sunoco Logistics from October 2012 to April 2017 and has served on the Board of Directors of USAC since April 2018.

John W. McReynolds. Mr. McReynolds became Special Advisor to ET in October 2018. Prior to that time, Mr. McReynolds served as our President from March 2005 until October 2018. He has served as a Director since August 2005. He served as our Chief Financial Officer from August 2005 to June 2013, and previously served as a Director of ETO's general partner from August 2001 through May 2010. Mr. McReynolds has been in the energy industry for his entire career. Prior to joining Energy Transfer, Mr. McReynolds was in private law practice for over 20 years, specializing exclusively in energy-related finance, securities, corporations and partnerships, mergers and acquisitions, syndications, and a wide variety of energy-related litigation. His practice dealt with all forms of fossil fuels, and the transportation and handling thereof, together with the financing and structuring of all forms of business entities related thereto. The members of our general partner selected Mr. McReynolds to serve in the indicated roles with the Energy Transfer partnerships because of this extensive background and experience, as well as his many contacts and relationships in the industry.

A. Troy Sturrock. Mr. Sturrock is the Senior Vice President and Controller of our general partner having assumed that role in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. He has served as the Senior Vice President and Controller of the general partner of ETO since August 2016 and previously served as Vice President and Controller of our General Partner beginning in June 2015. Mr. Sturrock also served as a Senior Vice President of PennTex Midstream Partners, LP's general partner, from November 2016 until July 2017, and as its Controller and Principal Accounting Officer from January 2017 until July 2017. Mr. Sturrock previously served as Vice President and Controller of Regency GP LLC from February 2008, and in November 2010 was appointed as the principal accounting officer. From June 2006 to February 2008, Mr. Sturrock served as the Assistant Controller and Director of financial reporting and tax for Regency GP LLC. Mr. Sturrock is a Certified Public Accountant.

Ray C. Davis. Mr. Davis was appointed to the Board of Directors of our general partner in July 2018. From February 2018 to July 2018, Mr. Davis served on the Board of Directors of ETO. From February 2013 until February 2018, Mr. Davis was an independent investor. He has also been a principal owner, and served as co-chairman of the board of directors, of the Texas Rangers major league baseball club since August 2010. Mr. Davis previously served on the Board of Directors of the general partner of ET, effective upon the closing of ET's initial public offering in February 2006 until his resignation in February 2013. Mr. Davis also served as ETO's Co-Chief Executive Officer from the combination of the midstream and transportation operations of ETC OLP and the retail propane operations in January 2004 until his retirement from these positions in August 2007, and as Co-Chairman of the Board of Directors of our general partner from January 2004 until June 2011. Mr. Davis also held various executive positions with Energy Transfer prior to 2004. From 1996 to 2000, he served as a Director of Crosstex Energy, Inc. From 1993 to 1996, he served as Chairman of the Board of Directors and Chief Executive Officer of Cornerstone Natural Gas, Inc. The member of our general partner selected Mr. Davis to serve as a director based on his over 40 years of business experience in the energy industry and his expertise in the Partnership's asset portfolio.

Steven R. Anderson. Mr. Anderson was elected to the Board of Directors of our general partner in June 2018 and serves on the audit committee and compensation committee. Mr. Anderson began his career in the energy business in the early 1970's with Conoco in the Permian Basin area. He then spent some 25 years with ANR Pipeline and its successor, The Coastal Corporation, as a natural gas supply and midstream executive. He later was Vice President of Commercial Operations with Aquila Midstream and, upon the sale of that business to Energy Transfer in 2002, he became a part of the management team there. For the six years prior to his retirement from Energy Transfer in October 2009, he served as Vice President of Mergers and Acquisitions. Since that time, he has been involved in private investments and has served on the boards of directors of the St. John Health System and Saint Simeon's Episcopal Home in Tulsa, Oklahoma, as well as various other community and civic organizations. He also served on the Board of Directors of Sunoco Logistics Partners L.P. from October 2012 until April 2017. The members of our general partner selected Mr. Anderson to serve on the Board of Directors on the basis of his experience in the midstream industry generally and with Energy Transfer's business specifically, as well as his recent experience on the board of another publicly traded partnership.

Richard D. Brannon. Mr. Brannon was appointed to the Board of Directors of our general partner in March 2016 and has served as the Chairman of the audit committee since April 2016. Mr. Brannon is the CEO of CH4 Energy II, III, IV, V and Six, all independent companies focused on horizontal oil and gas development. Mr. Brannon served on the board of directors of WildHorse Resource Development from its IPO in December 2016 until June 2018. Mr. Brannon also formerly served on the Board of Directors and as a member of the audit committee and compensation committee of Sunoco LP, Regency, OEC Compression and Cornerstone Natural Gas Corp. He has over 35 years of experience in the energy business, having started his career in 1981 with Texas Oil & Gas. The members of our general partner selected Mr. Brannon to serve as director based on his knowledge of the energy industry and his experience as a director and audit and compensation committee member for other public companies.

Michael K. Grimm. Mr. Grimm was appointed to the Board of Directors of our general partner in October 2018, and has served on the audit committee and compensation committee since that time. Prior to that time, Mr. Grimm served as a director of ETO's general partner beginning in December 2005, and served on the audit committee and compensation committee during that time. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and served as its President and Chief Executive Officer from 1995 until 2006 when it was sold. Mr. Grimm is currently President of Rising Star Petroleum, LLC. Mr. Grimm was formerly Chairman of the Board of RSP Permian, Inc. (NYSE: RSPP) from January 2014 until June 2018 and since November 2018 has served on the Board of Directors of Anadarko Petroleum Corporation (NYSE: APC). Prior to the formation of Rising Star, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for thirteen years where he held numerous positions throughout the exploration department in Houston, New Orleans and Chicago. Mr. Grimm has been an active member of the Independent Petroleum Association of America, the American Association of Professional Landmen, Dallas Producers Club, Houston Producers Forum, Fort Worth Wildcatters and the All-American Wildcatters. He has a B.B.A. from the University of Texas at Austin. The members of our general partner selected Mr. Grimm to serve as a director because of his extensive experience in the energy industry and his service as a senior executive at several energy-related companies, in addition to his contacts in the industry gained through his involvement in energy-related organizations.

Compensation of the General Partner

Our general partner does not receive any management fee or other compensation in connection with its management of the Partnership.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the directors and executive officers of our general partner, as well as persons who own more than ten percent of the common units representing limited partnership interests in us, to file reports of ownership and changes of ownership on Forms 3, 4 and 5 with the SEC. The SEC regulations also require that copies of these Section 16(a) reports be furnished to us by such reporting persons. Based upon a review of copies of these reports, we believe all applicable Section 16(a) reports were timely filed in 2018.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner. Our General Partner is majority owned by Mr. Kelcy Warren.

We own 100% of ETP GP and its general partner, ETP LLC. We refer to ETP GP and ETP LLC together as the “ETP GP Entities.” ETP GP is the general partner of ETO.

Compensation Discussion and Analysis

Named Executive Officers

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

- Kelcy L. Warren, Chairman and Chief Executive Officer;
- Thomas E. Long, Chief Financial Officer;
- Marshall S. (Mackie) McCrea, III, President and Chief Commercial Officer;
- Matthew S. Ramsey, Chief Operating Officer;
- Thomas P. Mason, Executive Vice President, General Counsel and President — LNG; and
- John W. McReynolds, Former President (currently Special Advisor to the Partnership).

Our Philosophy for Compensation of Executives

In general, our General Partner’s philosophy for executive compensation is based on the premise that a significant portion of each executive’s compensation should be incentive-based or “at-risk” compensation and that executives’ total compensation levels should be highly competitive in the marketplace for executive talent and abilities. Our General Partner seeks a total compensation program for the named executive officers that provides for a slightly below the median market annual base compensation rate (i.e. approximately the 40^{th} percentile of market) but incentive-based compensation composed of a combination of compensation vehicles to reward both short and long-term performance that are both targeted to pay-out at approximately the top-quartile of market. Our General Partner believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of the Partnership’s financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of its named executive officers to the success of the Partnership and the achievement of the annual financial performance objectives and (ii) the annual grant of time-based restricted unit or phantom unit awards under the Partnership’s equity incentive plan(s) or the equity incentive programs of Sunoco LP, as applicable based on the allocation of the named executive officers’ award, which awards are intended to provide a longer term incentive and retention value to its key employees to focus their efforts on increasing the market price of its publicly traded units and to increase the cash distribution the Partnership and/or the other affiliated partnerships pay to their respective unitholders.

The Partnership grants restricted unit and/or phantom unit awards that vest, based generally upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year of service. The Partnership believes that these equity-based incentive arrangements are important in attracting and retaining executive officers and key employees as well as motivating these individuals to achieve stated business objectives. The equity-based compensation reflects the importance our General Partner places on aligning the interests of its named executive officers with those of unitholders.

As discussed below, our compensation committee, the ETO Compensation Committee (prior to the Energy Transfer Merger) and/or the compensation committee of the general partner of Sunoco LP, as applicable, all in consultation with our General Partner, are responsible for the compensation policies and compensation level of the named executive officers of our General Partner. In this discussion, we refer to our compensation committee as the “ET Compensation Committee.”

Sunoco LP does not participate or have any input in any decisions as to the compensation policies of Sunoco GP LLC or the compensation levels of the executive officers of its general partner. The Sunoco LP Compensation Committee is responsible for the approval of the compensation policies and the compensation levels of the executive officers of Sunoco GP LLC.

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

Distributions to Our General Partner

Our General Partner is majority-owned by Mr. Warren. We pay quarterly distributions to our General Partner in accordance with our partnership agreement with respect to its ownership of its general partner interest as specified in our partnership agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our partnership agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner's executive officers. Distributions to our General Partner are described in detail in Note 8 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers or the services they perform as employees.

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

Compensation Philosophy

Our compensation programs are structured to achieve the following:

- reward executives with an industry-competitive total compensation package of base salaries and significant incentive opportunities yielding a total compensation package approaching the top-quartile of the market;
- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based or "at-risk" compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2018, the compensation paid to our named executive officers consisted of the following components:

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

Methodology

The ET Compensation Committee considers relevant data available to it to assess our competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers, including the named executive officers. The ET Compensation Committee also considers individual performance, levels of responsibility, skills and experience.

Periodically, the ET Compensation Committee engages a third-party consultant to provide a full market competitive compensation analysis for compensation levels at peer companies in order to assist in the determination of compensation levels for our executive officers, including the named executive officers. Most recently, Longnecker & Associates ("Longnecker") evaluated the market competitiveness of total compensation levels of a number of officers of the Partnership to provide market information with respect to compensation of those executives during the year ended December 31, 2017. In particular, the review by Longnecker was designed to (i) evaluate the market competitiveness of total compensation levels for certain members of senior management, including our named executive officers; (ii) assist in the determination of appropriate compensation levels for our senior management, including the named executive officers; and (iii) confirm that our compensation programs were yielding compensation packages consistent with our overall compensation philosophy.

In conducting its review, Longnecker specifically considered the larger size of the combined ET and ETO entities from an energy industry perspective. During 2017, Longnecker assisted in the development of the final "peer group" of leading companies in the energy industry that most closely reflect the profile of ET and ETO in terms of revenues, assets and market value as well as competition for talent at the senior management level and similarly situated general industry companies with similar revenues, assets and market value. In setting such peer group, the size of ET and ETO on a combined basis was considered. As part of the evaluation conducted by Longnecker, a determination was made to focus the analysis specifically on the energy industry based on a determination that an energy industry peer group provided a more than sufficient amount of comparative data to consider and evaluate total compensation. This decision allowed Longnecker to report on specific industry related data comparing the levels of annual base salary, annual short-term cash bonus and long-term equity incentive awards at industry peer group companies with those of the named executive officers to ensure that compensation of the named executive officers is both consistent with the compensation philosophy and competitive with the compensation for executive officers of these other companies. The identified companies were:

Energy Peer Group:	
• Conoco Phillips	• Anadarko Petroleum Corporation
• Enterprise Products Partners, L.P.	• Marathon Petroleum Corporation
• Plains All American Pipeline, L.P.	• Kinder Morgan, Inc.
• Halliburton Company	• The Williams Companies, Inc.
• Valero Energy Corporation	• Phillips 66

The compensation analysis provided by Longnecker in 2017 covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term incentive awards for the senior executives of these companies. In preparing the review materials, Longnecker utilized generally accepted compensation principles as determined by WorldatWork and gathered data from the public peer companies and published salary surveys.

Following Longnecker's 2017 review, the ET Compensation Committee reviewed the information provided, including Longnecker's specific conclusions and recommended considerations for all compensation going forward. The ET Compensation Committee considered and reviewed the results of the study performed by Longnecker to determine if the results indicated that the compensation programs were yielding a competitive total compensation model prioritizing incentive-based compensation and rewarding achievement of short and long-term performance objectives and considered Longnecker's conclusions and recommendations. While Longnecker found that the Partnership is achieving its stated objectives with respect to the "at-risk" approach, they also found that certain adjustments should be implemented during 2017 to allow the Partnership to achieve its targeted percentiles on base compensation and incentive compensation (short and long-term) as described below.

In addition to the information received as part of Longnecker's 2017 review, the ET Compensation Committee also utilizes information obtained from other sources in its determination of compensation levels for our named executive officers, such as annual third party surveys, although third party survey data is not used by the ET Compensation Committee to benchmark the amount of total compensation or any specific element of compensation for the named executive officers.

While Longnecker did not provide a full study to the Partnership during 2018, Longnecker did provide (i) advice and feedback on the structure of the 2018 amendments to the Amended and Restated Energy Transfer Partners, L.L.C. Annual Bonus Plan (the "Bonus Plan"); and (ii) data and advice with respect to the Special Bonus award to Mr. Long. Additionally, Longnecker considered and provided feedback on the appropriateness, targets and composition of the 2018 equity award pool and the 2018 annual bonus awards under the Bonus Plan and benchmarking on certain non-named executive officer hires and promotions.

Base Salary. Base salary is designed to provide for a competitive fixed level of pay that attracts and retains executive officers, and compensates them for their level of responsibility and sustained individual performance (including experience, scope of responsibility and results achieved). The salaries of the named executive officers are reviewed on an annual basis. As discussed above, the base salaries of our named executive officers are targeted to yield an annual base salary slightly below the median level of market (i.e. approximately the 40th percentile of market) and are determined by the ET Compensation Committee after taking into account the recommendations of Mr. Warren.

During the 2018 merit review process, the ET Compensation Committee considered the recommendations of Mr. Warren, the existing Longnecker study (with the data aged as appropriate) and the merit increase pool set for all employees of the Partnership and/or its employing affiliates. The ET Compensation Committee approved a 3.0% increase to the base salary of Mr. McCrea to $1,076,865 from its prior level of $1,045,000; a 3.0% base salary increase to Mr. Long to $545,900 from its prior level of $530,000; a 3.0% base salary increase to Mr. Ramsey to $673,041 from its prior level of $653,438; a 3% base salary increase to Mr. Mason to $610,044 from its prior level of $592,276; and a 3.0% increase for. Mr. McReynolds to $615,967 from its prior level of $598,026. Mr. Warren has voluntarily determined that his salary will be $1.00 per year (plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits), and, as such, did not receive any base salary or adjustment in 2018.

The 3.0% increase to Messrs. McCrea, Long, Ramsey, Mason and McReynolds reflected a base salary increase consistent with the 3.0% annual merit increase pool set for all employees of ET and its affiliates for 2018.

Annual Bonus. In addition to base salary, the ET Compensation Committee makes determinations whether to make discretionary annual cash bonus awards to executives, including our named executive officers, following the end of the year under the Bonus Plan.

The Bonus Plan is a discretionary annual cash bonus plan available to all employees, including the named executive officers. The purpose of the Bonus Plan is to reward employees for contributions towards the Partnership's business goals and to aid in motivating employees. The Bonus Plan is administered by the ET Compensation Committee and the ET Compensation Committee has the authority to establish and interpret the rules and regulations relating to the Bonus Plan, to select participants, to determine and approve the size of any actual award amount, to make all determinations, including factual determinations, under the Bonus Plan, and to take all other actions necessary or appropriate for the proper administration of the Bonus Plan.

For each calendar year (the "Performance Period"), the ET Compensation Committee will evaluate and determine an overall funded cash bonus pool based on achievement of (i) an internal Adjusted EBITDA target ("Adjusted EBITDA Target"), (ii) an internal distributable cash flow target ("DCF Target") and (iii) performance of each department compared to the applicable departmental budget ("Departmental Budget Target"). The Adjusted EBITDA Target and the DCF Target are defined for purposes of the Bonus Plan using the same definitions as used in the Partnership's audited financial statements included in its annual and quarterly filings on Forms 10-K and 10-Q for the terms Adjusted EBITDA and Distributable Cash Flow. The performance criteria are weighted 60% on the achievement of the Adjusted EBITDA Target, 20% on the achievement of the DCF Target and 20% on the achievement of the Departmental Budget Target (collectively, "Budget Targets"). The total amount of cash to be allocated to the funded bonus pool will range from 0% to 120% for each of the budgeted DCF Target and Adjusted EBITDA Target and will range from 0% to 100% of the Departmental Budget Target. The maximum funding of the bonus pool is 116% of the total pool target and to achieve such funding each of the Adjusted EBITDA and the DCF Target must achieve 120% funding and the Department Budget target must achieve its 100% target. While the funded bonus pool will reflect an aggregation of performance under each target, in the event performance under the Adjusted EBITDA Target is below 80% of its target, no bonus pool will be funded. If the bonus pool is funded, a participant may earn a cash award for the Performance Period based upon the level of attainment of the Budget Targets and his or her individual performance. Awards are paid in cash as soon as practicable after the end of the Performance Period but in no event later than two and one-half months after the end of the Performance Period.

While the achievement of the Budget Targets sets a bonus pool under the Bonus Plan, actual bonus awards are discretionary. These discretionary bonuses, if awarded, are intended to reward our named executive officers for the achievement of the Budget Targets during the Performance Period in light of the contribution of each individual to our profitability and success during such year. The ET Compensation Committee also considers the recommendation of Mr. Warren in determining the specific annual cash bonus amounts for each of the named executive officers. The ET Compensation Committee does not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and it does not utilize any formulaic approach to determine annual bonuses.

For 2018, the ET Compensation Committee approved short-term annual cash bonus pool targets for Mr. McCrea of 160% of his annual base earnings and for Messrs. Long, Ramsey, Mason and McReynolds of 130% of their annual base earnings. The named executive officer bonus pool targets remained the same for the 2019 Performance Period as they were for the 2017 period.

In February 2019, the ET Compensation Committee certified 2018 performance results under the Bonus Plan, which resulted in a bonus payout of 110% of the bonus pool target, which reflected achievement of 110% of the Adjusted EBITDA Target, 120% of the DCF Target and 100% of the Department Budget Target. Based on the approved results, the ET Compensation Committee approved a cash bonus relating to the 2018 calendar year to Messrs. McCrea, Long, Ramsey, Mason and McReynolds in the amounts of $1,866,000, $800,000, $900,000, $858,700 and $800,000, respectively.

In approving the 2018 bonuses of the named executive officers, the ET Compensation Committee took into account the achievement by the Partnership of all of the targeted performance objectives for 2018 and the individual performances of each of the named executive officers. The cash bonuses awarded to each of the named executive officers for 2018 performance were materially consistent with their applicable bonus pool targets. As with base salary and equity awards, Mr. Warren does not accept or receive an annual bonus.

Equity Awards. In connection with the Energy Transfer Merger, ET assumed the obligations of ETO under the ETO equity plans and assumed such plans for purposes of employing such plans to make grants of equity-based awards relating to ET common units following the closing of the merger. The ETO equity plans assumed by ET, which have been subsequently renamed, are (i) the Second Amended and Restated Energy Transfer LP 2008 Incentive Plan (the "2008 Incentive Plan"); (ii) the Energy Transfer LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan") and the (iii) Energy Transfer LP 2015 Long-Term Incentive Plan (the "2015 Plan").

In 2017, ET adopted the Amended and Restated Energy Transfer LP Long-Term Incentive Plan (formerly the Amended and Restated Energy Transfer Equity, L.P. Long Term Incentive Plan, together with the 2008 Incentive Plan, the 2011 Incentive Plan and the 2015 Plan, the "ET Incentive Plans"). The ET Incentive Plans authorize the ET Compensation Committee, in its discretion, to grant awards, as applicable under each respective plan of restricted units, phantom units, unit options, unit appreciation rights and other awards related to ET common units upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by the ET Incentive Plans.

For 2018, the annual long-term incentive targets set by the ET Compensation Committee for the named executive officers were 900% of annual base salary for Mr. McCrea and 500% of annual base salary for Messrs. Long, Ramsey and Mason. Due to his significant holdings of ET units, Mr. McReynolds does not receive annual equity awards. The 500% target for Mr. Ramsey is a decrease from his previous target of 600% and represents a desire on the part of the Chairman to align the senior officers that report to him, other than Mr. McCrea, with a consistent long-term incentive target. The targets of the other named executive officers were consistent with the prior year's targets.

In December 2018, the ET Compensation Committee in consultation with ET's Chairman determined to issue long-term incentive awards in the form of restricted units under the ET Incentive Plans to the ET named executive officers, other than Mr. McReynolds, who as noted above does not currently receive long-term incentive awards. In December of 2018, the ET Compensation Committee approved grants of phantom unit awards to Messrs. McCrea, Long, Ramsey and Mason of 605,470 units, 136,475 units, 168,260 units and 190,640 units, respectively. As with base salary and annual bonus, Mr. Warren does not accept or receive annual long term incentive awards.

As more fully described below in the section titled *Affiliate and Subsidiary Equity Awards*, for 2018, in discussions between the General Partner, the ET Compensation Committees and the compensation committee of the general partner of Sunoco LP, it was determined that for 2018 the value of Messrs. Long and Ramsey's awards would be comprised of restricted unit awards under the ET Incentive Plans and the Sunoco LP 2018 Long-Term Incentive Plan (the "2018 Sunoco LP Plan") in consideration of their roles and responsibilities for Sunoco LP and their status, as members of the Boards of Directors of the general partner of Sunoco LP. Messrs. Long and Ramsey's total 2018 long-term awards were allocated 80% to the ET Incentive Plans and 20% to the 2018 Sunoco LP Plan. The awards of Messrs. McCrea and Mason for 2018 were allocated entirely to the ET Incentive Plans. In the case of Mr. Mason this represented a change from prior year allocations of awards under the long-term incentive plans of affiliates as his time for 2018 was almost fully dedicated to ET and his role at Sunoco LP was reduced as a result of his additional ET responsibilities. It is expected that future long-term incentive awards to Messrs. Long and Ramsey of ET will recognize an aggregation of restricted units under the ET Incentive Plans and the 2018 Sunoco LP Plan, as applicable.

The restricted unit awards granted in 2018 provide for incremental vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year. Vesting of the awards are generally subject to continued employment through each specified vesting date. The restricted unit awards entitle the recipients to receive, with respect to each ET unit subject to such award that has not either vested or been forfeited, a DER cash payment promptly following each such distribution by ET to its unitholders. In approving the grant of such restricted unit awards, including to the named executive officers, the ET Compensation Committee considered several factors, including the long-term objective of retaining such individuals as key drivers of ET's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity awards subject to vesting. Vesting of the 2018 awards would accelerate in the event of the death or disability of the recipient, including the named executive officers, or in the event of a change in control of ET as that term is defined under the ET Incentive Plans.

As discussed below under "Potential Payments Upon a Termination or Change of Control," all outstanding equity would automatically accelerate upon a change in control event, which means vesting automatically accelerates upon a change of control irrespective of whether the officer is terminated. In addition, the 2014 awards to Mr. McCrea included a provision in the applicable award agreement for acceleration of unvested restricted unit/restricted phantom unit awards upon a termination of employment by the general partner of the applicable partnership issuing the award without "cause". For purposes of the awards the term "cause" shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the partnership or any of its or their affiliates by, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the partnership or any of its or their affiliates. In addition, the award agreements for the restricted units awarded in 2018, as well as other awards outstanding held by Partnership employees, including the named executive officers, also include certain acceleration provisions upon retirement with the ability to accelerate 40% of outstanding unvested awards under the ET Incentive Plans at age 65 and 50% at age 68. These acceleration provisions require that the participant have not less than five (5) years of employment service to the Partnership or an affiliate and require a six (6) month delay in the vesting after retirement pursuant to the requirements of Section 409(A) of the Code.

We believe that permitting the accelerated vesting of equity awards upon a change in control creates an important retention tool for us by enabling employees to realize value from these awards in the event that we undergo a change in control transaction. In addition, we believe permitting acceleration of vesting upon a change in control and the acceleration of vesting awards upon a termination without "cause" in the case of the 2014 awards to Mr. McCrea creates a sense of stability in the course of transactions that could create uncertainty regarding their future employment and encourage these officers to remain focused on their job responsibilities.

Affiliate and Subsidiary Equity Awards. In addition to their roles as officers of for ET and ETO during 2018, Messrs. Long and Ramsey have certain responsibilities for Sunoco LP, including as members of the Board of Directors of the general partner of Sunoco LP.

The Sunoco LP Compensation Committee in December 2018 approved grants of restricted unit awards to Messrs. Long and Ramsey of 19,325 and 23,825 restricted units, respectively, under the 2018 Sunoco LP Plan. The terms and conditions of the restricted unit to Messrs. Long and Ramsey under the 2018 Sunoco LP Plan, as applicable, were the same and provided for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, subject generally to continued employment through each specified vesting date. All of the awards would be accelerated in the event of their death, disability, upon a change in control or retirement at ages 65 or 68.

Special Bonus Award. On October 19, 2018, the ET Compensation Committee approved a special one-time bonus award (the "Special Award") to Mr. Long in recognition of Mr. Long's contributions to several key strategic initiatives, including the successful Energy Transfer Merger. The Special Award was composed of $1,000,000 cash paid in one ump-sum in October 2018 and 115,200 restricted units under the 2008 Incentive Plan. The restricted units awarded to Mr. Long under the 2008 Incentive Plan carry the right to receive DER cash payments and are subject to vesting as follows: 60% of the aggregate number of ET Restricted Units on December 5, 2021, and the remaining 40% on December 5, 2023, based on continued employment with the Partnership on each such date. In the event that Mr. Long is terminated without "cause," dies or becomes disabled or there is a change in control of ET as that term is defined under the 2008 Incentive Plan, vesting of the restricted units would automatically accelerate.

For purposes of the Special Award to Mr. Long, "cause" shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the Partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the Partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the Partnership or any of its or their affiliates by, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the Partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the Partnership or any of its or their affiliates.

Unit Ownership Guidelines. The Board of Directors of our General Partner has adopted the Executive Unit Ownership Guidelines (the "Guidelines"), which set forth minimum ownership guidelines applicable to certain executives of ET with respect to ET and Sunoco LP common units representing limited partnership interests, as applicable. The applicable Guidelines are denominated as a multiple of base salary, and the amount of common units required to be owned increases with the level of responsibility. Under these Guidelines, the President and Chief Commercial Officer and the Chief Operating Officer are expected to own common units having a minimum value of five times his base salary, while each of the remaining named executive officers (other than the CEO) are expected to own common units having a minimum value of four times their respective base salary. In addition to the named executive officers, these Guidelines also apply to other covered executives, which executives are expected to own either directly or indirectly in accordance with the terms of the Guidelines, common units having minimum values ranging from two to four times their respective base salary.

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

Covered executives are generally required to achieve their ownership level within five years of becoming subject to the Guidelines; however, certain covered executives, based on their tenure as an executive, are required to achieve compliance within two years of the December 2013 effective date of the Guidelines. Thus, compliance with the Guidelines was required for Messrs. McCrea and Mason beginning in December 2015, and they were compliant. Compliance for Mr. Long was required in December 2018, and he was compliant. Compliance for Mr. Ramsey will be required in December 2020.

Covered executives may satisfy the Guidelines through direct ownership of ET and/or Sunoco LP common units or indirect ownership by certain immediate family members. Direct or indirect ownership of ET and/or Sunoco LP common units shall count on a one-to-one ratio for purposes of satisfying minimum ownership requirements; however, unvested unit awards may not be used to satisfy the minimum ownership requirements.

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

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

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

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

Termination Benefits. Our named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner; however, the award agreement to the named executive officers under the ET Incentive Plans, the 2018 Sunoco LP Plan and the Sunoco LP 2012 Long-Term Incentive Plan (the "2012 Sunoco LP Plan") provide for immediate vesting of all unvested restricted unit awards in the event of a (i) change of control, as defined in the plan; (ii) death or (iii) disability, as defined in the applicable plan. Please refer to "Compensation Tables - Potential Payments Upon a Termination or Change of Control" for additional information.

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

Energy Transfer LP Non-Qualified Deferred Compensation Plan (the "ET NQDC Plan") is a deferred compensation plan, which permits eligible highly compensated employees to defer a portion of their salary, bonus, and/or quarterly non-vested phantom unit distribution equivalent income until retirement, termination of employment or other designated distribution event. Each year under the ET NQDC Plan, eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested phantom unit distribution income, and/or 50% of their discretionary performance bonus compensation during the following year. Pursuant to the ET NQDC Plan, ET may make annual discretionary matching contributions to participants' accounts; however, ET has not made any discretionary contributions to participants' accounts and currently has no plans to make any discretionary contributions to participants' accounts. All amounts credited under the ET NQDC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings or losses based on hypothetical investment fund choices made by the participants among available funds.

Participants may elect to have their account balances distributed in one lump sum payment or in annual installments over a period of three or five years upon retirement, and in a lump sum upon other termination events. Participants may also elect to take lump-sum in-service withdrawals five years or longer in the future, and such scheduled in-service withdrawals may be further deferred prior to the withdrawal date. Upon a change in control (as defined in the ET NQDC Plan) of ET, all ET NQDC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the ET NQDC Plan's normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement. None of our named executive officers currently participate in this plan.

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

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

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

Accounting for Non-Cash Compensation

For non-cash compensation arrangements we record compensation expense over the vesting period of the awards, as discussed further in Note 9 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Mr. Michael K. Grimm and Mr. Steven R. Anderson are the only members of the Compensation Committee. During 2018, no member of the Compensation Committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company's board of directors. Mr. Grimm is not a former employee of ours or any of our subsidiaries. Mr. Anderson was previously an employee of the Partnership until his retirement in October 2009, as discussed in his biographical information included in "Item 10. Directors, Executive Officers and Corporate Governance."

Report of Compensation Committee

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

The Compensation Committee of the
Board of Directors of LE GP, LLC,
general partner of Energy Transfer LP

Michael K. Grimm
Steven R. Anderson

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

Compensation Tables

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus[1] ($)	Equity Awards [2] ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation[3] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation[4] ($)	Total ($)
Kelcy L. Warren [5]	2018	$ 6,138	$ —	$ —	$ —	$ —	$ —	$ —	$ 6,138
Chief Executive Officer	2017	5,926	—	—	—	—	—	—	5,926
	2016	5,920	—	—	—	—	—	58	5,978
Thomas E. Long	2018	537,338	1,000,000	4,251,335	—	800,000	—	21,294	6,609,967
Chief Financial Officer	2017	480,846	—	2,519,954	—	625,100	—	18,320	3,644,220
	2016	454,154	—	2,007,697	—	560,865	—	14,679	3,037,395
Marshall S. (Mackie) McCrea, III	2018	1,059,976	—	7,834,782	—	1,866,000	—	19,362	10,780,120
President and Chief Commercial Officer	2017	1,027,846	—	9,033,341	—	1,644,554	—	16,834	11,722,575
	2016	1,009,231	—	8,059,413	—	1,533,990	—	14,818	10,617,452
Matthew S. Ramsey	2018	662,486	—	2,818,415	—	900,000	—	19,294	4,400,195
Chief Operating Officer	2017	642,404	—	3,763,893	—	835,125	—	18,618	5,260,040
	2016	630,769	—	3,433,894	—	838,901	—	87,375	4,990,939
Thomas P. Mason	2018	600,477	—	2,466,882	—	858,700	—	19,294	3,945,353
Executive Vice President, General Counsel and President – LNG	2017	582,275	—	2,816,048	—	756,958	—	18,618	4,173,899
	2016	571,729	—	2,524,064	—	706,067	—	14,818	3,816,678
John W. McReynolds	2018	606,306	—	—	—	800,000	—	15,967	1,422,273
Former President	2017	587,928	—	—	—	764,306	—	15,179	1,367,413
	2016	577,280	—	—	—	712,922	—	10,768	1,300,970

(1) For Mr. Long, the amount shown includes the cash portion of his Special Award.

(2) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718. For Messrs. Long and Ramsey amounts include equity awards of our subsidiaries and/or affiliates, as reflected in the "Grants of Plan-Based Awards Table." See Note 9 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" for additional assumptions underlying the value of the equity awards.

(3) ET maintains the Bonus Plan which provides for discretionary basis. Award of discretionary bonuses are tied to achievement of targeted performance objectives and described in the Compensation Discussion and Analysis. The discretionary cash bonus

amounts earned by the named executive officers for 2018 reflect cash bonuses approved by the ET Compensation Committee in February 2019 that are expected to be paid on or before March 15, 2019.

(4) The amounts reflected for 2018 in this column include (i) matching contributions to the ET 401(k) Plan made on behalf of the named executive officers of $13,750 each for Messrs. Long, McCrea, Ramsey and Mason and $9,300 for Mr. McReynolds, (ii) health savings account contributions made on behalf of the named executive officers of $2,000 each for Messrs. Long and McCrea, and (iii) the dollar value of life insurance premiums paid for the benefit of the named executive officers. The amounts reflected for all periods exclude distribution payments in connection with distribution equivalent rights on unvested unit awards, because the dollar value of such distributions are factored into the grant date fair value reported in the "Equity Awards" column of the Summary Compensation Table at the time that the unit awards and distribution equivalent rights were originally granted. For 2018, distribution payments in connection with distribution equivalent rights totaled $594,423 for Mr. Long, $2,183,255 for Mr. McCrea, $816,297 for Mr. Ramsey, and $759,825 for Mr. Mason.

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

Grants of Plan-Based Awards Table

Name	Grant Date	All Other Unit Awards: Number of Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($ / Unit)	Grant Date Fair Value of Unit Awards [(1)]
ET Unit Awards:					
Kelcy L. Warren	N/A	—	—	$ —	$ —
Thomas E. Long	12/18/2018	136,475	—	—	1,765,987
	10/19/2018	115,200 [(2)]			1,965,312
Marshal S. (Mackie) McCrea, III	12/18/2018	605,470	—	—	7,834,782
Matthew S. Ramsey	12/18/2018	168,260	—	—	2,177,284
Thomas P. Mason	12/18/2018	190,640	—	—	2,466,882
John W. McReynolds	N/A	—	—	—	—
Sunoco LP Unit Awards:					
Thomas E. Long	12/19/2018	19,325	—	—	520,036
Matthew S. Ramsey	12/19/2018	23,825	—	—	641,131

(1) We have computed the grant date fair value of unit awards in accordance with FASB ASC Topic 718, as further described above and in Note 9 to our consolidated financial statements.

(2) Represents restricted units subject to Mr. Long's Special Award.

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

A description of material factors necessary to understand the information disclosed in the tables above with respect to salaries, bonuses, equity awards, and 401(k) plan contributions can be found in the Compensation Discussion and Analysis that precedes these tables.

Outstanding Equity Awards at 2018 Fiscal Year-End Table

		Unit Awards [1]	
Name	Grant Date[1]	Number of Units That Have Not Vested[2] (#)	Market or Payout Value of Units That Have Not Vested [3] ($)
ET Unit Awards:			
Kelcy L. Warren	N/A	—	$ —
Thomas E. Long	12/18/2018	136,475	1,802,835
	10/19/2018	115,200	1,521,792
	12/20/2017	121,074	1,599,388
	12/29/2016	75,588	998,517
	12/9/2015	14,227	187,941
	12/4/2015	5,739	75,816
	12/16/2014	10,486	138,520
Marshal S. (Mackie) McCrea, III	12/18/2018	605,740	8,001,825
	12/20/2017	537,379	7,098,777
	12/29/2016	430,575	5,687,889
	12/9/2015	94,855	1,253,032
	12/4/2015	47,816	631,650
	12/16/2014	48,115	635,602
	12/5/2014	21,062	278,231
Matthew S. Ramsey	12/18/2018	168,260	2,222,715
	12/20/2017	223,908	2,957,825
	12/29/2016	183,601	2,425,369
	12/9/2015	59,282	783,119
Thomas P. Mason	12/18/2018	190,640	2,518,354
	12/20/2017	135,300	1,787,313
	12/29/2016	101,613	1,342,306
	12/9/2015	22,391	295,785
	12/4/2015	11,287	149,101
	12/16/2014	16,592	219,181
	12/5/2014	7,740	102,248
John W. McReynolds	N/A	—	—
Sunoco LP Unit Awards:			
Thomas E. Long	12/19/2018	19,325	$ 525,447
	12/21/2017	17,097	464,867
	12/29/2016	22,210	603,890
	12/16/2015	5,650	153,624
Matthew S. Ramsey	12/19/2018	23,825	647,802
	1/2/2015	814	22,133
	11/10/2014	299	8,130
Thomas P. Mason	12/21/2017	19,106	519,492
	12/29/2016	7,410	201,483
	12/16/2015	23,300	633,527

(1) Certain of these outstanding awards represent Energy Transfer Partners, L.P. awards that converted into ET awards upon the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. in October 2018. Furthermore, some of those converted awards had previously been converted in connection with the merger of Energy Transfer Partners, L.P. and Sunoco Logistics in April 2017.

(2) ET unit awards outstanding vest at a rate of 60% in December 2020 and 40% in December 2022 for awards granted in December 2017. Such awards may be settled at the election of the ET Compensation Committee in (i) common units of ET (subject to the approval of the ET Incentive Plans prior to the first vesting date by a majority of ET's unitholders pursuant to the rules of the New York Stock Exchange); (ii) cash equal to the Fair Market Value (as such term is defined in the ET Incentive Plans)

of the ET common units that would otherwise be delivered pursuant to the terms of each named executive officers grant agreement; or (iii) other securities or property in an amount equal to the Fair Market Value of ET common units that would otherwise be delivered pursuant to the terms of the grant agreement, or a combination thereof as determined by the ET Compensation Committee in its discretion.

Other unit awards outstanding vest as follows:

- at a rate of 60% in December 2021 and 40% in December 2023 for awards granted in October and December 2018;
- at a rate of 60% in December 2020 and 40% in December 2022 for awards granted in December 2017;
- at a rate of 60% in December 2019 and 40% in December 2021 for awards granted in December 2016;
- 100% in December 2020 for the remaining outstanding portion of awards granted in December 2015; and
- 100% in December 2019 for the remaining outstanding portion of all other awards.

(3) Market value was computed as the number of unvested awards as of December 31, 2018 multiplied by the closing price of respective common units of ET and Sunoco LP.

Option Exercises and Units Vested Table

	Unit Awards	
Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($) (1)
ET Unit Awards:		
Kelcy L. Warren	—	$ —
Thomas E. Long	38,291	556,981
Marshall S. (Mackie) McCrea, III	295,241	4,294,546
Matthew S. Ramsey	88,923	1,293,474
Thomas P. Mason	81,949	1,192,030
John W. McReynolds	—	—
Sunoco LP Unit Awards:		
Thomas E. Long	8,475	235,859
Matthew S. Ramsey	1,221	38,895
Thomas P. Mason	11,113	309,275

(1) Amounts presented represent the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the applicable closing market price of applicable common units upon the vesting date.

We have not issued option awards.

Potential Payments Upon a Termination or Change of Control

Equity Awards. As discussed in our Compensation Discussion and Analysis above, any unvested equity awards granted pursuant the ET Incentive Plans will automatically become vested upon a change of control, which is generally defined as the occurrence of one or more of the following events: (i) any person or group becomes the beneficial owner of 50% or more of the voting power or voting securities of ET or its general partner; (ii) LE GP, LLC or an affiliate of LE GP, LLC ceases to be the general partner of ET; or (iii) the sale or other disposition, including by liquidation or dissolution, of all or substantially all of the assets of ET in one or more transactions to anyone other than an affiliate of ET.

In addition, as explained in *Equity Awards* section of our Compensation Discussion and Analysis above, the restricted unit awards and phantom unit awards under the ET Incentive Plans, the Sunoco LP Plan and the 2012 Sunoco LP Plan generally require the continued employment of the recipient during the vesting period, provided however, the unvested awards will be accelerated in the event of the death or disability of the award recipient prior to the applicable vesting period being satisfied. All awards outstanding to the named executive officers under the ET Incentive Plans, the 2018 Sunoco LP Plan or the 2012 Sunoco LP Plan would be accelerated in the event of a change in control of the Partnership.

The 2014 awards to Mr. McCrea and the 2018 Special Award to Mr. Long included a provision in the applicable award agreement for acceleration of unvested restricted unit/restricted phantom unit awards upon a termination of employment by the general partner of the applicable partnership issuing the award without "cause." For purposes of the awards the term "cause" shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the partnership or any of its or their affiliates, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the partnership or any of its or their affiliates.

In addition, the ET Compensation Committee and the compensation committee of the general partner of Sunoco LP, have approved a retirement provision, which provides that employees, including the named executive officers with at least ten years of service with the general partner, who leave the respective general partner voluntarily due to retirement (i) after age 65 but prior to age 68 are eligible for accelerated vesting of 40% of his or her award; or (ii) after 68 are eligible for accelerated vesting of 50% his or her award. The acceleration of the awards is subject to the applicable provisions of IRC Section 409(A).

In February 2016, Mr. Mason received a one-time special incentive retention bonus in the amount of $6,300,000 (the "Special Bonus"). The Special Bonus was in recognition of, among other things, (i) Mr. Mason's appointment as the Executive Vice President and General Counsel of the General Partner; (ii) his 2015 calendar year performance; and (iii) his contributions to the family of partnerships on several key initiatives, including (a) the drop-down transactions by and between ETO and Sunoco LP, (b) the proposed merger transaction between the ET and The Williams Companies, Inc., (c) the liquefied natural gas (LNG) export project of ET, and (d) the simplification of the overall Energy Transfer family structure. The approval of the Special Bonus was conditioned upon entry by Mr. Mason into a Retention Agreement (the "Retention Agreement") which provides (i) if, prior to the third (3rd) anniversary of the effective date of the Retention Agreement, Mr. Mason's employment terminates (other than as a result of (x) a termination without cause or by Mr. Mason for Good Reason; (y) his death; or (z) his permanent disability), he will be obligated to remit and repay one-hundred percent (100%) of the Special Bonus to ET; (ii) if, after the third (3rd) anniversary but prior to the fourth (4th) anniversary of the effective date of the Retention Agreement, Mr. Mason's employment terminates (other than as a result of (x) a termination without cause by ET or by Mr. Mason for Good Reason; (y) his death; or (z) his permanent disability), he will be obligated to remit and repay seventy-five percent (75%) of the Special Bonus; and (iii) if, after the fourth (4th) anniversary but prior to the fifth (5th) anniversary of the effective date of the Retention Agreement, Mr. Mason's employment terminates (other than as a result of (x) a termination without cause by ET or by Mr. Mason for Good Reason; (y) his death; or (z) his permanent disability), he will be obligated to remit and repay fifty percent (50%) of the Special Bonus. Mr. Mason entered into the Retention Agreement on February 24, 2016.

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

CEO Pay Ratio

In accordance with Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, set forth below is information about the relationship of the annual total compensation of Mr. McReynolds, who served as the Principal Executive Officer of ET prior to the Energy Transfer Merger, and the annual total compensation of our employees. The Partnership has not incurred any significant changes in the composition of its employee population, compensation programs or employee benefits and as such will continue to rely on its determination of the "median employee" and the median of the annual total compensation of the employees supporting ET, as permitted, on its 2017 CEO Pay Ratio disclosure. The determination to include only Mr. McReynolds was based on the fact that he served as ET's Principal Executive Officer for 75% of the year and Mr. Warren, who is now ET's Chairman and Chief Executive Officer, does not accept or receive compensation other than an amount sufficient to cover his allocated payroll deductions for health and welfare benefits.

For the 2018 calendar year:

The annual total compensation of Mr. McReynolds, as reported in the Summary Compensation Tables of this Item 11was $5,926; and

For 2018, the median total compensation of the employees supporting ETO (other than Mr. McReynolds) was $115,908, which amount was updated from 2017 for the designated "median employee."

Based on this information, for 2017 the ratio of the annual total compensation of Mr. McReynolds to the median of the annual total compensation of the 8,494 employees supporting ETO as of December 31, 2017 was approximately 12 to 1.

To identify the median of the annual total compensation of the employees supporting ETO, the following steps were taken:

1. It was determined that, as of December 31, 2017, the applicable employee populations consisted of 8,494 with all of the identified individuals being employed in the United States. This population consisted of all of our full-time and part-time employees. We did not engage any independent contractors in 2017 or 2018 that are required to be included in our employee population for the CEO pay ratio evaluation.
2. To identify the "median employee" from our employee population, we compared the total earnings of our employees as reflected in our payroll records as reported on Form W-2 for 2017 and, for 2018, updated the compensation of the "median employee" as reflected in our payroll records as reported on Form W-2 for 2018.
3. We identified our median employee using W-2 reporting and applied this compensation measure consistently to all of our employees required to be included in the calculation. We did not make any cost of living adjustments in identifying the "median employee".
4. Once we identified our median employee, we combined all elements of the employee's compensation for 2017 resulting in an annual compensation of $115,908. The difference between such employee's total earnings and the employee's total compensation represents the estimated value of the employee's health care benefits (estimated for the employee and such employee's eligible dependents at $10,800) and the employee's 401(k) matching contribution and profit sharing contribution (estimated at $5,846 per employee, includes $3,633 per employee on average matching contribution and $2,213 per employee on average profit sharing contribution (employees earning over $175,000 in base are ineligible for profit sharing)).
5. With respect to Mr. McReynolds, we used the amount reported in the "Total" column of our 2017 Summary Compensation Table under this Item 11.

Director Compensation

Directors of our General Partner, who are employees of the ETP GP or any of their subsidiaries, are not eligible for director compensation. In 2018, the compensation arrangements for outside directors included a $100,000 annual retainer for services on the board. If a director served on the ET Audit Committee, such director would receive an annual retainer ($15,000 or $25,000 in the case of the chairman). If a director served on the ET Compensation Committee, such director would receive an annual cash retainer ($7,500 or $15,000 in the case of the chairman). The fees for membership on the Conflicts Committee are determined on a per instance basis for each committee assignment.

The outside directors of our General Partner are also entitled to an annual award under the ET Incentive Plans equal to an aggregate of $100,000 divided by the closing price of ET common units on the date of grant. These ET common units will vest 60% after the third year and the remaining 40% after the fifth year after the grant date. The compensation expense recorded is based on the grant-date market value of the ET common units and is recognized over the vesting period. Distributions are paid during the vesting period.

The compensation paid to the non-employee directors of our General Partner in 2018 is reflected in the following table:

Name	Fees Paid in Cash[1] ($)	Unit Awards[2] ($)	All Other Compensation ($)	Total ($)
Steven R. Anderson [3]				
As ET director	$ 91,760	$ 44,200	$ —	$ 135,960
Richard D. Brannon				
As ET director	194,225	100,000	—	294,225
Ray C. Davis				
As ET director	25,000	42,700	—	67,700
As ETO director	49,750	—	—	49,750
Michael K. Grimm [3]				
As ET director	—	—	—	—
As ETO director	205,425	100,068	—	305,493
K. Rick Turner [4]				
As ET director	99,701	100,000	—	199,701
As Sunoco LP Director	46,614	100,006	—	146,620
William P. Williams [4]				
As ET director	128,650	100,000	—	228,650

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

(2) Unit award amounts reflect the aggregate grant date fair value of awards granted based on the market price of ET common units, ETO common units (prior to the Merger) or Sunoco LP Common Units, accordingly, as of the grant date.

(3) Messrs. Anderson and Grimm were appointed to the Board of Directors of LE GP on June 4, 2018 and October 19, 2018, respectively.

(4) Messrs. Turner and Williams resigned from the Board of Directors of LE GP on June 1, 2018 and October 19, 2018, respectively.

As of December 31, 2018, Mr. Anderson had 2,500 unvested ET restricted units outstanding, Mr. Brannon had 13,353 unvested ET restricted units outstanding, Mr. Davis had 2,500 unvested ET restricted units outstanding and Mr. Grimm had 20,262 unvested ET restricted units outstanding.

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

Equity Compensation Plan Information

The following table sets forth in tabular format, a summary of our equity plan information as of December 31, 2018:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	—	$ —	—
Equity compensation plans not approved by security holders:	22,429,859	—	15,061,559
Total	22,429,859	$ —	15,061,559

Energy Transfer LP Units

The following table sets forth certain information as of February 15, 2019, regarding the beneficial ownership of our voting securities by (i) certain beneficial owners of more than 5% of our Common Units, (ii) each director and named executive officer of our General Partner and (iii) all current directors and executive officers of our General Partner as a group. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

Name and Address of Beneficial Owner (1)	Beneficially Owned (2)	Percent of Class
Kelcy L. Warren (3)	241,479,586	9.2%
Ray C. Davis (4)	87,891,646	3.4%
John W. McReynolds (5)	27,270,400	1.0%
Thomas E. Long	141,983	*
Marshall S. (Mackie) McCrea, III	1,922,870	*
Matthew S. Ramsey	148,051	*
Thomas P. Mason	607,850	*
Richard D. Brannon	188,932	*
Steven R. Anderson (6)	1,544,588	*
Michael K. Grimm (7)	96,313	*
All Directors and Executive Officers as a group (11 persons)	361,327,518	13.8%

* Less than 1%

(1) The address for Mr. Davis is 5950 Sherry Lane, Dallas, Texas 75225. The address for all other listed beneficial owners is 8111 Westchester Drive, Suite 600, Dallas, Texas 75225.

(2) Beneficial ownership for the purposes of this table is defined by Rule 13d-3 under the Exchange Act of 1934. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof or to dispose or direct the disposition thereof or has the right to acquire either of those powers within sixty days. The nature of beneficial ownership for all listed persons is direct with sole investment and disposition power unless otherwise noted. The beneficial ownership of each listed person is based on 2,619,391,387 Common Units outstanding in the aggregate as of February 15, 2019.

(3) Includes 98,093,962 Common Units held by Kelcy Warren Partners, L.P. and 10,244,429 Common Units held by Kelcy Warren Partners II, L.P., the general partners of which are owned by Mr. Warren. Also includes 91,585,486 Common Units held by Seven Bridges Holdings, LLC, of which Mr. Warren is a member. Also includes 328,383 Common Units attributable to the interest of Mr. Warren in ET Company Ltd and Three Dawaco, Inc., over which Mr. Warren exercises shared voting and dispositive power with Ray Davis. Also includes 601,076 Common Units held by LE GP, LLC. Mr. Warren may be deemed to own Common Units held by LE GP, LLC due to his ownership of 81.2% of its member interests. The voting and disposition of these Common Units is directly controlled by the board of directors of LE GP, LLC. Mr. Warren disclaims beneficial ownership of Common Units owned by LE GP, LLC other than to the extent of his interest in such entity. Also includes 104,166 Common Units held by Mr. Warren's spouse.

(4) Includes 51,701 Common Units held by Avatar Holdings LLC, 1,941,721 Common Units held by Avatar BW, Ltd., 28,203,003 Common Units held by Avatar ETC Stock Holdings LLC, 3,557,757 Common Units held by Avatar Investments LP, 121,117 Common Units held by Avatar Stock Holdings, LP and 1,112,069 Common Units held by RCD Stock Holdings, LLC, all of which entities are owned or controlled by Mr. Davis. Also includes 15,987,283 Common Units held by a remainder trust for Mr. Davis' spouse and 9,536,054 Common Units held by two trusts for the benefit of Mr. Davis' grandchildren, for which Mr. Davis serves as trustee. Mr. Davis shares voting and dispositive power with his wife with respect to Common Units held directly. Also includes 328,383 Common Units attributable to ET Company Ltd. Mr. Davis is a former executive officer and director of ETO and is currently a director of the general partner of ET, LE GP, LLC.

(5) Includes 17,445,608 Common Units held by McReynolds Energy Partners L.P. and 12,142,593 Common Units held by McReynolds Equity Partners L.P., the general partners of which are owned by Mr. McReynolds. Mr. McReynolds disclaims beneficial ownership of Common Units owned by such limited partnerships other than to the extent of his interest in such entities.

(6) Includes 1,544,558 held by Steven R. Anderson Revocable Trust, for which Mr. Anderson serves as trustee.

(7) Includes 5,888 Units held by two trusts for the benefit of Mr. Grimm's children, for which Mr. Grimm serves as trustee.

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

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

As of December 31, 2018, our interests in ETO consisted of 100% of the general partner interests and 1,313,568,560 ETO common units.

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETO, Sunoco LP and USAC, all of which are limited partnerships engaged in diversified energy-related services, and cash flows from the operations of Lake Charles LNG.

Mr. McCrea and Mr. Ramsey, current directors of LE GP, LLC, our general partner, are also directors and executive officers of ETO's general partner. In addition, Mr. Warren, our Chief Executive Officer and Chairman of our Board of Directors, is also the Chairman and Chief Executive Officer of ETO's general partner.

For a discussion of director independence, see Item 10. "Directors, Executive Officers and Corporate Governance."

As a policy matter, our Conflicts Committee generally reviews any proposed related party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The Partnership's board of directors makes the determinations as to whether there exists a related party transaction in the normal course of reviewing transactions for approval as the Partnership's board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors' approval is sought by the Partnership's management. In addition, the Partnership's board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership's board makes those determinations in light of its contractually-limited fiduciary duties to the Unitholders. The partnership agreement of ET provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to ET, approved by all the partners of ET and not a breach by the General Partner or its Board of Directors of any duties they may owe ET or the Unitholders (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

The Parent Company has agreements with subsidiaries to provide or receive various general and administrative services. The Parent Company pays ETO to provide services on its behalf and the behalf of other subsidiaries of the Parent Company. The Parent Company receives management fees from certain of its subsidiaries, which include the reimbursement of various general and administrative services for expenses incurred by ETO on behalf of those subsidiaries. All such amounts have been eliminated in our consolidated financial statements.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

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

	Years Ended December 31,	
	2018	2017
Audit fees (1)	$ 11.6	$ 11.5
Audit-related fees (2)	0.5	—
Tax fees (3)	0.1	—
Total	$ 12.2	$ 11.5

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

(1) Includes fees in 2018 for financial statement audits of subsidiary entities in connection with contribution and sale transactions.

(2) Includes fees in 2018 related to state and local tax consultation.

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

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee. All fees paid or expected to be paid to Grant Thornton LLP for fiscal years 2018 and 2017 were pre-approved by the Audit Committee in accordance with this policy.

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

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

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this Report:	Page
(1) Financial Statements – see Index to Financial Statements	F - 1
(2) Financial Statement Schedules – None	
(3) Exhibits – see Index to Exhibits	157

ITEM 16. FORM 10-K SUMMARY

None.

INDEX TO EXHIBITS

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

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of September 28, 2015, among Energy Transfer Corp LP, ETE Corp GP, LLC, Energy Transfer Equity, L.P., LE GP, LLC, ETE GP, LLC and The Williams Companies, Inc. (incorporated by reference to Exhibit 2.1 of Form 8-K/A, File No. 1-32740, filed October 2, 2015)
2.2	Agreement and Plan of Merger, dated as of November 20, 2016, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Sunoco Logistics Partners L.P., Sunoco Partners LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporate by reference to Exhibit 2.1 of Form 8-K File, No. 1-11727, filed November 21, 2016)
2.3	Amendment No. 1 to Agreement and Plan of Merger, dated as of December 16, 2016, by and among Sunoco Logistics Partners L.P., Sunoco Partners LLC, SXL Acquisition Sub LLC, SXL Acquisition Sub LP, Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., ETP Acquisition Sub, LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.2 of Form 8-K, File No. 1-11727, filed December 21, 2016)
2.4	Contribution Agreement, dated as of January 15, 2018, by and among USA Compression Partners, LP, Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., ETC Compression, LLC and, solely for certain purposes therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K, File No. 1-32740, filed January 16, 2018)
2.5	Purchase Agreement, dated as of January 15, 2018, by and among USA Compression Holdings, LLC, Energy Transfer Equity, L.P., Energy Transfer Partners, L.L.C. and, solely for certain purposes therein, R/C IV USACP Holdings, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 2.2 to Form 8-K, File No. 1-32740, filed January 16, 2018)
2.6	Agreement and Plan of Merger, dated as of August 1, 2018, by and among LE GP, LLC, Energy Transfer Equity, L.P., Streamline Merger Sub, LLC, Energy Transfer Partners, L.L.C. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 2.1 of Form 8-K, File No. 1-32740, filed August 3, 2018)
3.1	Certificate of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.2 of Form S-1, File No. 333-128097, filed September 2, 2005)
3.1.1	Certificate of Amendment to Certificate of Limited Partnership of Energy Transfer LP (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-32740, filed October 19, 2018)
3.2	Third Amended Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated February 8, 2006 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-32740, filed February 14, 2006)
3.3	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P. dated November 1, 2006 (incorporated by reference to Exhibit 3.3.1 of Form 10-K, File No. 1-32740, filed November 29, 2006)
3.4	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated November 9, 2007 (incorporated by reference to Exhibit 3.3.2 of Form 8-K, File No. 1-32740, filed November 13, 2007)
3.5	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated May 26, 2010 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-32740, filed June 2, 2010)
3.6	Amendment No. 4 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated December 23, 2013 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-32740, filed December 27, 2013)
3.7	Amendment No. 5 to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated as of March 8, 2016 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-32740, filed March 9, 2016)
3.8	Amendment No. 6 to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.2 of Form 8-K, File No.1-32740, filed October 19, 2018 (incorporated by reference to Exhibit 3.2 of Form 8-K, File No. 1-32740, filed October 19, 2018)
4.1	Indenture, dated September 20, 2010 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of Form 8-K, File No. 1-32740, filed September 20, 2010)
4.2	First Supplemental Indenture, dated September 20, 2010 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.2 of Form 8-K, File No. 1-32740, filed September 20, 2010)

Exhibit Number	Description
4.3	Second Supplemental Indenture, dated December 20, 2011 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 of Form S-3, File No. 1-32740, filed November 14, 2013)
4.4	Second Supplemental Indenture, dated February 16, 2012 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of Form 8-K, File No. 1-32740, filed February 17, 2012)
4.5	Fourth Supplemental Indenture, dated December 2, 2013 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.2 of Form 8-K, File No. 1-32740, filed December 2, 2013)
4.6	Fifth Supplemental Indenture, dated May 28, 2014 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of Form 8-K, File No. 1-32740, filed May 28, 2014)
4.7	Sixth Supplemental Indenture, dated May 28, 2014 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 of Form 8-K, File No. 1-32740, filed May 28, 2014)
4.8	Seventh Supplemental Indenture, dated May 22, 2015 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.2 of Form 8-K, File No. 1-32740, filed May 22, 2015)
4.9	Eighth Supplemental Indenture dated October 18, 2017 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of Form 8-K, File No. 1-32740, filed October 18th, 2017)
10.1+	Energy Transfer Equity, L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.25 of Form S-1, File No. 333-128097, filed December 20, 2005)
10.2+	Amended and Restated Energy Transfer LP Long-Term Incentive Plan (formerly Amended and Restated Energy Transfer Equity, L.P. Long-Term Incentive Plan) (incorporated by reference to 10.1 of Form 10-K, File No. 1-32740, filed February 23, 2018)
10.3+	Second Amended and Restated Energy Transfer LP 2008 Long-Term Incentive Plan (formerly Second Amended and Restated Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan) (incorporated by reference to Exhibit 4.1 of Form S-8 filed January 31, 2019)
10.4+	Energy Transfer LP 2011 Long-Term Incentive Plan (formerly Regency Energy Partners LP 2011 Long-Term Incentive Plan) (incorporated by reference to Exhibit 4.2 of Form S-8 filed January 31, 2019)
10.5+	Energy Transfer LP 2015 Long-Term Incentive Plan, as amended and restated (formerly Sunoco Partners LLC Long-Term Incentive Plan, as amended and restated) (incorporated by reference to Exhibit 4.3 of Form S-8 filed January 31, 2019)
10.6+	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.26 of Form S-1, File No. 333-128097, filed December 20, 2005)
10.7	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Equity, L.P. and Energy Transfer Investments, L.P. (incorporated by reference to Exhibit 10.38 of Form 10-K, File No. 1-32740, filed November 29, 2006)
10.8	Registration Rights Agreement, dated November 27, 2006, by and among Energy Transfer Equity, L.P. and certain investors named therein (incorporated by reference to Exhibit 99.1 of Form 8-K, File No. 1-32740, filed November 30, 2006)
10.9*+	LE GP, LLC Amended and Restated Outside Director Compensation Policy
10.10	Registration Rights Agreement, dated March 2, 2007, by and among Energy Transfer Equity, L.P. and certain investors named therein (incorporated by reference to Exhibit 99.1 of Form 8-K, File No. 1-32740, filed March 5, 2007)
10.11	Unitholder Rights and Restrictions Agreement, dated as of May 7, 2007, by and among Energy Transfer Equity, L.P., Ray C. Davis, Natural Gas Partners VI, L.P. and Enterprise GP Holdings, L.P. (incorporated by reference to Exhibit 10.45 of Form 8-K, File No. 1-32740, filed May 7, 2007)
10.12	Letter Agreement, dated as of April 29, 2012, by and among Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 1-32740, filed May 1, 2012)
10.13	Shared Services Agreement dated as of August 26, 2005, by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.30 of Form S-1/A (333-128097) filed December 20, 2005).
10.14	Second Amendment, dated April 30, 2013, to the Shared Services Agreement dated as of August 26, 2005, as amended May 26, 2010, by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P.(incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 1-32740, filed May 1, 2013)

Exhibit Number	Description
10.15	Third Amendment, dated February 19, 2014, to the Shared Services Agreement dated as of August 26, 2005, as amended May 26, 2010 and April 30, 2013 by and between Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 1-32740, filed February 19, 2014)
10.16	Credit Agreement, dated as of March 24, 2017 among Energy Transfer Equity, L.P., Credit Suisse AG, Cayman Islands Branch, as administrative agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 1-32740, filed March 30, 2017)
10.17	Class D Unit Agreement (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 1-32740, filed December 27, 2013)
10.18+	Retention Agreement, by and among Energy Transfer Equity, L.P. and Thomas P. Mason, dated February 24, 2016.
10.19	Senior Secured Term Loan Agreement, dated February 2, 2017 among Energy Transfer Equity, L.P., Credit Suisse AG, Cayman Islands Branch, as administrative agent, and the other lenders party hereto (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 1-32740, filed February 3, 2017.)
10.20	Equity Restructuring Agreement, dated as of January 15, 2018, by and among Energy Transfer Equity, L.P., USA Compression Partners, LP and USA Compression GP, LLC. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 16, 2018)
10.21	Registration Rights Agreement, dated as of April 2, 2018, by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P., USA Compression Partners, LP and USA Compression Holdings, LLC. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 3, 2018)
10.22+	Amended and Restated Energy Transfer Partners, L.L.C. Annual Bonus Plan (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 1-32740, filed August, 9 2018)
10.23*+	Energy Transfer LP Annual Bonus Plan
21.1*	List of Subsidiaries
23.1*	Consent of Grant Thornton LLP related to Energy Transfer LP
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2018 and December 31, 2017; (ii) our Consolidated Statements of Operations for the years ended December 31, 2018, 2017 and 2016; (iii) our Consolidated Statements of Comprehensive Income for years ended December 31, 2018, 2017 and 2016; (iv) our Consolidated Statement of Equity for the years ended December 31, 2018, 2017 and 2016; and (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016

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

SIGNATURES

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

ENERGY TRANSFER LP

By: LE GP, LLC, its general partner

Date: February 22, 2019

By: /s/ A. Troy Sturrock

A. Troy Sturrock

Senior Vice President, Controller and Principal Accounting Officer (duly authorized to sign on behalf of the registrant)

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

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 22, 2019
/s/ Thomas E. Long Thomas E. Long	Chief Financial Officer (Principal Financial Officer)	February 22, 2019
/s/ John W. McReynolds John W. McReynolds	Special Advisor and Director	February 22, 2019
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	President, Chief Commercial Officer and Director	February 22, 2019
/s/ Matthew S. Ramsey Matthew S. Ramsey	Chief Operating Officer and Director	February 22, 2019
/s/ A. Troy Sturrock A. Troy Sturrock	Senior Vice President and Controller (Principal Accounting Officer)	February 22, 2019
/s/ Steven R. Anderson Steven R. Anderson	Director	February 22, 2019
/s/ Richard D. Brannon Richard D. Brannon	Director	February 22, 2019
/s/ Ray C. Davis Ray C. Davis	Director	February 22, 2019
/s/ Michael K. Grimm Michael K. Grimm	Director	February 22, 2019

INDEX TO FINANCIAL STATEMENTS
Energy Transfer LP and Subsidiaries

	Page
Report of Independent Registered Public Accounting Firm	F - 2
Consolidated Balance Sheets	F - 3
Consolidated Statements of Operations	F - 5
Consolidated Statements of Comprehensive Income	F - 6
Consolidated Statements of Equity	F - 7
Consolidated Statements of Cash Flows	F - 9
Notes to Consolidated Financial Statements	F - 11

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of LE GP, LLC and
Unitholders of Energy Transfer LP

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Energy Transfer LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 22, 2019 expressed an unqualified opinion thereon.

Change in accounting principle
As discussed in Note 2 to the consolidated financial statements, the Partnership has changed its method of accounting for revenue from contracts with customers due to the adoption of the new revenue standard. The Partnership adopted the new revenue standard using the modified retrospective method.

Basis for opinion
These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2004.

Dallas, Texas
February 22, 2019

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31,	
	2018	2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 419	$ 336
Accounts receivable, net	4,009	4,504
Accounts receivable from related companies	111	53
Inventories	1,677	2,022
Income taxes receivable	73	136
Derivative assets	111	24
Other current assets	350	295
Current assets held for sale	—	3,313
Total current assets	6,750	10,683
Property, plant and equipment	79,776	71,177
Accumulated depreciation and depletion	(12,813)	(10,089)
	66,963	61,088
Advances to and investments in unconsolidated affiliates	2,642	2,705
Other non-current assets, net	1,006	886
Intangible assets, net	6,000	6,116
Goodwill	4,885	4,768
Total assets	$ 88,246	$ 86,246

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,493	$ 4,685
Accounts payable to related companies	59	31
Derivative liabilities	185	111
Accrued and other current liabilities	2,918	2,582
Current maturities of long-term debt	2,655	413
Current liabilities held for sale	—	75
Total current liabilities	9,310	7,897
Long-term debt, less current maturities	43,373	43,671
Non-current derivative liabilities	104	145
Deferred income taxes	2,926	3,315
Other non-current liabilities	1,184	1,217
Commitments and contingencies		
Redeemable noncontrolling interests	499	21
Equity:		
Limited Partners:		
Common Unitholders (2,619,368,605 and 1,079,145,561 units authorized, issued and outstanding as of December 31, 2018 and 2017, respectively)	20,606	(1,643)
Series A Convertible Preferred Units (329,295,770 units authorized, issued and outstanding as of December 31, 2017)	—	450
General Partner	(5)	(3)
Accumulated other comprehensive loss	(42)	—
Total partners' capital (deficit)	20,559	(1,196)
Noncontrolling interest	10,291	31,176
Total equity	30,850	29,980
Total liabilities and equity	$ 88,246	$ 86,246

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except per unit data)

	Years Ended December 31,		
	2018	2017	2016
REVENUES:			
Refined product sales	$ 18,345	$ 11,975	$ 10,097
Crude sales	14,415	10,706	7,205
NGL sales	9,109	6,972	4,841
Gathering, transportation and other fees	6,797	4,435	4,172
Natural gas sales	4,452	4,172	3,619
Other	969	2,263	1,858
Total revenues	54,087	40,523	31,792
COSTS AND EXPENSES:			
Cost of products sold	41,658	30,966	23,693
Operating expenses	3,089	2,644	2,336
Depreciation, depletion and amortization	2,859	2,554	2,216
Selling, general and administrative	702	599	656
Impairment losses	431	1,039	1,040
Total costs and expenses	48,739	37,802	29,941
OPERATING INCOME	5,348	2,721	1,851
OTHER INCOME (EXPENSE):			
Interest expense, net	(2,055)	(1,922)	(1,804)
Equity in earnings of unconsolidated affiliates	344	144	270
Impairment of investments in unconsolidated affiliates	—	(313)	(308)
Gains on acquisitions	—	—	83
Losses on extinguishments of debt	(112)	(89)	—
Gains (losses) on interest rate derivatives	47	(37)	(12)
Other, net	62	206	124
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	3,634	710	204
Income tax expense (benefit) from continuing operations	4	(1,833)	(258)
INCOME FROM CONTINUING OPERATIONS	3,630	2,543	462
Loss from discontinued operations, net of income taxes	(265)	(177)	(462)
NET INCOME	3,365	2,366	—
Less: Net income (loss) attributable to noncontrolling interest	1,632	1,412	(995)
Less: Net income attributable to redeemable noncontrolling interest	39	—	—
NET INCOME ATTRIBUTABLE TO PARTNERS	1,694	954	995
Convertible Unitholders’ interest in net income	33	37	9
General Partner’s interest in net income	3	2	3
Limited Partners’ interest in net income	$ 1,658	$ 915	$ 983
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:			
Basic	$ 1.17	$ 0.86	$ 0.95
Diluted	$ 1.16	$ 0.84	$ 0.93
NET INCOME PER LIMITED PARTNER UNIT:			
Basic	$ 1.16	$ 0.85	$ 0.94
Diluted	$ 1.15	$ 0.83	$ 0.92

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in millions)

	Years Ended December 31,		
	2018	2017	2016
Net income	$ 3,365	$ 2,366	$ —
Other comprehensive income (loss), net of tax:			
Change in value of available-for-sale securities	(4)	6	2
Actuarial loss relating to pension and other postretirement benefits	(43)	(12)	(1)
Foreign currency translation adjustment	—	—	(1)
Change in other comprehensive income from unconsolidated affiliates	4	1	4
	(43)	(5)	4
Comprehensive income	3,322	2,361	4
Less: Comprehensive income (loss) attributable to noncontrolling interest	1,632	1,407	(991)
Less: Comprehensive income attributable to redeemable noncontrolling interest	39	—	—
Comprehensive income attributable to partners	$ 1,651	$ 954	$ 995

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

	Series A Convertible Preferred Units	Class D Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
Balance, December 31, 2015	$ —	$ 22	$ (952)	$ (2)	$ —	$ 24,485	$ 23,553
Distributions to partners	—	—	(1,019)	(3)	—	—	(1,022)
Distributions to noncontrolling interest	—	—	—	—	—	(2,795)	(2,795)
Distributions reinvested	173	—	(173)	—	—	—	—
Subsidiary units issued for cash	—	—	—	—	—	2,559	2,559
Subsidiary units issued for acquisition	—	—	—	—	—	307	307
Issuance of common units	(2)		39	—	—	—	37
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	(22)	—	—	—	74	52
Capital contributions received from noncontrolling interest	—	—	—	—	—	236	236
Acquisition and disposition of noncontrolling interest	—	—	(779)	—	—	—	(779)
PennTex Acquisition	—	—	—	—	—	236	236
Other comprehensive income, net of tax	—	—	—	—	—	4	4
Other, net	—	—	30	(1)	—	14	43
Net income (loss)	9	—	983	3	—	(995)	—
Balance, December 31, 2016	$ 180	$ —	$ (1,871)	$ (3)	$ —	$ 24,125	$ 22,431
Distributions to partners	—	—	(1,008)	(2)	—	—	(1,010)
Distributions to noncontrolling interest	—	—	—	—	—	(2,999)	(2,999)
Distributions reinvested	234	—	(234)	—	—	—	—
Units issuance	—	—	568	—	—	—	568
Subsidiary units issued for cash	(1)	—	(55)	—	—	3,291	3,235
Non-cash compensation expense, net of units tendered by employees for tax withholdings	—	—	—	—	—	86	86
Capital contributions received from noncontrolling interest	—	—	—	—	—	2,202	2,202
Other, net	—	—	—	—	—	(92)	(92)
PennTex unit acquisition	—	—	(2)	—	—	(278)	(280)
Sale of Bakken Pipeline interest	—	—	42	—	—	1,958	2,000
Sale of Rover Pipeline interest	—	—	2	—	—	1,476	1,478
Other comprehensive loss, net of tax	—	—	—	—	—	(5)	(5)
Net income	37	—	915	2	—	1,412	2,366
Balance, December 31, 2017	$ 450	$ —	$ (1,643)	$ (3)	$ —	$ 31,176	$ 29,980
Distributions to partners	—	—	(1,681)	(3)	—	—	(1,684)
Distributions to noncontrolling interest	—	—	—	—	—	(3,117)	(3,117)
Distributions reinvested	115	—	(115)	—	—		—
Subsidiary units repurchased	(7)	—	(119)	—	—	102	(24)
Subsidiary units issued	—	—	1	—	—	923	924

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

Energy Transfer Merger	—	—	21,869	—	—	(21,869)	—
Capital contributions received from noncontrolling interest	—	—	—	—	—	649	649
Other comprehensive loss, net of tax	—	—	—	—	(43)	—	(43)
Cumulative effect adjustment due to change in accounting principle (see Note 2)	—	—	—	—	—	(54)	(54)
Acquisition of USAC NCI	—	—	—	—	—	832	832
ET Series A Convertible Preferred Units conversion	(589)	—	589	—	—	—	—
Other, net	(2)	—	47	(2)	1	17	61
Net income, excluding amounts attributable to redeemable noncontrolling interests	33	—	1,658	3	—	1,632	3,326
Balance, December 31, 2018	$ —	$ —	$ 20,606	$ (5)	$ (42)	$ 10,291	$ 30,850

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2018	2017	2016
OPERATING ACTIVITIES:			
Net income	$ 3,365	$ 2,366	$ —
Reconciliation of net income to net cash provided by operating activities:			
Loss from discontinued operations	265	177	462
Depreciation, depletion and amortization	2,859	2,554	2,216
Deferred income taxes	(7)	(1,871)	(177)
Inventory valuation adjustments	85	(24)	(97)
Non-cash compensation expense	105	99	70
Impairment losses	431	1,039	1,040
Impairment of investments in unconsolidated affiliates	—	313	308
Gains on acquisitions	—	—	(83)
Losses on extinguishments of debt	112	89	—
Distributions on unvested awards	(38)	(35)	(29)
Distributions from unconsolidated affiliates	328	297	268
Equity in earnings of unconsolidated affiliates	(344)	(144)	(270)
Other non-cash	56	(239)	(207)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	289	(192)	(179)
Net cash provided by operating activities	7,506	4,429	3,322
INVESTING ACTIVITIES:			
Cash received in USAC acquisition, net of cash paid	461	—	—
Proceeds from sale of Bakken Pipeline interest	—	2,000	—
Proceeds from sale of Rover Pipeline interest	—	1,478	—
Cash paid for acquisition of PennTex noncontrolling interest	—	(280)	—
Cash paid for Vitol Acquisition, net of cash received	—	—	(769)
Cash paid for PennTex Acquisition, net of cash received	—	—	(299)
Cash paid for acquisitions, net of cash received	(429)	(303)	(330)
Capital expenditures, excluding allowance for equity funds used during construction	(7,407)	(8,444)	(7,771)
Contributions in aid of construction costs	109	31	71
Contributions to unconsolidated affiliates	(26)	(268)	(68)
Distributions from unconsolidated affiliates in excess of cumulative earnings	69	135	135
Proceeds from the sale of other assets	87	48	35
Change in restricted cash	—	—	14
Other	61	(3)	—
Net cash used in investing activities	(7,075)	(5,606)	(8,982)
FINANCING ACTIVITIES:			
Proceeds from borrowings	29,001	31,608	25,785
Repayments of long-term debt	(28,948)	(31,268)	(19,076)
Cash (paid) received on affiliate notes	—	(255)	266
Units issued for cash	—	568	—
Subsidiary units issued for cash	1,402	3,235	2,559

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

Capital contributions from noncontrolling interest	649	1,214	236
Distributions to partners	(1,684)	(1,010)	(1,022)
Distributions to noncontrolling interests	(3,117)	(2,961)	(2,766)
Distributions to redeemable noncontrolling interest	(24)	—	—
Subsidiary units repurchased	(24)	—	—
Redemption of preferred units	—	(53)	—
Debt issuance costs	(171)	(131)	(52)
Other, net	(166)	6	(3)
Net cash (used in) provided by financing activities	(3,082)	953	5,927
DISCONTINUED OPERATIONS			
Operating activities	(484)	136	93
Investing activities	3,207	(38)	(483)
Changes in cash included in current assets held for sale	11	(5)	5
Net increase (decrease) in cash and cash equivalents of discontinued operations	2,734	93	(385)
Increase (decrease) in cash and cash equivalents	83	(131)	(118)
Cash and cash equivalents, beginning of period	336	467	585
Cash and cash equivalents, end of period	$ 419	$ 336	$ 467

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

ENERGY TRANSFER LP 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 LP and its subsidiaries (the "Partnership," "we," "us," "our" or "ET"). References to the "Parent Company" mean Energy Transfer LP on a stand-alone basis.

In October 2018, we completed the merger of ETO with a wholly-owned subsidiary of ET in a unit-for-unit exchange (the "Energy Transfer Merger"). In connection with the transaction, ETO unitholders (other than ET and its subsidiaries) received 1.28 common units of ET for each common unit of ETO they owned.

Immediately prior to the closing of the Energy Transfer Merger, the following also occurred:

- the IDRs in Energy Transfer Partners, L.P. were converted into 1,168,205,710 Energy Transfer Partners, L.P. common units; and
- the general partner interest in ETO was converted to a non-economic general partner interest and Energy Transfer Partners, L.P. issued 18,448,341 Energy Transfer Partners, L.P. common units to ETP GP.

Following the closing of the Energy Transfer Merger, Energy Transfer Equity, L.P. changed its name to "Energy Transfer LP" and its common units began trading on the New York Stock Exchange under the "ET" ticker symbol on Friday, October 19, 2018. In addition, Energy Transfer Partners, L.P. changed its name to "Energy Transfer Operating, L.P." For purposes of maintaining clarity, the following references are used herein:

- References to "ETO" refer to the entity named Energy Transfer Partners, L.P. prior to the close of the Energy Transfer Merger and Energy Transfer Operating, L.P. subsequent to the close of the Energy Transfer Merger; and
- References to "ET" refer to the entity named Energy Transfer Equity, L.P. prior to the close of the Energy Transfer Merger and Energy Transfer LP subsequent to the close of the Energy Transfer Merger.

In April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed the previously announced merger transaction in which Sunoco Logistics acquired Energy Transfer Partners, L.P. in a unit-for-unit transaction (the "Sunoco Logistics Merger"). Under the terms of the transaction, Energy Transfer Partners, L.P. unitholders received 1.5 common units of Sunoco Logistics for each common unit of Energy Transfer Partners, L.P. 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 ET. In connection with the merger, the Energy Transfer Partners, L.P. Class H units were cancelled. The outstanding Energy Transfer Partners, L.P. 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 Energy Transfer Partners, L.P. 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 Energy Transfer Partners, L.P. at the effective time of the merger were cancelled. In connection with the Sunoco Logistics Merger, Sunoco Logistics Partners L.P. changed its name to "Energy Transfer Partners, L.P." References to "Sunoco Logistics" refer to the entity named Sunoco Logistics Partners L.P. prior to the close of the Sunoco Logistics Merger.

Subsequent to the Energy Transfer Merger, substantially all of the Partnership's cash flows are derived from distributions related to its investment in ETO, whose cash flows are derived from its subsidiaries, including ETO's investments in Sunoco LP and USAC. The Parent Company's primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. Parent Company-only assets are not available to satisfy the debts and other obligations of ET's subsidiaries. In order to understand the financial condition of the Parent Company on a stand-alone basis, see Note 18 for stand-alone financial information apart from that of the consolidated partnership information included herein.

Our 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;
- investment in Sunoco LP;
- investment in USAC; and
- corporate and other, including the following:
  - activities of the Parent Company; and
  - certain operations and investments that are not separately reflected as reportable segments.

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 owns and operates intrastate natural gas pipeline systems and storage facilities 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 and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets, which are used to facilitate the purchase and sale of crude oil, NGLs and refined products.

The Partnership owns a controlling interest in Sunoco LP which is engaged in the wholesale distribution of motor fuels to convenience stores, independent dealers, commercial customers, and distributors, as well as the retail sale of motor fuels and merchandise through Sunoco LP operated convenience stores and retail fuel sites. As of December 31, 2018, our interest in Sunoco LP consisted of 100% of the general partner and IDRs, as well as 28.5 million common units.

The Partnership owns a controlling interest in USAC which provides compression services to producers, processors, gatherers and transporters of natural gas and crude oil. As of December 31, 2018, our interest in USAC consisted of 39.7 million common units and 6.4 million Class B units.

Basis of Presentation. The consolidated financial statements of Energy Transfer LP presented herein for the years ended December 31, 2018, 2017 and 2016, have been prepared in accordance with GAAP and pursuant to the rules and regulations of the SEC. We consolidate all majority-owned subsidiaries and limited partnerships, which we control as the general partner or owner of the general partner. All significant intercompany transactions and accounts are eliminated in consolidation.

The consolidated financial statements of ET presented herein include the results of operations of:

- the Parent Company;
- our controlled subsidiary, Energy Transfer Operating, L.P. ("ETO");
- Energy Transfer Partners GP, L.P. ("ETP GP"), the general partner of ETO, and Energy Transfer Partners, L.L.C. ("ETP LLC"), the general partner of ETP GP.

Our subsidiaries also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

For prior periods herein, certain balances have been reclassified to assets and liabilities held for sale and certain revenues and expenses to discontinued operations. These reclassifications had no impact on net income or total equity.

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

Use of Estimates

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

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

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

Revenue Recognition

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. The Partnership adopted ASU 2014-09 on January 1, 2018.

Upon the adoption of ASU 2014-09, the amount of revenue that the Partnership recognizes on certain contracts has changed, primarily due to decreases in revenue (with offsetting decreases to cost of sales) resulting from recognition of non-cash consideration as revenue when received and as cost of sales when sold to third parties. In addition, income statement reclassifications were required for fuel usage and loss allowances related to multiple segments as well as contracts deemed to be in-substance supply agreements in our midstream segment. In addition to the evaluation performed, we have made appropriate design and implementation updates to our business processes, systems and internal controls to support recognition and disclosure under the new standard.

Utilizing the practical expedients allowed under the modified retrospective adoption method, Accounting Standards Codification ("ASC") Topic 606 was only applied to existing contracts for which the Partnership has remaining performance obligations as of January 1, 2018, and new contracts entered into after January 1, 2018. ASC Topic 606 was not applied to contracts that were completed prior to January 1, 2018.

The Partnership has elected to apply the modified retrospective method to adopt the new standard. For contracts in scope of the new revenue standard as of January 1, 2018, the cumulative effect adjustment to partners' capital was not material. The comparative information has not been restated under the modified retrospective method and continues to be reported under the accounting standards in effect for those periods.

For contracts in scope of the new revenue standard as of January 1, 2018, the Partnership recognized a cumulative effect adjustment to retained earnings to account for the differences in timing of revenue recognition. The comparative information has not been restated under the modified retrospective method and continues to be reported under the accounting standards in effect for those periods.

The adjustments to the opening balance sheet primarily relate to a change in timing of revenue recognition for variable consideration at Sunoco LP, such as incentives paid to customers, as well as a change in timing of revenue recognition for franchise fee revenue. Historically, an asset was recognized related to the contract incentives which was amortized over the life of the agreement. Under the new standard, the timing of the recognition of incentives changed due to application of the expected value method to estimate variable consideration. Additionally, under the new standard the change in timing of franchise fee revenue is due to the treatment of revenue recognition from the symbolic license over the term of the agreement.

The cumulative effect of the changes made to the Partnership's consolidated balance sheet for the adoption of ASU 2014-09 was as follows:

	Balance at December 31, 2017	Adjustments due to ASC 606	Balance at January 1, 2018
Assets:			
Other current assets	$ 295	$ 8	$ 303
Property, plant and equipment, net	61,088	—	61,088
Intangible assets, net	6,116	(100)	6,016
Other non-current assets, net	886	39	925
Liabilities and Equity:			
Other non-current liabilities	$ 1,217	$ 1	$ 1,218
Noncontrolling interest	31,176	(54)	31,122

The adoption of the new revenue standard resulted in reclassifications between revenue, cost of sales and operating expenses. Additionally, changes in timing of revenue recognition have required the creation of contract asset or contract liability balances, as well as certain balance sheet reclassifications. In accordance with the requirements of ASC Topic 606, the disclosure below shows the impact of adopting the new standard on the consolidated statement of operations and the consolidated balance sheet.

	Year Ended December 31, 2018		
	As Reported	Balances Without Adoption of ASC 606	Effect of Change: Higher/ (Lower)
Revenues:			
Natural gas sales	$ 4,452	$ 4,452	$ —
NGL sales	9,109	9,071	38
Crude sales	14,415	14,403	12
Gathering, transportation and other fees	6,797	7,526	(729)
Refined product sales	18,345	18,393	(48)
Other	969	968	1
Costs and expenses:			
Cost of products sold	$ 41,658	$ 42,389	$ (731)
Operating expenses	3,089	3,045	44
Depreciation and amortization	2,859	2,888	(29)

	Year Ended December 31, 2018		
	As Reported	Balances Without Adoption of ASC 606	Effect of Change: Higher/ (Lower)
Assets:			
Other current assets	$ 350	$ 338	$ 12
Property, plant and equipment, net	66,963	66,963	—
Other non-current assets, net	1,006	947	59
Intangible assets, net	6,000	6,134	(134)
Liabilities and Equity:			
Other non-current liabilities	$ 1,184	$ 1,183	$ 1
Noncontrolling interest	10,291	10,355	(64)

Additional disclosures related to revenue recognition are included in Note 12.

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, dispositions and deconsolidation) included in cash flows from operating activities was comprised as follows:

	Years Ended December 31,		
	2018	2017	2016
Accounts receivable	$ 541	$ (948)	$ (1,126)
Accounts receivable from related companies	162	24	42
Inventories	282	58	(480)
Other current assets	7	38	165
Other non-current assets, net	(92)	84	(148)
Accounts payable	(766)	712	1,170
Accounts payable to related companies	(202)	(178)	(64)
Accrued and other current liabilities	382	(97)	89
Other non-current liabilities	28	106	106
Derivative assets and liabilities, net	(53)	9	67
Net change in operating assets and liabilities, net of effects of acquisitions	$ 289	$ (192)	$ (179)

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

	Years Ended December 31,		
	2018	2017	2016
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 1,030	$ 1,060	$ 848
Net gains (losses) from subsidiary common unit transactions	(126)	(56)	16
NON-CASH FINANCING ACTIVITIES:			
Issuance of Common Units in connection with the PennTex Acquisition	$ —	$ —	$ 307
Contribution of assets from noncontrolling interest	—	988	—
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,870	$ 1,914	$ 1,922
Cash paid for (refund of) income taxes	508	50	(229)

Accounts Receivable

Our 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.

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, NGLs and refined products, crude oil and spare parts, all of which are valued at the lower of cost or net realizable value utilizing the weighted-average cost method.

Inventories consisted of the following:

	December 31,	
	2018	2017
Natural gas, NGLs and refined products [(1)]	$ 833	$ 1,120
Crude oil	506	551
Spare parts and other	338	351
Total inventories	$ 1,677	$ 2,022

(1) Due to changes in fuel prices, Sunoco LP recorded a write-down on the value of its fuel inventory of $85 million as of December 31, 2018.

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,	
	2018	2017
Deposits paid to vendors	$ 141	$ 64
Prepaid expenses and other	209	231
Total other current assets	$ 350	$ 295

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 2018, USAC recognized a $9 million fixed asset impairment related to certain idle compressor assets.

In 2017, the Partnership recorded a $127 million fixed asset impairment related to Sea Robin primarily due to a reduction in expected future cash flows due to an increase during 2017 in insurance costs related to offshore assets.

In 2016, the Partnership recorded a $133 million fixed asset impairment related to its 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 its midstream segment.

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 facilities 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, 2018	December 31, 2017
Land and improvements	$ 2,146	$ 2,222
Buildings and improvements (1 to 45 years)	2,664	2,786
Pipelines and equipment (5 to 83 years)	57,584	44,673
Natural gas and NGL storage facilities (5 to 46 years)	1,898	1,681
Bulk storage, equipment and facilities (2 to 83 years)	3,395	3,036
Tanks and other equipment (5 to 40 years)	884	847
Vehicles (1 to 25 years)	123	126
Right of way (20 to 83 years)	3,555	3,432
Natural resources	434	434
Other (1 to 40 years)	1,026	1,029
Construction work-in-process	6,067	10,911
	79,776	71,177
Less – Accumulated depreciation and depletion	(12,813)	(10,089)
Property, plant and equipment, net	$ 66,963	$ 61,088

We recognized the following amounts for the periods presented:

	Years Ended December 31, 2018	2017	2016
Depreciation, depletion and amortization expense	$ 2,538	$ 2,204	$ 1,952
Capitalized interest	294	286	201

Advances to and Investments in 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. An impairment of an investment in an unconsolidated affiliate is recognized when circumstances indicate that a decline in the investment value is other than temporary.

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, 2018	December 31, 2017
Regulatory assets	43	85
Deferred charges	241	210
Restricted funds	178	192
Other	544	399
Total other non-current assets, net	$ 1,006	$ 886

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, 2018		December 31, 2017	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 7,106	$ (1,493)	$ 6,979	$ (1,277)
Patents (10 years)	48	(30)	48	(26)
Trade names (20 years)	66	(28)	66	(25)
Other (5 to 20 years)	33	(9)	28	(14)
Total amortizable intangible assets	7,253	(1,560)	7,121	(1,342)
Non-amortizable intangible assets:				
Trademarks	295	—	295	—
Other	12	—	42	—
Total non-amortizable intangible assets	307	—	337	—
Total intangible assets	$ 7,560	$ (1,560)	$ 7,458	$ (1,342)

Aggregate amortization expense of intangibles assets was as follows:

	Years Ended December 31,		
	2018	2017	2016
Reported in depreciation, depletion and amortization expense	$ 321	$ 344	$ 264

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

Years Ending December 31:	
2019	$ 346
2020	345
2021	342
2022	325
2023	319

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.

Sunoco LP performed impairment tests on its indefinite-lived intangible assets during the fourth quarter of 2018 and recognized a $30 million impairment charge on its contractual rights, included in other in the table above, primarily due to decreases in projected future revenues and cash flows from the date the intangible asset was originally recorded.

Sunoco LP performed impairment tests on its indefinite-lived intangible assets during the fourth quarter of 2017 and recognized $13 million and $4 million impairment charge on their contractual rights and liquor licenses, included in other in the table above, primarily due to decreases in projected future revenues and cash flows from the date the intangible asset was originally recorded.

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	Investment in Sunoco LP	Investment in USAC	All Other	Total
Balance, December 31, 2016	$ 10	$ 458	$ 863	$ 772	$ 1,163	$ 1,550	$ —	$ 854	$ 5,670
Acquired	—	—	8	—	4	—	—	—	12
Impaired	—	(262)	—	(79)	—	(102)	—	(452)	(895)
Other	—	—	(1)	—	—	(18)	—	—	(19)
Balance, December 31, 2017	10	196	870	693	1,167	1,430	—	402	4,768
Acquired	—	—	—	—	—	129	366	—	495
CDM Contribution	—	—	—	—	—	—	253	(253)	—
Impaired	—	—	(378)	—	—	—	—	—	(378)
Other	—	—	—	—	—	—	—	—	—
Balance, December 31, 2018	$ 10	$ 196	$ 492	$ 693	$ 1,167	$ 1,559	$ 619	$ 149	$ 4,885

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.

As of December 31, 2018, ETO's ETC Marketing reporting unit, to which $72 million of goodwill is allocated, had a negative carrying amount. The reporting unit is in the all other segment.

During the fourth quarter of 2018, the Partnership recognized goodwill impairments of $378 million related to our Northeast operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded. These changes in assumptions reflect delays in the construction of third-party takeaway capacity in the Northeast.

During the fourth quarter of 2017, the Partnership recognized goodwill impairments of $262 million in the interstate transportation and storage segment, $79 million in the NGL and refined products transportation and services segment and $452 million in the all other segment primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded. Sunoco LP recognized goodwill impairments of $387 million, of which $102 million was allocated to continuing operations, primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

During the fourth quarter of 2016, the Partnership recognized goodwill impairments of $638 million in 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. Sunoco LP recognized goodwill impairments of $641 million, of which $227 million was allocated to continuing operations, primarily due to changes in assumptions related to projected future revenues and cash flows from the dates the goodwill was originally recorded.

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 discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2018 and 2017, 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 AROs 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. We believe we may have additional AROs related to Sunoco, Inc.'s pipeline assets and storage tanks, for which it is not possible to estimate whether or when the AROs will be settled. Consequently, these AROs cannot be measured at this time. Sunoco LP has AROs related to the estimated future cost to remove underground storage tanks.

As of December 31, 2018 and 2017, other non-current liabilities in the Partnership's consolidated balance sheets included AROs of $193 million and $220 million, respectively. For the years ended December 31, 2018, 2017 and 2016 aggregate accretion expense related to AROs was $13 million, $9 million and $7 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 $106 million and $103 million and were reflected as property, plant and equipment on our consolidated balance sheet as of December 31, 2018 and 2017, respectively. In addition, other non-current assets on the Partnership's consolidated balance sheet included $26 million and $21 million of legally restricted funds for the purpose of settling AROs as of December 31, 2018 and 2017, respectively.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2018	2017
Interest payable	$ 571	$ 552
Customer advances and deposits	128	59
Accrued capital expenditures	1,030	1,006
Accrued wages and benefits	283	280
Taxes payable other than income taxes	256	288
Exchanges payable	112	154
Other	538	243
Total accrued and other current liabilities	$ 2,918	$ 2,582

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

Redeemable Noncontrolling Interests

Our redeemable noncontrolling interests relate to certain preferred unitholders of one of our consolidated subsidiaries that have the option to convert their preferred units to such subsidiary's common units at the election of the holders and the noncontrolling interest holders in one of our consolidated subsidiaries that have the option to sell their interests to us. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable noncontrolling interests on our consolidated balance sheet. See Note 7 for further information.

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 consolidated debt obligations as of December 31, 2018 was $45.06 billion and $46.03 billion, respectively. As of December 31, 2017, the aggregate fair value and carrying amount of our consolidated debt obligations was $45.62 billion and $44.08 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. During the year ended December 31, 2018 and 2017, 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, 2018 and 2017 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at December 31, 2018	
		Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 42	$ 42	$ —
Swing Swaps IFERC	52	8	44
Fixed Swaps/Futures	97	97	—
Forward Physical Contracts	20	—	20
Power:			
Forwards	48	—	48
Futures	1	1	—
Options – Calls	1	1	—
NGLs – Forwards/Swaps	291	291	—
Refined Products – Futures	7	7	—
Crude – Forwards/Swaps	1	1	—
Total commodity derivatives	560	448	112
Other non-current assets	26	17	9
Total assets	$ 586	$ 465	$ 121
Liabilities:			
Interest rate derivatives	$ (163)	$ —	$ (163)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(91)	(91)	—
Swing Swaps IFERC	(40)	—	(40)
Fixed Swaps/Futures	(88)	(88)	—
Forward Physical Contracts	(21)	—	(21)
Power:			
Forwards	(42)	—	(42)
Futures	(1)	(1)	—
NGLs – Forwards/Swaps	(224)	(224)	—
Refined Products – Futures	(15)	(15)	—
Crude – Forwards/Swaps	(61)	(61)	—
Total commodity derivatives	(583)	(480)	(103)
Total liabilities	$ (746)	$ (480)	$ (266)

	Fair Value Total	Fair Value Measurements at December 31, 2017	
		Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 11	$ 11	$ —
Swing Swaps IFERC	13	—	13
Fixed Swaps/Futures	70	70	—
Forward Physical Contracts	8	—	8
Power – Forwards	23	—	23
NGLs – Forwards/Swaps	191	191	—
Refined Products – Futures	1	1	—
Crude:			
Forwards/Swaps	2	2	—
Futures	2	2	—
Total commodity derivatives	321	277	44
Other non-current assets	21	14	7
Total assets	$ 342	$ 291	$ 51
Liabilities:			
Interest rate derivatives	$ (219)	$ —	$ (219)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(24)	(24)	—
Swing Swaps IFERC	(15)	(1)	(14)
Fixed Swaps/Futures	(57)	(57)	—
Forward Physical Contracts	(2)	—	(2)
Power – Forwards	(22)	—	(22)
NGLs – Forwards/Swaps	(186)	(186)	—
Refined Products – Futures	(28)	(28)	—
Crude:			
Forwards/Swaps	(6)	(6)	—
Futures	(1)	(1)	—
Total commodity derivatives	(341)	(303)	(38)
Total liabilities	$ (560)	$ (303)	$ (257)

Contributions in Aid of Construction Cost

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

Shipping and Handling Costs

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

Costs and Expenses

Cost 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. Excise taxes collected by Sunoco LP's retail locations where Sunoco LP holds the inventory were $370 million, $234 million and $243 million for the years ended December 31, 2018, 2017 and 2016, 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

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

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and Internal Revenue Service ("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, ET would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2018, 2017 and 2016, 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, Inland Corporation, Sunoco Property Company LLC and Aloha Petroleum. 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.

Non-Cash 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

The Partnership recognizes 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. Changes in the funded status of the plan are recorded 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. In 2018, the Company adopted Accounting Standards Update No. 2017-07 *Compensation - Retirement Benefits* (Topic 715) retrospectively. It requires the service cost component to be presented with other current compensation costs for the related employees in the operating section of our consolidated statements of operations, with other components of net benefit cost presented outside of the operating income.

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.

Recent Accounting Pronouncements

ASU 2016-02

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 information about the amount, timing, and uncertainty of cash flows arising from a lease. The update requires lessees to record virtually all leases on their balance sheets. For lessors, this amended guidance modifies the classification criteria and the accounting for sales-type and direct financing leases. In

January 2018, the FASB issued Accounting Standards Update No. 2018-01 ("ASU 2018-01"), which provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the existing lease guidance. The Partnership plans to elect the package of transition practical expedients and will adopt this standard beginning with its first quarter of fiscal 2019 and apply it retrospectively at the beginning of the period of adoption through a cumulative-effect adjustment to retained earnings. The Partnership has performed several procedures to evaluate the impact of the adoption of this standard on the financial statements and disclosures and address the implications of Topic 842 on future lease arrangements. The procedures include reviewing all forms of leases, performing a completeness assessment over the lease population, establishing processes and controls to timely identify new and modified lease agreements, educating its employees on these new processes and controls and implementing a third-party supported lease accounting information system to account for our leases in accordance with the new standard. The Partnership is finalizing its evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements, and estimates approximately $1.0 billion of right-to-use assets and lease liabilities will be recognized in the consolidated balance sheet upon adoption, with no material impact to its consolidated statements of operations.

ASU 2017-12

In August 2017, the FASB issued Accounting Standards Update No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.* The amendments in this update improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition, the amendments in this update make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP. This ASU is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. The Partnership expects to adopt the new rules in the first quarter of 2019 and does not expect the adoption of the new accounting rules to have a material impact on the consolidated financial statements and related disclosures.

ASU 2018-02

In February 2018, the FASB issued Accounting Standards Update No. 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*, which allows a reclassification from accumulated other comprehensive income to partners' capital for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. The Partnership elected to early adopt this ASU in the first quarter of 2018. The effect of the adoption was not material.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2018 Transactions

ET Contribution of Assets to ETO

Immediately prior to the closing of the Energy Transfer Merger discussed in Note 1, ET contributed the following to ETO:

- 2,263,158 common units representing limited partner interests in Sunoco LP to ETO in exchange for 2,874,275 ETO common units;
- 100 percent of the limited liability company interests in Sunoco GP LLC, the sole general partner of Sunoco LP, and all of the IDRs in Sunoco LP, to ETO in exchange for 42,812,389 ETO common units;
- 12,466,912 common units representing limited partner interests in USAC and 100 percent of the limited liability company interests in USA Compression GP, LLC, the general partner of USAC, to ETO in exchange for 16,134,903 ETO common units; and
- a 100 percent limited liability company interest in Lake Charles LNG and a 60 percent limited liability company interest in each of Energy Transfer LNG Export, LLC, ET Crude Oil Terminals, LLC and ETC Illinois LLC (collectively, "Lake Charles LNG and Other") to ETO in exchange for 37,557,815 ETO common units.

USAC Acquisition

On April 2, 2018, ET acquired a controlling interest in USAC, a publicly traded partnership that provides compression services in the United States. Specifically the Partnership acquired (i) all of the outstanding limited liability company interests in USA Compression GP, LLC ("USAC GP"), the general partner of USAC, and (ii) 12,466,912 USAC common units representing limited partner interests in USAC for cash consideration equal to $250 million (the "USAC Transaction"). Concurrently, USAC cancelled its incentive distribution rights and converted its economic general partner interest into a non-economic general partner interest in exchange for the issuance of 8,000,000 USAC common units to USAC GP.

Concurrent with these transactions, ETO contributed to USAC all of the issued and outstanding membership interests of CDM for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 USAC common units, (ii) 6,397,965 units of a new class of units representing limited partner interests in USAC ("USAC Class B Units") and (iii) $1.23 billion in cash, including customary closing adjustments (the "CDM Contribution"). The USAC Class B Units have substantially all of the rights and obligations of a USAC common unit, except the USAC Class B Units will not participate in distributions for the first four quarters following the closing date of April 2, 2018. Each USAC Class B Unit will automatically convert into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019.

Prior to the USAC acquisition, the CDM entities were indirect wholly-owned subsidiaries of ETO.

Summary of Assets Acquired and Liabilities Assumed

The USAC Transaction was recorded 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 April 2, 2018
Total current assets	$ 786
Property, plant and equipment	1,332
Other non-current assets	15
Goodwill(1)	366
Intangible assets	222
Total assets	2,721
Total current liabilities	110
Long-term debt, less current maturities	1,527
Other non-current liabilities	2
Total liabilities	1,639
Noncontrolling interest	832
Total consideration	250
Cash received(2)	711
Total consideration, net of cash received(2)	$ (461)

(1) None of the goodwill is expected to be deductible for tax purposes. Goodwill recognized from the business combination primarily relates to the value attributed to additional growth opportunities, synergies and operating leverage within USAC's operations.

(2) Cash received represents cash and cash equivalents held by USAC as of the acquisition date.

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

Sunoco LP Convenience Store and Real Estate Sale

On January 23, 2018, Sunoco LP completed the disposition of assets pursuant to the purchase agreement with 7-Eleven, Inc. (the "7-Eleven Transaction"). As a result of the 7-Eleven Transaction, previously eliminated wholesale motor fuel sales to Sunoco LP's retail locations are reported as wholesale motor fuel sales to third parties. Also, the related accounts receivable from such sales are no longer eliminated from the Partnership's consolidated balance sheets and are reported as accounts receivable.

In connection with the 7-Eleven Transaction, Sunoco LP entered into a Distributor Motor Fuel Agreement dated as of January 23, 2018 ("Supply Agreement"), with 7-Eleven and SEI Fuel (collectively, "Distributor"). The Supply Agreement consists of a 15-year take-or-pay fuel supply arrangement under which Sunoco LP has agreed to supply approximately 2.0 billion gallons of fuel annually plus additional aggregate growth volumes of up to 500 million gallons to be added incrementally over the first four years. For the period from January 1, 2018 through January 22, 2018 and the years ended December 31, 2017 and 2016, Sunoco LP recorded sales to the sites that were subsequently sold to 7-Eleven of $199 million, $3.2 billion and $2.6 billion, respectively, which were eliminated in consolidation. Sunoco LP received payments on trade receivables of $3.4 billion from 7-Eleven for the year ended December 31, 2018 subsequent to the closing of the sale.

On January 18, 2017, with the assistance of a third-party brokerage firm, Sunoco LP launched a portfolio optimization plan to market and sell 97 real estate assets. Real estate assets included in this process are company-owned locations, undeveloped greenfield sites and other excess real estate. Properties are located in Florida, Louisiana, Massachusetts, Michigan, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas and Virginia. The properties are being sold through a sealed-bid. Of the 97 properties, 51 have been sold, one is under contract to be sold, and four continue to be marketed by the third-party brokerage firm. Additionally, 32 were sold to 7-Eleven and nine are part of the approximately 207 retail sites located in certain West Texas, Oklahoma, and New Mexico markets which are operated by a commission agent.

The Partnership has concluded that it meets the accounting requirements for reporting the financial position, results of operations and cash flows of Sunoco LP's retail divestment as discontinued operations.

The following tables present the aggregate carrying amounts of assets and liabilities classified as held for sale in the consolidated balance sheet:

	December 31, 2018	December 31, 2017
Carrying amount of assets included as part of discontinued operations:		
Accounts receivable, net	$ —	$ 21
Inventories	—	149
Other current assets	—	16
Property and equipment, net	—	1,851
Goodwill	—	796
Intangible assets, net	—	477
Other noncurrent assets	—	3
Total assets classified as held for sale in the Consolidated Balance Sheet	$ —	$ 3,313
Carrying amount of liabilities included as part of discontinued operations:		
Other current and noncurrent liabilities	$ —	$ 75
Total liabilities classified as held for sale in the Consolidated Balance Sheet	$ —	$ 75

The results of operations associated with discontinued operations are presented in the following table:

	Years Ended December 31,		
	2018	2017	2016
REVENUES	$ 349	$ 6,964	$ 5,712
COSTS AND EXPENSES			
Cost of products sold	305	5,806	4,649
Operating expenses	61	763	744
Depreciation, depletion and amortization	—	34	143
Selling, general and administrative	7	168	114
Impairment losses	—	285	447
Total costs and expenses	373	7,056	6,097
OPERATING LOSS	(24)	(92)	(385)
OTHER EXPENSE			
Interest expense, net	2	36	28
Loss on extinguishment of debt	20	—	—
Other, net	61	1	8
LOSS FROM DISCONTINUED OPERATIONS BEFORE INCOME TAX EXPENSE	(107)	(129)	(421)
Income tax expense	158	48	41
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	$ (265)	$ (177)	$ (462)
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES ATTRIBUTABLE TO ET	$ (10)	$ (6)	$ (12)

2017 Transactions

Rover Contribution Agreement

In October 2017, ETO completed the previously announced contribution transaction with a fund managed by Blackstone Energy Partners and Blackstone Capital Partners, pursuant to which ETO exchanged a 49.9% interest in the holding company that owns 65% of the Rover pipeline (“Rover Holdco”). As a result, Rover Holdco is now owned 50.1% by ETO and 49.9% by Blackstone. Upon closing, Blackstone contributed funds to reimburse ETO for its pro rata share of the Rover construction costs incurred by ETO through the closing date, along with the payment of additional amounts subject to certain adjustments.

ETO and Sunoco Logistics Merger

As discussed in Note 1, in April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed the Sunoco Logistics Merger.

Permian Express Partners

In February 2017, the Partnership formed PEP, a strategic joint venture with ExxonMobil. The Partnership contributed its Permian Express 1, Permian Express 2, Permian Longview and Louisiana Access pipelines. ExxonMobil contributed its Longview to Louisiana and Pegasus pipelines, Hawkins gathering system, an idle pipeline in southern Oklahoma, and its Patoka, Illinois terminal. Assets contributed to PEP by ExxonMobil were reflected at fair value on the Partnership’s consolidated balance sheet at the date of the contribution, including $547 million of intangible assets and $435 million of property, plant and equipment.

In July 2017, ETO contributed an approximate 15% ownership interest in Dakota Access and ETCO to PEP, which resulted in an increase in ETO’s ownership interest in PEP to approximately 88%. ETO maintains a controlling financial and voting interest in PEP and is the operator of all of the assets. As such, PEP is reflected as a consolidated subsidiary of the Partnership. ExxonMobil’s interest in PEP is reflected as noncontrolling interest in the consolidated balance sheets. ExxonMobil’s contribution resulted in an increase of $988 million in noncontrolling interest, which is reflected in “Capital contributions from noncontrolling interest” in the consolidated statement of equity.

Bakken Equity Sale

In February 2017, Bakken Holdings Company LLC, an entity in which ETO indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by MPLX LP and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. ETO continues to consolidate Dakota Access and ETCO subsequent to this transaction.

2016 Transactions

PennTex Acquisition

On November 1, 2016, ETO acquired certain interests in PennTex from various parties for total consideration of approximately $627 million in ETO units and cash. Through this transaction, ETO acquired a controlling financial interest in PennTex, whose assets complement ETO’s existing midstream footprint in northern Louisiana. As discussed in Note 8, ETO purchased PennTex’s remaining outstanding common units in June 2017.

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.

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 the Partnership 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 the Partnership’s 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.

Bakken Financing

In August 2016, ETO and Phillips 66 announced the completion of the project-level financing of the Bakken Pipeline. The $2.50 billion credit facility provided substantially all of the remaining capital necessary to complete the projects. As of December 31, 2018, $2.50 billion was outstanding under this credit facility.

Bayou Bridge

In April 2016, Bayou Bridge Pipeline, LLC (“Bayou Bridge”), a joint venture among ETO and Phillips 66, began commercial operations on the 30-inch segment of the pipeline from Nederland, Texas to Lake Charles, Louisiana. The Partnership holds a 60% interest in the entity and is the operator of the system.

Sunoco LP Acquisitions

In August 2016, Sunoco LP acquired the fuels business from Emerge Energy Services LP for $171 million, including tax deductible goodwill of $53 million and intangible assets of $56 million. Additionally, during 2016, Sunoco LP made other acquisitions primarily consisting of convenience stores, totaling $114 million plus the value of inventory on hand at closing and increasing goodwill by $61 million.

In October 2016, Sunoco LP completed the acquisition of a convenience store, wholesale motor fuel distribution, and commercial fuels distribution business for approximately $55 million plus inventory on hand at closing, subject to closing adjustments.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Citrus

ETO 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, an approximately 5,344-mile natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula. Our investment in Citrus is reflected in our interstate transportation and storage segment.

FEP

ETO has 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. ETO’s investment in FEP is reflected in the interstate transportation and storage segment. The Partnership evaluated its investment in FEP for impairment as of December 31, 2017, based on FASB Accounting Standards Codification 323, *Investments - Equity Method and Joint Ventures*. The Partnership recorded an impairment of its investment in FEP of $141 million during the year ended December 31, 2017 due to a negative outlook for long-term transportation contracts as a result of a decrease in production in the Fayetteville basin and a customer re-contracting with a competitor.

MEP

ETO owns 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. ETO’s 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 existing 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

ETO previously owned a 49.99% interest in HPC, which owns RIGS, which delivers natural gas from northwest Louisiana to downstream pipelines and markets through a 450-mile intrastate pipeline system. In April 2018, ETO acquired the remaining 50.01% interest in HPC. Prior to April 2018, HPC was reflected as an unconsolidated affiliate in ETO's financial statements; beginning in April 2018, RIGS is reflected as a wholly-owned subsidiary in ETO's financial statements.

The carrying values of the Partnership's investments in unconsolidated affiliates as of December 31, 2018 and 2017, were as follows:

	December 31,	
	2018	2017
Citrus	$ 1,737	$ 1,754
FEP	107	121
MEP	225	242
HPC	—	28
Others	573	560
Total	$ 2,642	$ 2,705

The following table presents equity in earnings (losses) of unconsolidated affiliates:

	Years Ended December 31,		
	2018	2017	2016
Citrus	$ 141	$ 144	$ 102
FEP	55	53	51
MEP	31	38	40
HPC [(1)]	3	(168)	31
Other	114	77	46
Total equity in earnings of unconsolidated affiliates	$ 344	$ 144	$ 270

[(1)] For the year ended December 31, 2017, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by HPC, which reduced the Partnership's equity in earnings by $185 million.

Summarized Financial Information

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

	December 31,	
	2018 (1)	2017
Current assets	$ 212	$ 206
Property, plant and equipment, net	7,800	8,437
Other assets	39	43
Total assets	$ 8,051	$ 8,686
Current liabilities	$ 1,534	$ 861
Non-current liabilities	3,439	4,492
Equity	3,078	3,333
Total liabilities and equity	$ 8,051	$ 8,686

	Years Ended December 31,		
	2018 (1)	2017	2016
Revenue	$ 1,249	$ 1,358	$ 1,164
Operating income	723	407	714
Net income	460	145	384

(1) Selected balance sheet data as of December 31, 2018 does not include HPC and selected income data for the year ended December 31, 2018 reflects HPC's results for January 1, 2018 through March 31, 2018. HPC was fully consolidated beginning April 1, 2018 as discussed above.

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

5. NET INCOME PER LIMITED PARTNER UNIT:

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding. Diluted net income per limited partner unit is computed by dividing net income (as adjusted as discussed herein), after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding and the assumed conversion of the ET Series A Convertible Preferred Units, as discussed in Note 8. For the diluted earnings per share computation, income allocable to the limited partners is reduced, where applicable, for the decrease in earnings from ET's limited partner unit ownership in ETO or Sunoco LP that would have resulted assuming the incremental units related to our or Sunoco LP's equity incentive plans, as applicable, had been issued during the respective periods. Such units have been determined based on the treasury stock method.

A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Years Ended December 31,		
	2018	2017	2016
Income from continuing operations	$ 3,630	$ 2,543	$ 462
Less: Net income attributable to redeemable noncontrolling interests	39	—	—
Less: Income (loss) from continuing operations attributable to noncontrolling interest	1,888	1,583	(545)
Income from continuing operations, net of noncontrolling interest	1,703	960	1,007
Less: General Partner's interest in income from continuing operations	3	2	3
Less: Convertible Unitholders' interest in net income from continuing operations	33	38	8
Less: Class D Unitholder's interest in income from continuing operations	—	—	—
Income from continuing operations available to Limited Partners	$ 1,667	$ 920	$ 996
Basic Income from Continuing Operations per Limited Partner Unit:			
Weighted average limited partner units	1,423.8	1,078.2	1,045.5
Basic income from continuing operations per Limited Partner unit	$ 1.17	$ 0.86	$ 0.95
Basic income (loss) from discontinued operations per Limited Partner unit	$ (0.01)	$ (0.01)	$ (0.01)
Diluted Income from Continuing Operations per Limited Partner Unit:			
Income from continuing operations available to Limited Partners	$ 1,667	$ 920	$ 996
Dilutive effect of equity-based compensation of subsidiaries, distributions to Convertible Units	33	38	8
Diluted income from continuing operations available to Limited Partners	1,700	958	1,004
Weighted average limited partner units	1,423.8	1,078.2	1,045.5
Dilutive effect of unconverted unit awards and Convertible Units	30.3	72.6	33.1
Dilutive effect of unvested unit awards	7.3	—	—
Weighted average limited partner units, assuming dilutive effect of unvested unit awards	1,461.4	1,150.8	1,078.6
Diluted income from continuing operations per Limited Partner unit	$ 1.16	$ 0.84	$ 0.93
Diluted income (loss) from discontinued operations per Limited Partner unit	$ (0.01)	$ (0.01)	$ (0.01)

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2018	December 31, 2017
Parent Company Indebtedness:		
7.50% Senior Notes due October 15, 2020	$ 1,187	$ 1,187
4.25% Senior Notes due March 15, 2023	1,000	1,000
5.875% Senior Notes due January 15, 2024	1,150	1,150
5.50% Senior Notes due June 1, 2027	1,000	1,000
ET Senior Secured Term Loan	1,220	1,220
ET Senior Secured Revolving Credit Facility	—	1,188
Unamortized premiums, discounts and fair value adjustments, net	(10)	(11)
Deferred debt issuance costs	(27)	(34)
	5,520	6,700
Subsidiary Indebtedness:		
ETO Debt		
2.50% Senior Notes due June 15, 2018	—	650
6.70% Senior Notes due July 1, 2018	—	600
9.70% Senior Notes due March 15, 2019 (1)	400	400
9.00% Senior Notes due April 15, 2019 (1)	450	450
5.50% Senior Notes due February 15, 2020	250	250
5.75% Senior Notes due September 1, 2020	400	400
4.15% Senior Notes due October 1, 2020	1,050	1,050
4.40% Senior Notes due April 1, 2021	600	600
4.65% Senior Notes due June 1, 2021	800	800
5.20% Senior Notes due February 1, 2022	1,000	1,000
4.65% Senior Notes due February 15, 2022	300	300
5.875% Senior Notes due March 1, 2022	900	900
5.00% Senior Notes due October 1, 2022	700	700
3.45% Senior Notes due January 15, 2023	350	350
3.60% Senior Notes due February 1, 2023	800	800
4.20% Senior Notes due September 15, 2023	500	—
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
4.25% Senior Notes due April 1, 2024	500	500
9.00% Debentures due November 1, 2024	65	65
4.05% Senior Notes due March 15, 2025	1,000	1,000
5.95% Senior Notes due December 1, 2025	400	400
4.75% Senior Notes due January 15, 2026	1,000	1,000
3.90% Senior Notes due July 15, 2026	550	550
4.20% Senior Notes due April 15, 2027	600	600
4.00% Senior Notes due October 1, 2027	750	750
4.95% Senior Notes due June 15, 2028	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
5.80% Senior Notes due June 15, 2038	500	—

7.50% Senior Notes due July 1, 2038	550	550
6.85% Senior Notes due February 15, 2040	250	250
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	350
5.15% Senior Notes due February 1, 2043	450	450
5.95% Senior Notes due October 1, 2043	450	450
5.30% Senior Notes due April 1, 2044	700	700
5.15% Senior Notes due March 15, 2045	1,000	1,000
5.35% Senior Notes due May 15, 2045	800	800
6.125% Senior Notes due December 15, 2045	1,000	1,000
5.30% Senior Notes due April 15, 2047	900	900
5.40% Senior Notes due October 1, 2047	1,500	1,500
6.00% Senior Notes due June 15, 2048	1,000	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	546
ETO $5.00 billion Revolving Credit Facility due December 2023	3,694	2,292
ETO $1.00 billion 364-Day Credit Facility due November 2019	—	50
Unamortized premiums, discounts and fair value adjustments, net	17	33
Deferred debt issuance costs	(178)	(170)
	32,288	29,210
Transwestern Debt		
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
Deferred debt issuance costs	(1)	(1)
	574	574
Panhandle Debt		
7.00% Senior Notes due June 15, 2018	—	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	14	28
	399	813
Bakken Project Debt		
Bakken $2.50 billion Credit Facility due August 2019	2,500	2,500
Deferred debt issuance costs	(3)	(8)
	2,497	2,492
Sunoco LP Debt		
4.875% Senior Notes Due January 15, 2023	1,000	—
5.50% Senior Notes Due February 15, 2026	800	—
5.875% Senior Notes Due March 15, 2028	400	—
5.50% Senior Notes due August 1, 2020	—	600

6.375% Senior Notes due April 1, 2023	—	800
6.25% Senior Notes due April 15, 2021	—	800
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	700	—
Sunoco LP $1.50 billion Revolving Credit Facility due September 2019	—	765
Sunoco LP Term Loan due October 1, 2019	—	1,243
Lease-related obligations	107	113
Deferred debt issuance costs	(23)	(34)
	2,984	4,287
USAC Debt		
6.875% Senior Notes due April 1, 2026	725	—
USAC $1.60 billion Revolving Credit Facility due April 2023	1,050	—
Deferred debt issuance costs	(16)	—
	1,759	—
Other	7	8
Total debt	46,028	44,084
Less: Current maturities of long-term debt	2,655	413
Long-term debt, less current maturities	$ 43,373	$ 43,671

(1) As of December 31, 2018, these notes were classified as long-term as management had the intent and ability to refinance the borrowings on a long-term basis. The notes were refinanced in January 2019, as discussed below.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $227 million in unamortized premiums, fair value adjustments and deferred debt issuance costs, net:

2019	$ 3,505
2020	3,068
2021	1,406
2022	5,505
2023	7,255
Thereafter	25,516
Total	$ 46,255

Long-term debt reflected on our consolidated balance sheets includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap.

Notes and Debentures

ET Senior Notes Offering

In October 2017, ET issued $1 billion aggregate principal amount of 4.25% senior notes due 2023. The $990 million net proceeds from the offering were used to repay a portion of the outstanding indebtedness under its term loan facility and for general partnership purposes.

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

ET Senior Notes

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

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

ETO Senior Notes

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

The ETO senior notes are unsecured obligations of the Partnership and as a result, the ETO 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 ETO senior notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

2019 Senior Notes Offering and Redemption

In January 2019, ETO issued the following senior notes:

- $750 million aggregate principal amount of 4.50% senior notes due 2024;
- $1.50 billion aggregate principal amount of 5.25% senior notes due 2029; and
- $1.75 billion aggregate principal amount of 6.25% senior notes due 2049.

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

The senior notes rank equally in right of payment with ETO's existing and future senior debt, and senior in right of payment to any future subordinated debt ETO may incur. The notes of each series will initially be fully and unconditionally guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis so long as it guarantees any of our other long-term debt. The guarantee for each series of notes ranks equally in right of payment with all of the existing and future senior debt of Sunoco Logistics Partners Operations L.P., including its senior notes.

The $3.96 billion net proceeds from the offering were used to make an intercompany loan to ET (which ET used to repay its term loan in full), for general partnership purposes and to redeem at maturity all of the following:

- ETO's $400 million aggregate principal amount of 9.70% senior notes due March 15, 2019;
- ETO's $450 million aggregate principal amount of 9.00% senior notes due April 15, 2019; and
- Panhandle's $150 million aggregate principal amount of 8.125% senior notes due June 1, 2019.

2018 Senior Notes Offering and Redemption

In June 2018, ETO issued the following senior notes:

- $500 million aggregate principal amount of 4.20% senior notes due 2023;
- $1.00 billion aggregate principal amount of 4.95% senior notes due 2028;
- $500 million aggregate principal amount of 5.80% senior notes due 2038; and
- $1.00 billion aggregate principal amount of 6.00% senior notes due 2048.

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

The senior notes rank equally in right of payment with ETO's existing and future senior debt, and senior in right of payment to any future subordinated debt ETO may incur. The notes of each series will initially be fully and unconditionally guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis so long as it guarantees any of our other long-term debt. The guarantee for each series of notes ranks equally in right of payment with all of the existing and future senior debt of Sunoco Logistics Partners Operations L.P., including its senior notes.

The $2.96 billion net proceeds from the offering were used to repay borrowings outstanding under ETO's revolving credit facility, for general partnership purposes and to redeem at maturity all of the following senior notes:

- ETO's $650 million aggregate principal amount of 2.50% senior notes due June 15, 2018;
- Panhandle's $400 million aggregate principal amount of 7.00% senior notes due June 15, 2018; and
- ETO's $600 million aggregate principal amount of 6.70% senior notes due July 1, 2018.

The aggregate amount paid to redeem these notes was approximately $1.65 billion.

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 5.559% at December 31, 2018.

As part of ETO's senior notes offering in June 2018 discussed above, Panhandle's $400 million aggregate principal amount of 7.00% senior notes due June 15, 2018 were redeemed.

Sunoco LP Senior Notes Offering

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028. Sunoco LP used the proceeds from the private offering, along with proceeds from its retail divestment to:

- redeem in full its existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020 and $800 million in aggregate principal amount of 6.375% senior notes due 2023;
- repay in full and terminate its term loan;
- pay all closing costs in connection with its retail divestment;
- redeem the outstanding Sunoco LP Series A Preferred Units; and
- repurchase 17,286,859 Sunoco LP common units owned by ETO.

On December 3, 2018, Sunoco LP completed an exchange of the notes for registered notes with substantially identical terms.

USAC Senior Notes

In March 2018, USAC completed a private offering of $725 million aggregate principal amount of senior notes that mature on April 1, 2026. The notes accrue interest from March 23, 2018 at the rate of 6.875% per year. Interest on the notes will be payable semi-annually in arrears on each April 1 and October 1, commencing on October 1, 2018. On January 14, 2019, USAC completed an exchange of these notes for registered notes with substantially identical terms.

In February 2019, USAC announced the offering of $750 million aggregate principal amount of senior unsecured notes due 2027 in a private placement to eligible purchasers. USAC intends to use the net proceeds from this offering to repay a portion of its existing borrowings under the USAC credit facility and for general partnership purposes.

Term Loans, Credit Facilities and Commercial Paper

ET Term Loan Facility

On February 2, 2017, the Partnership entered into a Senior Secured Term Loan Agreement (the "Term Credit Agreement") with Credit Suisse AG, Cayman Islands Branch, as administrative agent, and the other lenders party thereto. The Term Credit Agreement had a scheduled maturity date of February 2, 2024, with an option for the Parent Company to extend the term subject to the terms and conditions set forth therein. The Term Credit Agreement contained an accordion feature, under which the total commitments may be increased, subject to the terms thereof. In connection with the Parent Company's entry into the Senior Secured Term Loan Agreement on February 2, 2017, the Parent Company terminated its previous term loan agreements.

Pursuant to the Term Credit Agreement, the Term Lenders provided senior secured financing in an aggregate principal amount of $2.2 billion (the "Term Loan Facility"). Under the Term Credit Agreement, the obligations of the Parent Company were secured by a lien on substantially all of the Parent Company's and certain of its subsidiaries' tangible and intangible assets.

Interest accrued on advances at a LIBOR rate or a base rate, based on the election of the Parent Company for each interest period, plus an applicable margin.

On January 15, 2019, Energy Transfer LP paid in full all outstanding borrowings under its Senior Secured Term Loan Agreement and thereafter terminated the term loan agreement. In connection with the termination of the term loan agreement, the collateral securing certain series of the Partnership's outstanding senior notes was released in accordance with the terms of the applicable indentures governing such senior notes.

ET Revolving Credit Facility

On March 24, 2017, the Parent Company previously had a Credit Agreement (the "Revolver Credit Agreement") with Credit Suisse AG, Cayman Islands Branch as administrative agent and the other lenders party thereto (the "Revolver Lenders"). The Revolver Credit Agreement had a scheduled maturity date of March 24, 2022 and included an option for the Parent Company to extend the term, in each case subject to the terms and conditions set forth therein. Pursuant to the Revolver Credit Agreement, the lenders committed to provide advances up to an aggregate principal amount of $1.50 billion at any one time outstanding, and the Parent Company had the option to request increases in the aggregate commitments by up to $500 million in additional commitments. Under the Revolver Credit Agreement, the obligations of the Partnership were secured by a lien on substantially all of the Partnership's and certain of its subsidiaries' tangible and intangible assets.

In connection with the closing of the Energy Transfer Merger in October 2018, the Partnership repaid in full all outstanding borrowings under the facility and the facility was terminated.

ETO Five-Year Credit Facility

ETO's revolving credit facility (the "ETO Five-Year Credit Facility") previously allowed for unsecured borrowings up to $4.00 billion and matured in December 2022. On October 19, 2018, the ETO Five-Year Credit Facility was amended to increase the borrowing capacity by $1.00 billion, to $5.00 billion, and to extend the maturity date to December 1, 2023. The ETO Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $6.00 billion under certain conditions.

As of December 31, 2018, the ETO Five-Year Credit Facility had $3.69 billion outstanding, of which $2.34 billion was commercial paper. The amount available for future borrowings was $1.24 billion after taking into account letters of credit of $63 million. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 3.57%.

ETO 364-Day Facility

ETO's 364-day revolving credit facility (the "ETO 364-Day Facility") previously allowed for unsecured borrowings up to $1.00 billion and matured on November 30, 2018. On October 19, 2018, the ETO 364-Day Facility was amended to extend the maturity date to November 29, 2019. As of December 31, 2018, the ETO 364-Day Facility had no outstanding borrowings.

Bakken Credit Facility

In August 2016, ETO and Phillips 66 completed project-level financing of the Bakken pipeline. The $2.50 billion credit facility matures in August 2019 (the "Bakken Credit Facility"). As of December 31, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings, all of which has been reflected in current maturities of long-term debt on the Partnership's consolidated balance sheets. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.27%.

Sunoco LP Term Loan

Sunoco LP has a term loan agreement which provides secured financing in an aggregate principal amount of up to $2.035 billion due 2019. In January 2017, Sunoco LP entered into a limited waiver to its term loan, under which the agents and lenders party thereto waived and deemed remedied the miscalculations of Sunoco LP's leverage ratio as set forth in its previously delivered compliance certificates and the resulting failure to pay incremental interest owed under the term loan.

The Sunoco LP term loan was repaid in full and terminated on January 23, 2018. See "Sunoco LP Senior Notes Offering" above.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.50 billion revolving credit agreement (the "Sunoco LP Credit Facility"). In July 2018, Sunoco LP amended its revolving credit agreement, including extending the expiration to July 2023 (which may be extended in accordance with the terms of the credit agreement). Borrowings under the amended revolving credit agreement were used to pay off Sunoco LP's existing revolving credit facility which was entered into in September 2014.

As of December 31, 2018, the Sunoco LP Credit Facility had $700 million outstanding borrowings and $8 million in standby letters of credit. The unused availability on the revolver at December 31, 2018 was $792 million. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.45%.

USAC Credit Facility

USAC currently has a $1.60 billion revolving credit facility, which matures on April 2, 2023 and permits up to $400 million of future increases in borrowing capacity.

As of December 31, 2018, USAC had $1.05 billion of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2018, USAC had $550 million of availability under its credit facility. The weighted average interest rate on the total amount outstanding as of December 31, 2018 was 4.69%.

Covenants Related to Our Credit Agreements

Covenants Related to the Parent Company

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

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

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

Covenants Related to ETO

The agreements relating to the ETO 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 ETO Credit Facilities 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 ETO Credit Facilities) during certain Defaults (as defined in the ETO Credit Facilities) and during any Event of Default (as defined in the ETO Credit Facilities);
- 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 ETO Credit Facilities applicable margin and rate used in connection with the interest rates and commitment fees, respectively, are based on the credit ratings assigned to our senior, unsecured, non-credit enhanced long-term debt. The applicable margin for eurodollar rate loans under the ETO Five-Year Facility ranges from 1.125% to 2.000% and the applicable margin for base rate loans ranges from 0.125% to 1.000%. The applicable rate for commitment fees under the ETO Five-Year Facility ranges from 0.125% to 0.300%. The applicable margin for eurodollar rate loans under the ETO 364-Day Facility ranges from 1.125% to 1.750% and the applicable margin for base rate loans ranges from 0.250% to 0.750%. The applicable rate for commitment fees under the ETO 364-Day Facility ranges from 0.125% to 0.225%.

The ETO Credit Facilities contain various covenants including limitations on the creation of indebtedness and liens, and related to the operation and conduct of our business. The ETO Credit Facilities also limit us, on a rolling four quarter basis, to a maximum Consolidated Funded Indebtedness to Consolidated EBITDA ratio, as defined in the underlying credit agreements, of 5.0 to 1, which can generally be increased to 5.5 to 1 during a Specified Acquisition Period. Our Leverage Ratio was 3.38 to 1 at December 31, 2018, as calculated in accordance with the credit agreements.

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 Partnership's or our subsidiaries' ability to incur additional debt and/or our ability to pay distributions to Unitholders.

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 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 Sunoco LP

The Sunoco LP Credit Facility contains various customary representations, warranties, covenants and events of default, including a change of control event of default, as defined therein. Sunoco LP's Credit Facility requires Sunoco LP to maintain a Net Leverage Ratio of not more than 5.5 to 1. The maximum Net Leverage Ratio is subject to upwards adjustment of not more than 6.0 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in certain specified acquisitions of not less than $50 million (as permitted under Sunoco LP's Credit Facility agreement). The Sunoco LP Credit Facility also requires Sunoco LP to maintain an Interest Coverage Ratio (as defined in the Sunoco LP's Credit Facility agreement) of not less than 2.25 to 1.

Covenants Related to USAC

The USAC Credit Facility contains covenants that limit (subject to certain exceptions) USAC's ability to, among other things:

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- merge or consolidate;
- sell our assets; or
- make certain acquisitions.

The credit facility is also subject to the following financial covenants, including covenants requiring us to maintain:

- a minimum EBITDA to interest coverage ratio of 2.5 to 1.0, determined as of the last day of each fiscal quarter; and
- a maximum funded debt to EBITDA ratio, determined as of the last day of each fiscal quarter, for the annualized trailing three months of (i) 5.75 to 1 through the end of the fiscal quarter ending March 31, 2019, (ii) 5.5 to 1 through the end of the fiscal quarter ending December 31, 2019 and (iii) 5.0 to 1 thereafter, in each case subject to a provision for increases to such thresholds by 0.50 in connection with certain future acquisitions for the six consecutive month period following the period in which any such acquisition occurs.

Compliance With Our Covenants

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

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2018.

7. REDEEMABLE NONCONTROLLING INTERESTS

Certain redeemable noncontrolling interest in the Partnership's subsidiaries are reflected as mezzanine equity on the consolidated balance sheet. Redeemable noncontrolling interests as of December 31, 2018 include (i) a balance of $477 million related to the USAC Preferred Units described below and (ii) a balance of $22 million related to noncontrolling interest holders in one of the Partnership's consolidated subsidiaries that have the option to sell their interests to the Partnership.

USAC Series A Preferred Units

On April 2, 2018, USAC issued 500,000 USAC Preferred Units at a price of $1,000 per USAC Preferred Unit, for total gross proceeds of $500 million in a private placement.

The USAC Preferred Units are entitled to receive cumulative quarterly distributions equal to $24.375 per USAC Preferred Unit, subject to increase in certain limited circumstances. The USAC Preferred Units will have a perpetual term, unless converted or redeemed. Certain portions of the USAC Preferred Units will be convertible into USAC common units at the election of the holders beginning in 2021. To the extent the holders of the USAC Preferred Units have not elected to convert their preferred units by the fifth anniversary of the issue date, USAC will have the option to redeem all or any portion of the USAC Preferred Units for cash. In addition, at any time on or after the tenth anniversary of the issue date, the holders of the USAC Preferred Units will have the right to require USAC to redeem all or any portion of the USAC Preferred Units, and the Partnership may elect to pay up to 50% of such redemption amount in USAC common units.

8. EQUITY:

Limited Partner Units

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

As of December 31, 2018, there were issued and outstanding 2.62 billion Common Units representing an aggregate 99.9% limited partner interest in the Partnership.

Our Partnership Agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. For any fiscal year that the Partnership has net profits, such net profits are first allocated to the General Partner until the aggregate amount of net profits for the current and all prior fiscal years equals the aggregate amount of net losses allocated to the General Partner for the current and all prior fiscal years. Second, such net profits shall be allocated to the Limited Partners pro rata in accordance with their respective sharing ratios. For any fiscal year in which the Partnership has net losses, such net losses shall be first allocated to the Limited Partners in proportion to their respective adjusted capital account balances, as defined by the Partnership Agreement, (before taking into account such net losses) until their adjusted capital account balances have been reduced to zero. Second, all remaining net losses shall be allocated to the General Partner. The General Partner may distribute to the Limited Partners funds of the Partnership that the General Partner reasonably determines are not needed for the payment of existing or foreseeable Partnership obligations and expenditures.

Common Units

The change in ET Common Units during the years ended December 31, 2018, 2017 and 2016 was as follows:

	Years Ended December 31,		
	2018	2017	2016
Number of Common Units, beginning of period	1,079.1	1,046.9	1,044.8
Conversion of ET Series A Convertible Preferred Units to common units	79.1	—	—
Common Unit increase from Energy Transfer Merger	1,458.9	—	—
Issuance of common units	2.3	32.2	2.1
Number of Common Units, end of period	2,619.4	1,079.1	1,046.9

In October 2018, ET issued 1.46 billion ET Common Units in connection with the Energy Transfer Merger.

ET Equity Distribution Agreement

In March 2017, the Partnership entered into an equity distribution agreement with an aggregate offering price up to $1 billion. There was no activity under the distribution agreements for the year ended December 31, 2018.

ET Series A Convertible Preferred Units

In May 2018, the Partnership converted its 329.3 million Series A Convertible Preferred Units into approximately 79.1 million ET common units in accordance with the terms of ET's partnership agreement.

ET Class A Units

In connection with the Energy Transfer Merger, the Partnership issued 647,745,099 Class A units ("ET Class A Units") representing limited partner interests in the Partnership to LE GP, LLC ("LE GP"), the general partner of ET. The number of ET Class A Units issued allows LE GP and its affiliates to retain a voting interest in the Partnership that is identical to their voting interest in the Partnership prior to the completion of the Merger. The ET Class A Units are entitled to vote together with the Partnership's common units, as a single class, except as required by law. Additionally, ET's partnership agreement provides that, under certain circumstances, upon the issuance by the Partnership of additional common units or any securities that have voting rights that are pari passu with the Partnership common units, the Partnership will issue to any holder of ET Class A Units additional ET Class A Units such that the holder maintains a voting interest in the Partnership that is identical to its voting interest in the Partnership prior to such issuance. The ET Class A Units are not entitled to distributions and otherwise have no economic attributes.

Repurchase Program

In February 2015, the Partnership announced a common unit repurchase program, whereby the Partnership may repurchase up to an additional $2 billion of ET Common Units in the open market at the Partnership's discretion, subject to market conditions and other factors, and in accordance with applicable regulatory requirements. The Partnership repurchased no ET Common Units under this program in 2018, 2017 or 2016 and there was $936 million available to use under the program as of December 31, 2018.

Class D Units

In 2013, the Partnership issued 3,080,000 Class D Units of ET pursuant to an agreement with a former executive. The Class D Units were convertible to ET Common Units, subject to certain vesting requirements which were not met prior to the former executive's termination in 2016.

Sale of Common Units by Subsidiaries

The Parent Company accounts for the difference between the carrying amount of its investment in subsidiaries and the underlying book value arising from issuance of units by subsidiaries (excluding unit issuances to the Parent Company) as a capital transaction. If a subsidiary issues units at a price less than the Parent Company's carrying value per unit, the Parent Company assesses whether the investment has been impaired, in which case a provision would be reflected in our statement of operations. The Parent Company did not recognize any impairment related to the issuances of subsidiary common units during the periods presented.

ETO Class E Units

There were previously 8.9 million Class E Units outstanding, all of which were owned by HHI. The Class E Units were entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. As the Class E Units were owned by a wholly-owned subsidiary, the cash distributions on those units were eliminated in our consolidated financial statements. On December 31, 2018, the Class E units were converted to Class L units, as described below.

ETO Class G Units

There were previously 90.7 million Class G Units outstanding, all of which were held by a wholly-owned subsidiary of the Partnership. The Class G 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 G Unit per year. Allocations of depreciation and amortization to the Class G Units for tax purposes were based on a predetermined percentage and are not contingent on whether ETO has net income or loss. These units were reflected as treasury units in the consolidated financial statements. On December 31, 2018, the Class G units were converted to Class L units, as described below.

ETO Class H Units

The ETO Class H Units were generally entitled to (i) allocations of profits, losses and other items from ETO corresponding to 90.05% of the profits, losses, and other items allocated to ETO 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 ETO for each quarter equal to 90.05% of the cash distributed to ETO 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 ETO and Sunoco Logistics in April 2017.

ETO Class I Units

In connection with the Bakken Pipeline Transaction discussed in Note 3, in March 2015, ETO issued 100 ETO Class I Units. The ETO 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 ETO 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 ETO Class I Units and (ii) after making cash distributions to ETO 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 ETO's Partnership Agreement, as amended, (the "Partnership Agreement") for such quarter over the cumulative amount of available cash previously distributed commencing with the quarter ended March 31, 2015 until the quarter ending December 31, 2016. The Class I Units were cancelled in connection with the Energy Transfer Merger in October 2018.

Bakken Equity Sale

In February 2017, Bakken Holdings Company LLC, an entity in which ETO indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by MPLX LP and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. ETO continues to consolidate Dakota Access and ETCO subsequent to this transaction.

ETO Class K Units

On December 29, 2016, ETO issued to certain of its indirect subsidiaries, in exchange for cash contributions and the exchange of outstanding common units representing limited partner interests in ETO, Class K Units, each of which is entitled to a quarterly cash distribution of $0.67275 per Class K Unit prior to ETO making distributions of available cash to any class of units, excluding any cash available distributions or dividends or capital stock sales proceeds received by ETO from ETO Holdco. If ETO is unable to pay the Class K Unit quarterly distribution with respect to any quarter, the accrued and unpaid distributions will accumulate until paid and any accumulated balance will accrue 1.5% per annum until paid. As of December 31, 2018, a total of 101.5 million Class K Units were held by wholly-owned subsidiaries of ETO.

ETO Class L Units

On December 31, 2018, ETO issued a new class of limited partner interests titled Class L Units to two wholly-owned subsidiaries of the Partnership when the Partnership's outstanding Class E units and Class G units held by such subsidiaries were converted into Class L Units. As a result of the conversion, the Class E units and Class G units were cancelled.

The Class L Units generally do not have any voting rights. The Class L Units are entitled to aggregate cash distributions equal to 7.65% per annum of the total amount of cash generated by us and our subsidiaries, other than ETP Holdco, and available for distribution. Distributions shall be paid quarterly, in arrears, within 45 days after the end of each quarter. As the Class L Units are owned by a wholly-owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements.

Sales of Common Units by Sunoco Logistics

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

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.

ETO Preferred Units

In November 2017, ETO issued 950,000 of its 6.250% Series A Preferred Units at a price of $1,000 per unit and 550,000 of its 6.625% Series B Preferred Units at a price of $1,000 per unit. In April 2018, ETO issued 18 million of its 7.375% Series C Preferred Units at a price of $25 per unit. In July 2018, ETO issued 17.8 million of its 7.625% Series D Preferred Units at a price of $25 per unit. Subsequent to the Energy Transfer Merger, all of ETO's Series A, Series B, Series C and Series D Preferred Units remain outstanding.

ETO Series A Preferred Units

Distributions on the Series A Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2023, at a rate of 6.250% per annum of the stated liquidation preference of $1,000. On and after February 15, 2023, distributions on the Series A Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.028% per annum. The Series A Preferred Units are redeemable at ETO's option on or after February 15, 2023 at a redemption price of $1,000 per Series A Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series B Preferred Units

Distributions on the Series B Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2028, at a rate of 6.625% per annum of the stated liquidation preference of $1,000. On and after February 15, 2028, distributions on the Series B Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.155% per annum. The Series B Preferred Units are redeemable at ETO's option on or after February 15, 2028 at a redemption price of $1,000 per Series B Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series C Preferred Units

Distributions on the Series C Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2023, at a rate of 7.375% per annum of the stated liquidation preference of $25. On and after May 15, 2023, distributions on the Series C Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.530% per annum. The Series C Preferred Units are redeemable at ETO's option on or after May 15, 2023 at a redemption price of $25 per Series C Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series D Preferred Units

Distributions on the Series D Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, August 15, 2023, at a rate of 7.625% per annum of the stated liquidation preference of $25. On and after August 15, 2023, distributions on the Series D Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.738% per annum. The Series D Preferred Units are redeemable at ETO's option on or after August 15, 2023 at a redemption price of $25 per Series D Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

PennTex Tender Offer and Limited Call Right Exercise

In June 2017, ETO purchased all of the outstanding PennTex common units not previously owned by ETO for $20.00 per common unit in cash. ETO now owns all of the economic interests of PennTex, and PennTex common units are no longer publicly traded or listed on the NASDAQ.

Subsidiary Equity Transactions

Sunoco LP's Common Unit Repurchase

In February 2018, after the record date for Sunoco LP's fourth quarter 2017 cash distributions, Sunoco LP repurchased 17,286,859 Sunoco LP common units owned by ETO for aggregate cash consideration of approximately $540 million. ETO used the proceeds from the sale of the Sunoco LP common units to repay amounts outstanding under its revolving credit facility.

Sunoco LP's Equity Distribution Program

In October 2016, Sunoco LP entered into an equity distribution agreement pursuant to which Sunoco LP may sell from time to time common units having aggregate offering prices of up to $400 million.

For the year ended December 31, 2018, Sunoco LP issued no additional units under its ATM program. For the years ended December 31, 2017 and 2016, Sunoco LP issued an additional 1.3 million and 2.8 million units with total net proceeds of $33 million and $71 million, net of commissions of $0.3 million and $1 million, respectively. As of December 31, 2018, $295 million of Sunoco LP common units remained available to be issued under the currently effective equity distribution agreement.

Sunoco LP's Unit Issuances

On March 31, 2016, Sunoco LP sold 2.3 million of Sunoco LP's common units in a private placement to the Partnership.

In January 2016, Sunoco LP issued 16.4 million Class C units representing limited partner interest consisting of (i) 5.2 million Class C Units issued by Sunoco LP to Aloha as consideration for the contribution by Aloha to an indirect wholly-owned subsidiary, and (ii) 11.2 million Class C Units that were issued by Sunoco LP to its indirect wholly-owned subsidiaries in exchange for all of the outstanding Class A Units held by such subsidiaries.

Sunoco LP's Series A Preferred Units

On March 30, 2017, ET purchased 12.0 million Sunoco LP Series A Preferred Units representing limited partner interests in Sunoco LP in a private placement transaction for an aggregate purchase price of $300 million. The distribution rate of Sunoco LP Series A Preferred Units is 10.00%, per annum, of the $25.00 liquidation preference per unit until March 30, 2022, at which point the distribution rate will become a floating rate of 8.00% plus three-month LIBOR of the liquidation preference.

In January 2018, Sunoco LP redeemed all outstanding Sunoco LP Series A Preferred Units held by ET for an aggregate redemption amount of approximately $313 million. The redemption amount included the original consideration of $300 million and a 1% call premium plus accrued and unpaid quarterly distributions.

USAC's Distribution Reinvestment Program

During the nine months ended December 31, 2018, distributions of $1 million were reinvested under the USAC distribution reinvestment program resulting in the issuance of approximately 39,280 USAC common units.

USAC's Warrant Private Placement

On April 2, 2018, USAC issued two tranches of warrants to purchase USAC common units (the "USAC Warrants"), which included USAC Warrants to purchase 5,000,000 common units with a strike price of $17.03 per unit and USAC Warrants to purchase 10,000,000 common units with a strike price of $19.59 per unit. The USAC Warrants may be exercised by the holders thereof at any time beginning on the one year anniversary of the closing date and before the tenth anniversary of the closing date. Upon exercise of the USAC Warrants, USAC may, at its option, elect to settle the USAC Warrants in common units on a net basis.

USAC's Class B Units

The USAC Class B Units, all of which are owned by ETO, are a new class of partnership interests of USAC that have substantially all of the rights and obligations of a USAC common unit, except the USAC Class B Units will not participate in distributions for the first four quarters following the closing date of the USAC Transaction on April 2, 2018. Each USAC Class B Unit will automatically convert into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019.

Parent Company Quarterly Distributions of Available Cash

Our distribution policy is consistent with the terms of our Partnership Agreement, which requires that we distribute all of our available cash quarterly. The Parent Company's only cash-generating assets currently consist of distributions from its interest in ETO.

Our distributions declared and paid with respect to our common units for the periods presented were as follows:

Quarter Ended	Record Date	Payment Date		Rate
December 31, 2015	February 4, 2016	February 19, 2016	$	0.2850
March 31, 2016 [(1)]	May 6, 2016	May 19, 2016		0.2850
June 30, 2016 [(1)]	August 8, 2016	August 19, 2016		0.2850
September 30, 2016 [(1)]	November 7, 2016	November 18, 2016		0.2850
December 31, 2016 [(1)]	February 7, 2017	February 21, 2017		0.2850
March 31, 2017 [(1)]	May 10, 2017	May 19, 2017		0.2850
June 30, 2017 [(1)]	August 7, 2017	August 21, 2017		0.2850
September 30, 2017 [(1)]	November 7, 2017	November 20, 2017		0.2950
December 31, 2017 [(1)]	February 8, 2018	February 20, 2018		0.3050
March 31, 2018	May 7, 2018	May 21, 2018		0.3050
June 30, 2018	August 6, 2018	August 20, 2018		0.3050
September 30, 2018	November 8, 2018	November 19, 2018		0.3050
December 31, 2018	February 8, 2019	February 19, 2019		0.3050

(1) Certain common unitholders elected to participate in a plan pursuant to which those unitholders elected to forego their cash distributions on all or a portion of their common units for a period of up to nine quarters commencing with the distribution for the quarter ended March 31, 2016 and, in lieu of receiving cash distributions on these common units for each such quarter, each said unitholder received Convertible Units (on a one-for-one basis for each common unit as to which the participating unitholder elected be subject to this plan) that entitled them to receive a cash distribution of up to $0.11 per Convertible Unit. See additional information below.

Our distributions declared and paid with respect to our Convertible Unit during the years ended December 31, 2016 and 2017 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2016	May 6, 2016	May 19, 2016	$ 0.1100
June 30, 2016	August 8, 2016	August 19, 2016	0.1100
September 30, 2016	November 7, 2016	November 18, 2016	0.1100
December 31, 2016	February 7, 2017	February 21, 2017	0.1100
March 31, 2017	May 10, 2017	May 19, 2017	0.1100
June 30, 2017	August 7, 2017	August 21, 2017	0.1100
September 30, 2017	November 7, 2017	November 20, 2017	0.1100
December 31, 2017	February 8, 2018	February 20, 2018	0.1100
March 31, 2018	May 7, 2018	May 21, 2018	0.1100

ETO Preferred Unit Distributions

Distributions on the Partnership's Series A, Series B, Series C and Series D preferred units declared and/or paid by the Partnership during the periods presented were as follows:

Period Ended	Record Date	Payment Date	Series A (1)	Series B (1)	Series C	Series D
December 31, 2017	February 1, 2018	February 15, 2018	$ 15.4510 *	$ 16.3780 *	$ —	$ —
June 30, 2018	August 1, 2018	August 15, 2018	31.2500	33.1250	0.5634 *	—
September 30, 2018	November 1, 2018	November 15, 2018	—	—	0.4609	0.5931 *
December 31, 2018	February 1, 2019	February 15, 2019	31.2500	33.1250	0.4609	0.4766

* Represent prorated initial distributions.

(1) Series A and Series B preferred unit distributions are paid on a bi-annual basis.

Sunoco LP Cash Distributions

The following table illustrates the percentage allocations of available cash from operating surplus between Sunoco LP's common unitholders and the holder of its IDRs based on the specified target distribution levels, after the payment of distributions to Class C unitholders. The amounts set forth under "marginal percentage interest in distributions" are the percentage interests of the IDR holder and the common unitholders in any available cash from operating surplus which Sunoco LP distributes up to and including the corresponding amount in the column "total quarterly distribution per unit target amount." The percentage interests shown for common unitholders and IDR holder for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Common Unitholders	Holder of IDRs
Minimum Quarterly Distribution	$0.4375	100%	—%
First Target Distribution	$0.4375 to $0.503125	100%	—%
Second Target Distribution	$0.503125 to $0.546875	85%	15%
Third Target Distribution	$0.546875 to $0.656250	75%	25%
Thereafter	Above $0.656250	50%	50%

Distributions on Sunoco LP's units declared and/or paid by Sunoco LP were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 5, 2016	February 16, 2016	$ 0.8013
March 31, 2016	May 6, 2016	May 16, 2016	0.8173
June 30, 2016	August 5, 2016	August 15, 2016	0.8255
September 30, 2016	November 7, 2016	November 15, 2016	0.8255
December 31, 2016	February 13, 2017	February 21, 2017	0.8255
March 31, 2017	May 9, 2017	May 16, 2017	0.8255
June 30, 2017	August 7, 2017	August 15, 2017	0.8255
September 30, 2017	November 7, 2017	November 14, 2017	0.8255
December 31, 2017	February 6, 2018	February 14, 2018	0.8255
March 31, 2018	May 7, 2018	May 15, 2018	0.8255
June 30, 2018	August 7, 2018	August 15, 2018	0.8255
September 30, 2018	November 6, 2018	November 14, 2018	0.8255
December 31, 2018	February 6, 2019	February 14, 2019	0.8255

USAC Cash Distributions

Subsequent to the Energy Transfer Merger and USAC Transactions described in Note 1 and Note 3, respectively, ETO owns approximately 39.7 million USAC common units and 6.4 million USAC Class B units. As of December 31, 2018, USAC had approximately 96.4 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding incentive distribution rights.

Distributions on USAC's units declared and/or paid by USAC subsequent to the USAC transaction on April 2, 2018 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2018	May 1, 2018	May 11, 2018	$ 0.5250
June 30, 2018	July 30, 2018	August 10, 2018	0.5250
September 30, 2018	October 29, 2018	November 09, 2018	0.5250
December 31, 2018	January 28, 2019	February 8, 2019	0.5250

Accumulated Other Comprehensive Income (Loss)

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

	December 31,	
	2018	2017
Available-for-sale securities [(1)]	$ 2	$ 8
Foreign currency translation adjustment	(5)	(5)
Actuarial gain (loss) related to pensions and other postretirement benefits	(48)	(5)
Investments in unconsolidated affiliates, net	9	5
Total AOCI, net of tax	(42)	3
Amounts attributable to noncontrolling interest	—	(3)
Total AOCI included in partners' capital, net of tax	$ (42)	$ —

(1) Effective January 1, 2018, the Partnership adopted Accounting Standards Update No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*, which resulted in the reclassification of $2 million from accumulated other comprehensive income related to available-for-sale equity securities to common unitholders.

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

	December 31,	
	2018	2017
Available-for-sale securities	$ (1)	$ (2)
Foreign currency translation adjustment	2	3
Actuarial loss relating to pension and other postretirement benefits	12	3
Total	$ 13	$ 4

9. NON-CASH COMPENSATION PLANS:

ET Non-Cash Compensation Plan

We, Sunoco LP and USAC, have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase Common Units, restricted units, phantom units, distribution equivalent rights ("DERs"), common unit appreciation rights, cash restricted units and other non-cash compensation awards. As of December 31, 2018, an aggregate total of 15.1 million ET Common Units remain available to be awarded under our equity incentive plans.

ET Long-Term Incentive Plan

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, ET 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, 2017 [1]	19.5	$ 18.03
Awards granted	7.8	13.00
Awards vested	(3.5)	21.35
Awards forfeited	(1.4)	15.16
Unvested awards as of December 31, 2018	22.4	15.94

(1) In connection with the Energy Transfer Merger, ET assumed the former ETO plans, including the related unvested awards. Outstanding awards under the former ETO plans are reflected for the entire period above. Amounts related to the period prior to the Energy Transfer Merger are adjusted for the 1.28 to 1 conversion ratio that was applied in the merger.

During the years ended December 31, 2018, 2017, and 2016, the weighted average grant-date fair value per unit award granted was $13.00, $17.01 and $16.37, respectively. The total fair value of awards vested was $49 million, $40 million, and $40 million, respectively, based on the market price of the respective Common Units as of the vesting date. As of December 31, 2018, a total of 22 million unit awards remain unvested, for which ET expects to recognize a total of $228 million in compensation expense over a weighted average period of 2.7 years.

Cash Restricted Units. We previously granted cash restricted units, which entitled the award recipient to receive cash equal to the market value of one ET Common Unit upon vesting. The Partnership does not currently have any cash restricted units outstanding.

Subsidiary Non-Cash Compensation Plans

Each of Sunoco LP and USAC has granted restricted or phantom unit awards (collectively, the "Subsidiary Unit Awards") to employees and directors that entitle the grantees to receive common units of the respective subsidiary. In some cases, at the discretion of the respective subsidiary's compensation committee, the grantee may instead receive an amount of cash equivalent to the value of common units upon vesting. Substantially all of the Subsidiary Unit Awards are time-vested grants, which generally vest over a three or five-year period, that entitles the grantees of the unit awards to receive an amount of cash equal to the per unit cash distributions made by the respective subsidiaries during the period the restricted unit is outstanding.

The following table summarizes the activity of the Subsidiary Unit Awards:

	Sunoco LP		USAC	
	Number of Units	Weighted Average Grant-Date Fair Value Per Unit	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2017	1.7	$ 31.89	1.0	$ 14.24
Awards granted	1.1	27.67	1.1	15.47
Awards vested	(0.4)	32.92	(0.6)	14.79
Awards forfeited	(0.3)	31.26	(0.1)	17.85
Unvested awards as of December 31, 2018	2.1	29.15	1.4	14.98

The following table summarizes the weighted average grant-date fair value per unit award granted:

	Years Ended December 31,		
	2018	2017	2016
Sunoco LP	$ 27.67	$ 28.31	$ 26.95
USAC	15.47	N/A	N/A

The total fair value of Subsidiary Unit Awards vested for the years ended December 31, 2018, 2017 and 2016 was $22 million, $9 million, and $0.1 million, respectively, based on the market price of Sunoco LP and USAC common units as of the vesting date for the years ended December 31, 2018 and Sunoco LP for the years ended December 31, 2017 and 2016. As of December 31, 2018, estimated compensation cost related to Subsidiary Unit Awards not yet recognized was $45 million, and the weighted average period over which this cost is expected to be recognized in expense is 3.3 years.

10. INCOME TAXES:

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

	Years Ended December 31,		
	2018	2017	2016
Current expense (benefit):			
Federal	$ (8)	$ 54	$ (47)
State	19	(16)	(34)
Total	11	38	(81)
Deferred expense (benefit):			
Federal	181	(2,055)	(189)
State	(188)	184	12
Total	(7)	(1,871)	(177)
Total income tax expense (benefit) from continuing operations	$ 4	$ (1,833)	$ (258)

Historically, our effective tax rate has differed from the statutory rate primarily due to partnership earnings that are not subject to United States federal and most state income taxes at the partnership level. A reconciliation of income tax expense at the United States statutory rate to the income tax benefit attributable to continuing operations for the years ended December 31, 2018, 2017 and 2016 is as follows:

	Years Ended December 31,		
	2018	2017	2016
Income tax expense at United States statutory rate	$ 763	$ 248	$ 71
Increase (reduction) in income taxes resulting from:			
Partnership earnings not subject to tax	(635)	(477)	(576)
Goodwill impairment	—	207	278
State tax, net of federal tax benefit	(125)	124	(10)
Dividend received deduction	(5)	(14)	(15)
Federal rate change	—	(1,812)	—
Change in tax status of subsidiary	—	(124)	—
Other	6	15	(6)
Income tax expense (benefit) from continuing operations	$ 4	$ (1,833)	$ (258)

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,	
	2018	2017
Deferred income tax assets:		
Net operating losses, alternative minimum tax credit and other carryforwards	$ 768	$ 683
Pension and other postretirement benefits	34	21
Long-term debt	13	14
Other	181	191
Total deferred income tax assets	996	909
Valuation allowance	(96)	(189)
Net deferred income tax assets	900	720
Deferred income tax liabilities:		
Property, plant and equipment	(782)	(1,036)
Investments in unconsolidated affiliates	(2,872)	(2,726)
Trademarks	(63)	(173)
Other	(109)	(100)
Total deferred income tax liabilities	(3,826)	(4,035)
Net deferred income taxes	$ (2,926)	$ (3,315)

As of December 31, 2018, ETP Holdco had a federal net operating loss carryforward of $2.60 billion, of which $1.80 billion will expire in 2031 through 2037 while the remaining can be carried forward indefinitely. As of December 31, 2017, Sunoco Property Company LLC, a corporate subsidiary of Sunoco LP, had a federal net operating loss carryforward of $364 million. The entire net operating loss carryforward will be fully utilized to offset the taxable gain associated with the retail divestment in 2018.

Our corporate subsidiaries have $31 million of federal alternative minimum tax credits at December 31, 2018, of which $16 million is expected to be reclassified to current income tax receivable in 2019 pursuant to the Tax Cuts and Jobs Act. Our corporate subsidiaries have state net operating loss carryforward benefits of $168 million, net of federal tax, which expire between 2019 and 2037. A valuation allowance of $98 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,		
	2018	2017	2016
Balance at beginning of year	$ 609	$ 615	$ 610
Additions attributable to tax positions taken in the current year	8	—	8
Additions attributable to tax positions taken in prior years	7	28	18
Reduction attributable to tax positions taken in prior years	—	(25)	(20)
Lapse of statute	—	(9)	(1)
Balance at end of year	$ 624	$ 609	$ 615

As of December 31, 2018, we have $620 million ($588 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2018, we recognized interest and penalties of less than $6 million. At December 31, 2018, we have interest and penalties accrued of $15 million, net of tax.

Sunoco, Inc. 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 for the 2004 through 2009 years. Sunoco, Inc.'s 2010 and 2011 years are extended for this issue with the IRS. In November 2016, the CFC ruled against Sunoco, Inc., and the United States Court of Appeals for the Federal Circuit (the "Federal Circuit") affirmed the CFC's ruling on November 1, 2018. Sunoco, Inc. subsequently filed a petition for rehearing with the Federal Circuit, and this was denied on January 24, 2019. Sunoco, Inc. is considering further review of the Federal Circuit's affirmation of the CFC's ruling. 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 balance sheets as of December 31, 2018 and 2017.

In November 2015, the Pennsylvania Commonwealth Court determined in Nextel Communications v. Commonwealth ("Nextel") that the Pennsylvania limitation on NOL carryforward deductions violated the uniformity clause of the Pennsylvania Constitution and struck the NOL limitation in its entirety. In October 2017, the Pennsylvania Supreme Court affirmed the decision with respect to the uniformity clause violation; however, the Court reversed with respect to the remedy and instead severed the flat-dollar limitation, leaving the percentage-based limitation intact. Nextel subsequently filed a petition for writ of certiorari with the United States Supreme Court, and this was denied on June 11, 2018. Now certain Pennsylvania taxpayers are proceeding with litigation in Pennsylvania state courts on issues not addressed by the Pennsylvania Supreme Court in Nextel, specifically, whether the Due Process and Equal Protection Clauses of the United States Constitution and the Remedies Clause of the Pennsylvania Constitution require a court to grant the taxpayer relief. Sunoco, Inc. has recognized approximately $67 million ($53 million after federal income tax benefits) in tax benefit based on previously filed tax returns and certain previously filed protective claims as relates to its cases currently held pending the Nextel matter. However, based upon the Pennsylvania Supreme Court's October 2017 decision, and because of uncertainty in the breadth of the application of the decision, we have reserved $34 million ($27 million after federal income tax benefits) against the receivable.

In general, ET and its subsidiaries are no longer subject to examination by the IRS, and most state jurisdictions, for the 2013 and prior tax years. However, Sunoco, Inc. and its subsidiaries remain subject to examination by the IRS for tax years beginning in 2007.

Sunoco, Inc. has been examined by the IRS for tax years through October 4, 2012. 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.

ET 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.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law. Among other provisions, the highest corporate federal income tax rate was reduced from 35% to 21% for taxable years beginning after December 31, 2017. As a result, the Partnership recognized a deferred tax benefit of $1.81 billion in December 2017. For the year ended December 31, 2018, the Partnership recorded an income tax expense due to pre-tax income at its corporate subsidiaries, partially offset by a state statutory rate reduction.

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

FERC Proceedings

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 FERC issued an audit report in October 2018. In response to the findings in the audit report, the Company expects to make certain changes to its processes, policies and procedures; however, the Company does not expect the findings to result in any changes to its financial statements.

By order issued January 16, 2019, the FERC initiated a review of Panhandle's existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Panhandle are just and reasonable and set the matter for hearing. Panhandle must file a cost and revenue study on or before April 1, 2019. An initial decision is expected to be issued in the first quarter of 2020. In addition, on November 30, 2018, Sea Robin filed a rate case pursuant to Section 4 of the Natural Gas Act. A hearing date is scheduled for October 23, 2019 and an initial decision is expected to be issued in the first quarter of 2020.

By order issued February 19, 2019, the FERC initiated a review of Southwest Gas Storage Company's existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Southwest Gas Storage Company are just and reasonable and set the matter for hearing. Southwest Gas Storage Company must file a cost and revenue study on or before May 6, 2019. The FERC is directing that an initial decision be issued within 47 weeks of the date the cost and revenue study is due.

Commitments

In the normal course of business, ETO 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. ETO 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.

Our joint venture agreements require that we funds our proportionate share of capital contributions to its unconsolidated affiliates. Such contributions will depend upon our 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 with typical initial terms of 5 to 15 years, with some having a term of 40 years or more. 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,		
	2018	2017	2016
Rental expense[(1)]	$ 139	$ 171	$ 161
Sublease rental income[(2)]	40	25	26
Net	$ 99	$ 146	$ 135

(1) Includes contingent rentals totaling $4 million, $16 million and $18 million for the years ended December 31, 2018, 2017 and 2016, respectively.

(2) Sublease rental income is included in other revenues in the accompanying statements of operations.

Future minimum lease commitments for such leases are:

Years Ending December 31:		
2019	$	104
2020		95
2021		74
2022		58
2023		50
Thereafter		220
Future minimum lease commitments		601
Less: Sublease rental income		(111)
Net future minimum lease commitments	$	490

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

On July 25, 2016, the United States Army Corps of Engineers ("USACE") issued permits to Dakota Access, LLC ("Dakota Access") to make two crossings of the Missouri River in North Dakota. The USACE also issued easements to allow the pipeline to cross land owned by the USACE adjacent to the Missouri River. On July 27, 2016, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia ("the Court") against the USACE and challenged the legality of these permits and claimed violations of the National Historic Preservation Act ("NHPA"). The SRST also sought a preliminary injunction to rescind the USACE permits while the case was pending, which the court denied on September 9, 2016. Dakota Access intervened in the case. The Cheyenne River Sioux Tribe ("CRST") also intervened. The SRST filed an amended complaint and added claims based on treaties between the SRST and the CRST and the United States and statutes governing the use of government property.

In February 2017, in response to a Presidential memorandum, the Department of the Army delivered an easement to Dakota Access allowing the pipeline to cross Lake Oahe. The CRST moved for a preliminary injunction and temporary restraining order ("TRO") to block operation of the pipeline, which motion was denied.

In June, 2017, the SRST and the CRST amended their complaints to incorporate religious freedom and other claims. In addition, the Oglala and Yankton Sioux tribes (collectively, "Tribes") have filed related lawsuits to prevent construction of the Dakota Access pipeline project. These lawsuits have been consolidated into the action initiated by the SRST. Several individual members of the Tribes have also intervened in the lawsuit asserting claims that overlap with those brought by the four Tribes.

On June 14, 2017, the Court ruled on SRST's and CRST's motions for partial summary judgment and the USACE's cross-motions for partial summary judgment. The Court concluded that the USACE had not violated trust duties owed to the Tribes and had generally complied with its obligations under the Clean Water Act, the Rivers and Harbors Act, the Mineral Leasing Act, the National Environmental Policy Act ("NEPA") and other related statutes; however, the Court remanded to the USACE three discrete issues for further analysis and explanation of its prior determinations under certain of these statutes.

In November 2017, the Yankton Sioux Tribe ("YST"), moved for partial summary judgment asserting claims similar to those already litigated and decided by the Court in its June 14, 2017 decision on similar motions by CRST and SRST. YST argues that the USACE and Fish and Wildlife Service violated NEPA, the Mineral Leasing Act, the Rivers and Harbors Act, and YST's treaty and trust rights when the government granted the permits and easements necessary for the pipeline.

On December 4, 2017, the Court imposed three conditions on continued operation of the pipeline during the remand process. First, Dakota Access must retain an independent third-party to review its compliance with the conditions and regulations governing its easements and to assess integrity threats to the pipeline. The assessment report was filed with the Court. Second, the Court has directed Dakota Access to continue its work with the Tribes and the USACE to revise and finalize its emergency spill response planning for the section of the pipeline crossing Lake Oahe. Dakota Access filed the revised plan with the Court. And third, the Court has directed Dakota Access to submit bi-monthly reports during the remand period disclosing certain inspection and maintenance information related to the segment of the pipeline running between the valves on either side of the Lake Oahe crossing. The first and second reports were filed with the court on December 29, 2017 and February 28, 2018, respectively.

On February 8, 2018, the Court docketed a motion by CRST to "compel meaningful consultation on remand." SRST then made a similar motion for "clarification re remand process and remand conditions." The motions seek an order from the Court directing the USACE as to how it should conduct its additional review on remand. Dakota Access pipeline and the USACE opposed both motions. On April 16, 2018, the Court denied both motions.

On March 19, 2018, the District Court denied YST's motion for partial summary judgment and instead granted judgment in favor of Dakota Access pipeline and the USACE on the claims raised in YST's motion. The Court concluded that YST's NHPA claims are moot because construction of the pipeline is complete and that the government's review process did not violate NEPA or the various treaties cited by the YST.

On May 3, 2018, the District Court ordered the USACE to file a status report by June 8, 2018 informing the Court when the USACE expects the remand process to be complete. On June 8, 2018, the USACE filed a status report stating that they will conclude the remand process by August 10, 2018. On August 7, 2018, the USACE informed the Court that they will need until August 31, 2018 to finish the remand process. On August 31, 2018, the USACE informed the Court that it had completed the remand process and that it had determined that the three issues remanded by the Court had been correctly decided. On October 1, 2018, the USACE produced a detailed remand analysis document supporting that determination. The plaintiff Tribes and certain of the individuals have sought leave of the Court to amend their complaints to challenge the remand process and the USACE's decision on remand. The Court is currently considering proposed schedules for a final round of summary judgment briefing, and ETO expects that the Court will issue a final determination once that briefing is concluded.

On January 3, 2019, the Court granted the Tribes' requests to supplement their respective complaints challenging the remand process, subject to defendants' right to argue later that such supplementation may be overbroad and not permitted by law. On January 10, 2019, the Court denied the Oglala Sioux Tribe's motion to amend its complaint to expand one of its pre-remand claims.

On January 17, 2019, the DOJ, on behalf of the USACE, moved to stay the litigation in light of the lapse in appropriations for the DOJ. The Tribes' and individual plaintiffs have opposed that request. The motion is currently pending before the Court.

While Energy Transfer believes that the pending lawsuits are unlikely to halt or suspend operation of the pipeline, we cannot assure this outcome. Energy Transfer 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 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. Lone Star is still quantifying the extent of its incurred and ongoing damages and has or will be seeking reimbursement for these losses.

MTBE Litigation

Sunoco, Inc. and Sunoco, Inc. (R&M) (now known as Sunoco (R&M), LLC) (collectively, "Sunoco") are defendants in lawsuits alleging MTBE contamination of groundwater. The plaintiffs, state-level governmental entities, assert product liability, nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices claims. The plaintiffs 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, 2018, Sunoco is a defendant in six cases, including one case each initiated by the States of Maryland, Vermont and Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants Energy Transfer Partners, L.P., ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals, L.P.

In late July 2018, the Court in the Vermont matter denied the State of Vermont's motion to amend its complaint to add specific allegations regarding some of the sites the court previously dismissed. The State of Vermont and the defendants reached a settlement in principle to resolve the remaining statewide Vermont Case in September 2018. The parties are in the process of finalizing settlement documents.

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. 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 such adverse determination occurs, but such an adverse determination likely would not have a material adverse effect on the Partnership's consolidated financial position.

Regency Merger Litigation

Purported Regency unitholders filed lawsuits in state and federal courts in Dallas and Delaware asserting claims relating to the Regency-ETP merger (the "Regency Merger"). All but one Regency Merger-related lawsuits have been dismissed. On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint in the Court of Chancery of the State of Delaware (the "Regency Merger Litigation"), on behalf of Regency's common unitholders against Regency GP, LP; Regency GP LLC; ET, ETO, ETP GP, and the members of Regency's board of directors ("Defendants").

The Regency Merger Litigation 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. On March 29, 2016, the Delaware Court of Chancery granted Defendants' motion to dismiss the lawsuit in its entirety. Dieckman appealed. On January 20, 2017, the Delaware Supreme Court reversed the judgment of the Court of Chancery. On May 5, 2017, Plaintiff filed an Amended Verified Class Action Complaint. Defendants then filed Motions to Dismiss the Amended Complaint and a Motion to Stay Discovery on May 19, 2017. On February 20, 2018, the Court of Chancery issued an Order granting in part and denying in part the motions to dismiss, dismissing the claims against all defendants other than Regency GP, LP and Regency GP LLC (the "Regency Defendants"). On March 6, 2018, the Regency Defendants filed their Answer to Plaintiff's Verified Amended Class Action Complaint. Trial is currently set for September 23-27, 2019.

The Regency Defendants cannot predict the outcome of the Regency Merger Litigation or any lawsuits that might be filed subsequent to the date of this filing; nor can the Regency Defendants predict the amount of time and expense that will be required to resolve the Regency Merger Litigation. The Regency Defendants believe the Regency Merger Litigation is without merit and intend to vigorously defend against it and any others that may be filed in connection with the Regency Merger.

Energy Transfer Merger Litigation

On September 17, 2018, William D. Warner ("Plaintiff"), a purported Energy Transfer Partners, L.P. unitholder, filed a putative class action asserting violations of various provisions of the Securities Exchange Act of 1934 and various rules promulgated thereunder in connection with the Energy Transfer Merger against Energy Transfer Partners, L.P., Kelcy L. Warren, Michael K. Grimm, Marshall S. McCrea, Matthew S. Ramsey, David K. Skidmore, and W. Brett Smith ("Defendants"). Plaintiff specifically alleged that the proxy statement related to the Energy Transfer Merger omitted and/or misrepresented material information. On December 17, 2018, Plaintiff voluntarily dismissed his lawsuit.

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

On January 27, 2014, a trial commenced between ETO 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 ETO against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETO. The jury also found that ETO owed Enterprise $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETO and awarded ETO $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETO 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 filed a notice of appeal with the Court of Appeals. On July 18, 2017, the Court of Appeals issued its opinion and reversed the trial court's judgment. ETO's motion for rehearing to the Court of Appeals was denied. On June 8, 2018, the Texas Supreme Court ordered briefing on the merits. ETO's petition for review remains under consideration by the Texas Supreme Court.

Litigation Filed By or Against Williams

On April 6, 2016, The Williams Companies, Inc. ("Williams") filed a complaint against ET and LE GP in the Delaware Court of Chancery (the "First Delaware Williams Litigation"). Williams sought, among other things, to (a) rescind the issuance of the Partnership's Series A Convertible Preferred Units (the "Issuance") and (b) invalidate an amendment to ET's partnership agreement that was adopted on March 8, 2016 as part of the Issuance.

On May 3, 2016, ET and LE GP filed an answer and counterclaim in the First Delaware Williams Litigation. The counterclaim asserts in general that Williams materially breached its obligations under the ET-Williams merger agreement (the "Merger Agreement") by (a) blocking ET's attempts to complete a public offering of the Series A Convertible Preferred Units, including, among other things, by declining to allow Williams' independent registered public accounting firm to provide the auditor consent required to be included in the registration statement for a public offering and (b) bringing a lawsuit concerning the Issuance against Mr. Warren in the District Court of Dallas County, Texas, which the Texas state court later dismissed based on the Merger Agreement's forum-selection clause.

On May 13, 2016, Williams filed a second lawsuit in the Delaware Court of Chancery (the "Court") against ET and LE GP and added Energy Transfer Corp LP, ETE Corp GP, LLC, and Energy Transfer Equity GP, LLC as additional defendants (collectively, "Defendants") (the "Second Delaware Williams Litigation"). In general, Williams alleged that Defendants breached the Merger Agreement by (a) failing to use commercially reasonable efforts to obtain from Latham & Watkins LLP ("Latham") the delivery of a tax opinion concerning Section 721 of the Internal Revenue Code ("721 Opinion"), (b) breaching a representation and warranty in the Merger Agreement concerning Section 721 of the Internal Revenue Code, and (c) taking actions that allegedly delayed the SEC in declaring the Form S-4 filed in connection with the merger (the "Form S-4") effective. Williams asked the Court, in general, to (a) issue a declaratory judgment that ET breached the Merger Agreement, (b) enjoin ET from terminating the Merger Agreement on the basis that it failed to obtain a 721 Opinion, (c) enjoin ET from terminating the Merger Agreement on the basis that the transaction failed to close by the outside date, and (d) force ET to close the merger or take various other affirmative actions.

ET filed an answer and counterclaim in the Second Delaware Williams Litigation. In addition to the counterclaims previously asserted, ET asserted that Williams materially breached the Merger Agreement by, among other things, (a) modifying or qualifying the Williams board of directors' recommendation to its stockholders regarding the merger, (b) failing to provide material information to ET for inclusion in the Form S-4 related to the merger, (c) failing to facilitate the financing of the merger, (d) failing to use its reasonable best efforts to consummate the merger, and (e) breaching the Merger Agreement's forum-selection clause. ET sought, among other things, a declaration that it could validly terminate the Merger Agreement after June 28, 2016 in the event that Latham was unable to deliver the 721 Opinion on or prior to June 28, 2016.

After a two-day trial on June 20 and 21, 2016, the Court ruled in favor of ET on Williams' claims in the Second Delaware Williams Litigation and issued a declaratory judgment that ET could terminate the merger after June 28, 2016 because of Latham's inability to provide the required 721 Opinion. The Court also denied Williams' requests for injunctive relief. The Court did not reach a decision regarding Williams' claims related to the Issuance or ET's counterclaims. Williams filed a notice of appeal to the Supreme Court of Delaware on June 27, 2016. Williams filed an amended complaint on September 16, 2016 and sought a $410 million termination fee, and Defendants filed amended counterclaims and affirmative defenses. In response, Williams filed a motion to dismiss Defendants' amended counterclaims and to strike certain of Defendants' affirmative defenses.

On March 23, 2017, the Delaware Supreme Court affirmed the Court's ruling on the June trial, and as a result, Williams has conceded that its $10 billion damages claim is foreclosed, although its $410 million termination fee claim remains pending.

On December 1, 2017, the Court issued a Memorandum Opinion granting Williams' motion to dismiss in part and denying Williams' motion to dismiss in part.

Defendants cannot predict the outcome of the First Delaware Williams Litigation, the Second Delaware Williams Litigation, or any lawsuits that might be filed subsequent to the date of this filing; nor can Defendants predict the amount of time and expense that will be required to resolve these lawsuits. Defendants believe that Williams' claims are without merit and intend to defend vigorously against them.

Unitholder Litigation Relating to the Issuance

On April 12, 2016, two purported ET unitholders (the "Issuance Plaintiffs") filed putative class action lawsuits against ET, LE GP, Kelcy Warren, John McReynolds, Marshall McCrea, Matthew Ramsey, Ted Collins, K. Rick Turner, William Williams, Ray Davis, and Richard Brannon (collectively, the "Issuance Defendants") in the Delaware Court of Chancery (the "Issuance Litigation"). Another purported ET unitholder, Chester County Employees' Retirement Fund, later joined the Issuance Litigation.

The Issuance Plaintiffs allege that the Issuance breached various provisions of ET's partnership agreement. The Issuance Plaintiffs seek, among other things, preliminary and permanent injunctive relief that (a) prevents ET from making distributions to holders of the Series A Convertible Preferred Units and (b) invalidates an amendment to ET's partnership agreement that was adopted on March 8, 2016 as part of the Issuance.

On August 29, 2016, the Issuance Plaintiffs filed a consolidated amended complaint, and in addition to the injunctive relief described above, seek class-wide damages allegedly resulting from the Issuance.

The matter was tried in front of Vice Chancellor Glasscock on February 19-21, 2018. Post-trial arguments were heard on April 16, 2018. In a post-trial opinion dated May 17, 2018, the Court found that one provision of the Issuance breached ET's partnership agreement but that this breach caused no damages. The Court denied Plaintiffs' requests for injunctive relief and declined to award damages other than nominal damages. Plaintiffs subsequently filed a motion seeking $8.5 million in attorneys' fees and expenses from the Issuance Defendants, which the Issuance Defendants have opposed.

The Issuance Defendants cannot predict the outcome of the Issuance Litigation or any lawsuits that might be filed subsequent to the date of this filing; nor can the Issuance Defendants predict the amount of time and expense that will be required to resolve the Issuance Litigation. The Issuance Defendants believe the Issuance Litigation is without merit and intend to defend vigorously against it and any other actions challenging the Issuance.

Rover

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and Pretec Directional Drilling, LLC ("Pretec") seeking to recover approximately $2.6 million in civil penalties allegedly owed and certain injunctive relief related to permit compliance. Laney Directional Drilling Co., Atlas Trenchless, LLC, Mears Group, Inc., D&G Directional Drilling, Inc. d/b/a D&G Directional Drilling, LLC, and B&T Directional Drilling, Inc. (collectively, with Rover and Pretec, "Defendants") were added as defendants on April 17, 2018 and July 18, 2018.

Ohio EPA alleges that the Defendants illegally discharged millions of gallons of drilling fluids into Ohio's waters that caused pollution and degraded water quality, and that the Defendants harmed pristine wetlands in Stark County. Ohio EPA further alleges that the Defendants caused the degradation of Ohio's waters by discharging pollution in the form of sediment-laden storm water into Ohio's waters and that Rover violated its hydrostatic permits by discharging effluent with greater levels of pollutants than those permits allowed and by not properly sampling or monitoring effluent for required parameters or reporting those alleged violations. Rover and other Defendants filed several motions to dismiss and Ohio EPA filed a motion in opposition. The State's opposition to those motions was filed on October 12, 2018. Rover and other Defendants filed their replies on November 2, 2018. The court has not yet ruled on the motion. The State requested oral argument on the motion, but no argument has been scheduled to date.

In January 2018, Ohio EPA sent a letter to the FERC to express concern regarding drilling fluids lost down a hole during horizontal directional drilling ("HDD") operations as part of the Rover Pipeline construction. Rover sent a January 24 response to the FERC and stated, among other things, that as Ohio EPA conceded, Rover was conducting its drilling operations in accordance with specified procedures that had been approved by the FERC and reviewed by the Ohio EPA. In addition, although the HDD operations were crossing the same resource as that which led to an inadvertent release of drilling fluids in April 2017, the drill in 2018 had been redesigned since the original crossing. Ohio EPA expressed concern that the drilling fluids could deprive organisms in the wetland of oxygen. Rover, however, has now fully remediated the site, a fact with which Ohio EPA concurs. Construction of Rover is now complete and the pipeline is fully operational.

Bayou Bridge

On January 11, 2018, environmental groups and a trade association filed suit against the USACE in the United States District Court for the Middle District of Louisiana. Plaintiffs allege that the USACE's issuance of permits authorizing the construction of the Bayou Bridge Pipeline through the Atchafalaya Basin ("Basin") violated the National Environmental Policy Act, the Clean Water Act, and the Rivers and Harbors Act. They asked the district court to vacate these permits and to enjoin construction of the project through the Basin until the USACE corrects alleged deficiencies in its decision-making process.

ETO, through its subsidiary Bayou Bridge Pipeline, LLC ("Bayou Bridge"), intervened on January 26, 2018. On March 27, 2018, Bayou Bridge filed an answer to the complaint.

On January 29, 2018, Plaintiffs filed motions for a preliminary injunction and TRO. United States District Court Judge Shelly Dick denied the TRO on January 30, 2018, but subsequently granted the preliminary injunction on February 23, 2018. On February 26, 2018, Bayou Bridge filed a notice of appeal and a motion to stay the February 23, 2018 preliminary injunction order. On February 27, 2018, Judge Dick issued an opinion that clarified her February 23, 2018 preliminary injunction order and denied Bayou Bridge's February 26, 2018 motion to stay as moot. On March 1, 2018, Bayou Bridge filed a new notice of appeal and motion to stay the February 27, 2018 preliminary injunction order in the district court. On March 5, 2018, the district court denied the March 1, 2018 motion to stay the February 27, 2018 order.

On March 2, 2018, Bayou Bridge filed a motion to stay the preliminary injunction in the Fifth Circuit. On March 15, 2018, the Fifth Circuit granted a stay of injunction pending appeal and found that Bayou Bridge "is likely to succeed on the merits of its claim that the district court abused its discretion in granting a preliminary injunction." Oral arguments were heard on the merits of the appeal, that is, whether the district court erred in granting the preliminary injunction in the Fifth Circuit on April 30, 2018. The district court has stayed the merits case pending decision of the Fifth Circuit. On May 10, 2018, the District Court stayed the litigation pending a decision from the Fifth Circuit. On July 6, 2018, the Fifth Circuit vacated the Preliminary Injunction and remanded the case back to the District Court. Construction is ongoing.

On August 14, 2018, Plaintiffs sought leave of court to amend their complaint to add an "as applied" challenge to the USACE's application of the Louisiana Rapid Assessment Method to Bayou Bridge's permits. Defendants' filed motions in opposition on September 18, 2018.

On September 11, 2018, Plaintiffs filed a motion for partial summary judgment on the issue of the USACE's analysis of the risks of an oil spill once the pipeline is in operation. On November 6, 2018 the court struck plaintiffs' motion as premature.

At an October 2, 2018 scheduling conference, the USACE agreed to lodge the administrative record for Plaintiffs' original complaint, which it has done. Challenges to the completeness of the record have been briefed and are currently pending before the Court. At the October 18 conference, the Court also scheduled summary judgment briefing on Plaintiffs' original complaint; briefing is scheduled to conclude by Spring of 2019.

On December 28, 2018, Judge Dick issued a General Order for the Middle District of Louisiana holding in abeyance all civil matters where the United States is a party. Notwithstanding the General Order, on January 11, 2019, Plaintiffs filed a Motion for Summary Judgment on their National Environmental Policy Act and Clean Waters Act claims.

On January 11, 2019, Plaintiffs filed a Motion for Summary Judgment on its National Environmental Policy Act and Coastal Water Authority claims. On January 23, 2019, Plaintiffs filed a Second Motion for Preliminary Injunction based on the alleged permit violations in the January 7, 2019 letter, which the Court later denied. On February 11, 2019, the Court denied Plaintiffs' August 14, 2018 motion for leave to amend their complaint.

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, 2018 and 2017, accruals of approximately $55 million and $56 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.

On April 25, 2018, and as amended on April 30, 2018, State Senator Andrew Dinniman filed a Formal Complaint and Petition for Interim Emergency Relief ("Complaint") against SPLP before the Pennsylvania Public Utility Commission ("PUC"). Specifically, the Complaint alleges that (i) the services and facilities provided by the Mariner East Pipeline ("ME1," "ME2" or "ME2x") in West Whiteland Township ("the Township") are unreasonable, unsafe, inadequate, and insufficient for, among other reasons, selecting an improper and unsafe route through densely populated portions of the Township with homes, schools, and infrastructure and causing inadvertent returns and sinkholes during construction because of unstable geology in the Township; (ii) SPLP failed to warn the public of the dangers of the pipeline; (iii) the construction of ME2 and ME2x increases the risk of damage to the existing co-located ME1 pipeline; and (iv) ME1, ME2 and ME2x are not public utility facilities. Based on these allegations, Senator Dinniman's Complaint seeks emergency relief by way of an order (i) prohibiting construction of ME2 and ME2x in the Township; (ii) prohibiting operation of ME1; (iii) in the alternative to (i) and (ii) prohibiting the construction of ME2 and ME2x and the operation of ME1 until SPLP fully assesses and the PUC approves the condition, adequacy, efficiency, safety, and reasonableness of those pipelines and the geology in which they sit; (iv) requiring SPLP to release to the public its written integrity management plan and risk analysis for these pipelines; and (v) finding that these pipelines are not public utility facilities. In short, the relief, if granted, would continue the suspension of operation of ME1 and suspend further construction of ME2 and ME2x in the Township.

Following a hearing on May 7, 2018 and 10, 2018, Administrative Law Judge Elizabeth H. Barnes ("ALJ") issued an Order on May 24, 2018 that granted Senator Dinniman's petition for interim emergency relief and required SPLP to shut down ME1, to discontinue construction of ME2 and ME2x within the Township, and required SPLP to provide various types of information and perform various geotechnical and geophysical studies within the Township. The ALJ's Order was immediately effective, and SPLP complied by shutting down service on ME1 and discontinuing all construction in the Township on ME2 and ME2x. The ALJ's Order was automatically certified as a material question to the PUC, which issued an Opinion and Order on June 15, 2018 (following a public meeting on June 14, 2018) that reversed in part and affirmed in part the ALJ's Order. PUC's Opinion and Order permitted SPLP to resume service on ME1, but continued the shutdown of construction on ME2 and ME2x pending the submission of the following three types of information to PUC: (i) inspection and testing protocols; (ii) comprehensive emergency response plan; and (iii) safety training curriculum for employees and contractors. SPLP submitted the required information on June 22, 2018. On July 2, 2018, Senator Dinniman and intervenors responded to the submission. SPLP is also required to provide an affidavit that the Pennsylvania Department of Environmental Protection ("PADEP") has issued appropriate approvals for construction of ME2 and ME2x in the Township before recommencing construction of ME2 and ME2x locations within the Township. SPLP submitted all necessary affidavits. On August 2, 2018 the PUC entered an Order lifting the stay of construction on ME2 and ME2x in the Township with respect to four of the eight areas within the Township where the necessary environmental permits had been issued. Subsequently, after PADEP's issuance of permit modifications for two of the four remaining construction sites, the PUC lifted the construction stay on those two sites as well. Also on August 2, 2018, the PUC ratified its prior action by notational voting of certifying for interlocutory appeal to the Pennsylvania Commonwealth Court the legal issue of whether Senator Dinniman has standing to pursue this matter. Sunoco submitted a petition for permission to appeal on this issue of standing. Senator Dinniman and intervenors opposed that petition. On September 27, 2018, the Commonwealth Court issued an Order that certified for appeal the issue of Senator Dinniman's standing. The Order stays all proceedings in the PUC.

Also on August 2, 2018, the PUC ratified its prior action by notational voting of certifying for interlocutory appeal to the Pennsylvania Commonwealth Court the legal issue of whether Senator Dinniman has standing to pursue the action. SPLP submitted a petition for permission to appeal on this issue of standing. Senator Dinniman and intervenors opposed that petition. On September 27, 2018, the Commonwealth Court issued an Order that certified for appeal the issue of Senator Dinniman's standing. The Order stays all proceedings in the PUC.

On July 25, 2017, the Pennsylvania Environmental Hearing Board ("EHB") issued an order to SPLP to cease HDD activities in Pennsylvania related to the Mariner East 2 project. On August 1, 2017 the EHB lifted the order as to two drill locations. On August 3, 2017, the EHB lifted the order as to 14 additional locations. The EHB issued the order in response to a complaint filed by environmental groups against SPLP and the PADEP. The EHB Judge encouraged the parties to pursue a settlement with respect to the remaining HDD locations and facilitated a settlement meeting. On August 7, 2017 a final settlement was reached. A stipulated order has been submitted to the EHB Judge with respect to the settlement. The settlement agreement requires that SPLP reevaluate the design parameters of approximately 26 drills on the Mariner East 2 project and approximately 43 drills on the Mariner East 2X project. The settlement agreement also provides a defined framework for approval by PADEP for these drills to proceed after reevaluation. Additionally, the settlement agreement requires modifications to several of the HDD plans that are part of the PADEP permits. Those modifications have been completed and agreed to by the parties and the reevaluation of the drills has been initiated by the company. On July 31, 2018 the underlying permit appeals in which the above settlements occurred were withdrawn in a settlement between the appellants and PADEP. That settlement did not involve SPLP.

In addition, on June 27, 2017 and July 25, 2017, the PADEP entered into a Consent Order and Agreement with SPLP regarding inadvertent returns of drilling fluids at three HDD locations in Pennsylvania related to the Mariner East 2 project. Those agreements require SPLP to cease HDD activities at those three locations until PADEP reauthorizes such activities and to submit a corrective action plan for agency review and approval. SPLP has fulfilled the requirements of those agreements and has been authorized by PADEP to resume drilling the locations.

On September 10, 2018, a pipeline release and fire occurred on the Revolution Pipeline in the vicinity of Ivy Lane located in Center Township, Beaver County, Pennsylvania. There were no injuries but there were evacuations of local residents as a precautionary measure. The Pennsylvania Department of Environmental Protection ("PADEP") and the Pennsylvania Public Utility Commission ("PUC") are investigating the incident. On October 29, 2018, PADEP issued a Compliance Order requiring our subsidiary, ETC Northeast, to cease all earth disturbance activities at the site (except as necessary to repair and maintain existing Best Management Practices ("BMPs") and temporarily stabilize disturbed areas), implement and/or maintain the Erosion and Sediment BMPs at the site, stake the limit of disturbance, identify and report all areas of non-compliance, and submit an updated Erosion and Sediment Control Plan, a Temporary Stabilization Plan, and an updated Post Construction Stormwater Management Plan. The scope of the Compliance Order has been expanded to include the disclosure to PADEP of alleged violations of environmental permits with respect to various construction and post-construction activities and restoration obligations along the 42-mile route of the Revolution line. ETC Northeast filed an appeal of the Compliance Order with the Pennsylvania Environmental Hearing Board.

On February 8, 2019, PADEP filed a Petition to Enforce the Compliance Order with Pennsylvania's Commonwealth Court. The Court issued an Order on February 14, 2019 requiring the submission of an answer to the Petition on or before March 12, 2019, and scheduling a hearing on the Petition for March 26, 2019. PADEP has also and issued a Permit Hold on any requests for approvals/permits or permit amendments made by us or any of our subsidiaries for any projects in Pennsylvania pursuant to the state's water laws. We continue to work through these issues with PADEP.

No amounts have been recorded in our December 31, 2018 or 2017 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

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, natural resource damages, 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.

In February 2017, we received letters from the DOJ on behalf of EPA and LDEQ notifying SPLP and Mid-Valley that enforcement actions were being pursued for three separate crude oil releases: (a) an estimated 550 barrels released from the Colmesneil-to-Chester pipeline in Tyler County, Texas ("Colmesneil") which allegedly occurred in February of 2013; (b) an estimated 4,509 barrels released from the Longview-to-Mayersville pipeline in Caddo Parish, Louisiana (a/k/a Milepost 51.5) which allegedly occurred in October of 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma which allegedly occurred in January of 2015. In January of 2019, an Consent Decree approved by all parties as well as an accompanying Complaint was filed in the United States District Court for the Western District of Louisiana seeking public comment and final court approval to resolve all penalties with DOJ and LDEQ for the three releases. The Consent Decree requires certain injunctive relief to be completed on the Longview-to-Mayersville pipeline within three years but the injunctive relief is not expected to have any material impact on operations. In addition to resolution of the civil penalty and injunctive relief, we continue to discuss natural resource damages with the Louisiana trustees.

On January 3, 2018, PADEP issued an Administrative Order to SPLP directing that work on the Mariner East 2 and 2X pipelines be stopped. The Administrative Order detailed alleged violations of the permits issued by PADEP in February

2017, during the construction of the project. SPLP began working with PADEP representatives immediately after the Administrative Order was issued to resolve the compliance issues. Those compliance issues could not be fully resolved by the deadline to appeal the Administrative Order, so SPLP took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, SPLP entered into a Consent Order and Agreement with PADEP that (i) withdraws the Administrative Order; (ii) establishes requirements for compliance with permits on a going forward basis; (iii) resolves the non-compliance alleged in the Administrative Order; and (iv) conditions restart of work on an agreement by SPLP to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, SPLP admits to the factual allegations, but does not admit to the conclusions of law that were made by PADEP. PADEP also found in the Consent Order and Agreement that SPLP had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. SPLP concurrently filed a request to the Pennsylvania Environmental Hearing Board to discontinue the appeal of the Administrative Order. That request was granted on February 8, 2018.

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.
- 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, 2018, , Sunoco, Inc. had been named as a PRP at approximately 41 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,	
	2018	2017
Current	$ 42	$ 35
Non-current	295	337
Total environmental liabilities	$ 337	$ 372

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, 2018 and 2017, the Partnership recorded $48 million and $37 million, respectively, of expenditures related to environmental cleanup programs.

Our pipeline operations are subject to regulation by the United States Department of Transportation under the Pipeline Hazardous Materials Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Our operations are also subject to the requirements of OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, the Occupational Safety and Health Administration'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. REVENUE

The following disclosures discuss the Partnership's revised revenue recognition policies upon the adoption of ASU 2014-09 on January 1, 2018, as discussed in Note 1. These policies were applied to the current period only, and the amounts reflected in the Partnership's consolidated financial statements for the years ended December 31, 2017 and 2016 were recorded under the Partnership's previous accounting policies.

Disaggregation of revenue

The major types of revenue within our reportable segment, are as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;
- crude oil transportation and services;
- investment in Sunoco LP;
    - fuel distribution and marketing;
    - all other;
- investment in USAC;
    - contract operations;
    - retail parts and services; and
- all other.

Note 16 depicts the disaggregation of revenue by segment, with revenue amounts reflected in accordance with ASC Topic 606 for 2018 and ASC Topic 605 for 2017 and 2016.

Intrastate transportation and storage revenue

Our intrastate transportation and storage segment's revenues are determined primarily by the volume of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines or that is injected or withdrawn into or out of our storage facilities. Firm transportation and storage contracts require customers to pay certain minimum fixed fees regardless of the volume of commodity they transport or store. These contracts typically include a variable incremental charge based on the actual volume of transportation commodity throughput or stored commodity injected/withdrawn. Under interruptible transportation and storage contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of commodity they transport across our pipelines or inject/withdraw into or out of our storage facilities. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or storage) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of service, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer's request. Revenue is recognized for interruptible contracts at the time the services are performed.

Interstate transportation and storage revenue

Our interstate transportation and storage segment's revenues 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 or that is injected into or withdrawn out of our storage facilities. Our interstate transportation and storage segment's contracts can be firm or interruptible. Firm transportation and storage contracts require customers to pay certain minimum fixed fees regardless of the volume of commodity transported or stored. In exchange for such fees, we must stand ready to perform a contractually agreed-upon minimum volume of services whenever the customer requests such services. These contracts typically include a variable incremental charge based on the actual volume of transportation commodity throughput or stored commodity injected or withdrawn. Under interruptible transportation and storage contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of commodity they transport across our pipelines or inject into or withdraw out of our storage facilities. Consequently, we are not required to stand ready to provide any contractually agreed-upon volume of service, but instead provides the services based on existing capacity at the time the customer requests the services. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or storage) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of services, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer's request. Revenue is recognized for interruptible contracts at the time the services are performed.

Lake Charles LNG's revenues are primarily derived from terminalling services for shippers by receiving LNG at the facility for storage and delivering such LNG to shippers, either in liquid state or gaseous state after regasification. Lake Charles LNG derives all of its revenue from a series of long term contracts with a wholly-owned subsidiary of Royal Dutch Shell plc ("Shell"). Terminalling revenue is generated from fees paid by Shell for storage and other associated services at the terminal. Payment for services under these contracts are typically due the month after the services have been performed.

The terminalling agreements are considered to be firm agreements, because they include fixed fee components that are charged regardless of the volumes transported by Shell or services provided at the terminal.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (terminalling) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

Midstream revenue

Our midstream segment's revenues are derived primarily from margins we earn for natural gas volumes that are gathered, processed, and/or transported for our customers. The various types of revenue contracts our midstream segment enters into include:

Fixed fee gathering and processing: Contracts under which we provide gathering and processing services in exchange for a fixed cash fee per unit of volume. Revenue for cash fees is recognized when the service is performed.

Keepwhole: Contracts under which we gather raw natural gas from a third party producer, process the gas to convert it to pipeline quality natural gas, and redeliver to the producer a thermal-equivalent volume of pipeline quality natural gas. In exchange for these services, we retain the NGLs extracted from the raw natural gas received from the producer as well as cash fees paid by the producer. The value of NGLs retained as well as cash fees is recognized as revenue when the services are performed.

Percent of Proceeds ("POP"): Contracts under which we provide gathering and processing services in exchange for a specified percentage of the producer's commodity ("POP percentage") and also in some cases additional cash fees. The two types of POP revenue contracts are described below:

- *In-Kind POP:* We retain our POP percentage (non-cash consideration) and also any additional cash fees in exchange for providing the services. We recognize revenue for the non-cash consideration and cash fees at the time the services are performed.
- *Mixed POP:* We purchase NGLs from the producer and retain a portion of the residue gas as non-cash consideration for services provided. We may also receive cash fees for such services. Under Topic 606, these agreements were determined to be hybrid agreements which were partially supply agreements (for the NGLs we purchased) and customer agreements (for the services provided related to the product that was returned to the customer). Given that these are hybrid agreements, we split the cash and non-cash consideration between revenue and a reduction of costs based on the value of the service provided vs. the value of the supply received.

Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligations with respect to our midstream segment's contracts are to provide gathering, transportation and processing services, each of which would be completed on or about the same time, and each of which would be recognized on the same line item on the income statement, therefore identification of separate performance obligations would not impact the timing or geography of revenue recognition.

Certain contracts of our midstream segment include throughput commitments under which customers commit to purchasing a certain minimum volume of service over a specified time period. If such volume of service is not purchased by the customer, deficiency fees are billed to the customer. In some cases, the customer is allowed to apply any deficiency fees paid to future purchases of services. In such cases, we defer revenue recognition until the customer uses the deficiency fees for services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints.

NGL and refined products transportation and services revenue

Our NGL and refined products segment's revenues are primarily derived from transportation, fractionation, blending, and storage of NGL and refined products as well as acquisition and marketing activities. Revenues are generated utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGL markets. Transportation, fractionation, and storage revenue is generated from fees charged to customers under a combination of firm and interruptible contracts. Firm contracts are in the form of take-or-pay arrangements where certain fees will be charged to customers regardless of the volume of service they request for any given period. Under interruptible contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of service provided for any given period. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation, fractionation, blending, or storage) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this “stand-ready” service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of services, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer’s request. Revenue is recognized for interruptible contracts at the time the services are performed.

Acquisition and marketing contracts are in most cases short-term agreements involving purchase and/or sale of NGLs and other related hydrocarbons at market rates. These contracts were not affected by ASC 606.

Crude oil transportation and services revenue

Our crude oil transportation and service segment are primarily derived from provide transportation, terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest and northeastern United States. Crude oil transportation revenue is generated from tariffs paid by shippers utilizing our transportation services and is generally recognized as the related transportation services are provided. Crude oil terminalling revenue is generated from fees paid by customers for storage and other associated services at the terminal. Crude oil acquisition and marketing revenue is generated from sale of crude oil acquired from a variety of suppliers to third parties. Payment for services under these contracts are typically due the month after the services have been performed.

Certain transportation and terminalling agreements are considered to be firm agreements, because they include fixed fee components that are charged regardless of the volume of crude oil transported by the customer or services provided at the terminal. For these agreements, any fixed fees billed in excess of services provided are not recognized as revenue until the earlier of (i) the time at which the customer applies the fees against cost of service provided in a later period, or (ii) the customer becomes unable to apply the fees against cost of future service due to capacity constraints or contractual terms.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or terminalling) daily over the life of the contract, which is fundamentally a “stand-ready” service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this “stand-ready” service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of service, but such promise is made on a case-by-case basis at the time the customer requests the service and/or product and we accept the customer’s request. Revenue is recognized for interruptible contracts at the time the services are performed.

Acquisition and marketing contracts are in most cases short-term agreements involving purchase and/or sale of crude oil at market rates. These contracts were not affected by ASC 606.

Sunoco LP’s fuel distribution and marketing revenue

Sunoco LP’s fuel distribution and marketing operations earn revenue from the following channels: sales to Dealers, sales to Distributors, Unbranded Wholesale Revenue, Commission Agent Revenue, Rental Income and Other Income. Motor fuel revenue consists primarily of the sale of motor fuel under supply agreements with third party customers and affiliates. Fuel supply contracts with Sunoco LP’s customers generally provide that Sunoco LP distribute motor fuel at a formula price based on published rates, volume-based profit margin, and other terms specific to the agreement. The customer is invoiced the agreed-upon price with most payment terms ranging less than 30 days. If the consideration promised in a contract includes a variable amount, Sunoco LP estimates the variable consideration amount and factors in such an estimate to determine the transaction price under the expected value method.

Revenue is recognized under the motor fuel contracts at the point in time the customer takes control of the fuel. At the time control is transferred to the customer the sale is considered final, because the agreements do not grant customers the right to return motor fuel. Under the new standard, to determine when control transfers to the customer, the shipping terms of the contract are assessed as shipping terms are considered a primary indicator of the transfer of control. For FOB shipping point terms, revenue is recognized at the time of shipment. The performance obligation with respect to the sale of goods is satisfied at the time of shipment since the customer gains control at this time under the terms. Shipping and/or handling costs that occur before the customer obtains control of the goods are deemed to be fulfillment activities and are accounted for as fulfillment costs. Once the goods are shipped, Sunoco LP is precluded from redirecting the shipment to another customer and revenue is recognized.

Commission agent revenue consists of sales from commission agent agreements between Sunoco LP and select operators. Sunoco LP supplies motor fuel to sites operated by commission agents and sells the fuel directly to the end customer. In commission agent arrangements, control of the product is transferred at the point in time when the goods are sold to the end customer. To reflect the transfer of control, Sunoco LP recognizes commission agent revenue at the point in time fuel is sold to the end customer.

Sunoco LP receives rental income from leased or subleased properties. Revenue from leasing arrangements for which Sunoco LP is the lessor are recognized ratably over the term of the underlying lease.

Sunoco LP's all other revenue

Sunoco LP's all other operations earn revenue from the following channels: Motor Fuel Sales, Rental Income and Other Income. Motor Fuel Sales consist of fuel sales to consumers at company-operated retail stores. Other income includes merchandise revenue that comprises the in-store merchandise and food service sales at company-operated retail stores, and other revenue that represents a variety of other services within Sunoco LP's all other operations including credit card processing, car washes, lottery, automated teller machines, money orders, prepaid phone cards and wireless services. Revenue from all other operations is recognized when (or as) the performance obligations are satisfied (i.e. when the customer obtains control of the good or the service is provided).

USAC's contract operations revenue

USAC's revenue from contracted compression, station, gas treating and maintenance services is recognized ratably under its fixed-fee contracts over the term of the contract as services are provided to its customers. Initial contract terms typically range from six months to five years, however USAC usually continues to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. USAC primarily enters into fixed-fee contracts whereby its customers are required to pay the monthly fee even during periods of limited or disrupted throughput. Services are generally billed monthly, one month in advance of the commencement of the service month, except for certain customers who are billed at the beginning of the service month, and payment is generally due 30 days after receipt of the invoice. Amounts invoiced in advance are recorded as deferred revenue until earned, at which time they are recognized as revenue. The amount of consideration USAC receives and revenue it recognizes is based upon the fixed fee rate stated in each service contract.

Variable consideration exists in select contracts when billing rates vary based on actual equipment availability or volume of total installed horsepower.

USAC's contracts with customers may include multiple performance obligations. For such arrangements, USAC allocates revenues to each performance obligation based on its relative standalone service fee. USAC generally determine standalone service fees based on the service fees charged to customers or using expected cost plus margin.

The majority of USAC's service performance obligations are satisfied over time as services are rendered at selected customer locations on a monthly basis and based upon specific performance criteria identified in the applicable contract. The monthly service for each location is substantially the same service month to month and is promised consecutively over the service contract term. USAC measures progress and performance of the service consistently using a straight-line, time-based method as each month passes, because its performance obligations are satisfied evenly over the contract term as the customer simultaneously receives and consumes the benefits provided by its service. If variable consideration exists, it is allocated to the distinct monthly service within the series to which such variable consideration relates. USAC has elected to apply the invoicing practical expedient to recognize revenue for such variable consideration, as the invoice corresponds directly to the value transferred to the customer based on its performance completed to date.

There are typically no material obligations for returns or refunds. USAC's standard contracts do not usually include material non-cash consideration.

USAC's retail parts and services revenue

USAC's retail parts and service revenue is earned primarily on freight and crane charges that are directly reimbursable by USAC's customers and maintenance work on units at its customers' locations that are outside the scope of its core maintenance activities. Revenue from retail parts and services is recognized at the point in time the part is transferred or service is provided and control is transferred to the customer. At such time, the customer has the ability to direct the use of the benefits of such part or service after USAC has performed its services. USAC bills upon completion of the service or transfer of the parts, and payment is generally due 30 days after receipt of the invoice. The amount of consideration USAC receives and revenue it recognizes is based upon the invoice amount. There are typically no material obligations for returns, refunds, or warranties. USAC's standard contracts do not usually include material variable or non-cash consideration.

All other revenue

Our all other segment primarily includes our compression equipment business which provides full-service compression design and manufacturing services for the oil and gas industry. It also includes 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 end-user coal handling facilities. There were no material changes to the manner in which revenues within this segment are recorded under the new standard.

Contract Balances with Customers

The Partnership satisfies its obligations by transferring goods or services in exchange for consideration from customers. The timing of performance may differ from the timing the associated consideration is paid to or received from the customer, thus resulting in the recognition of a contract asset or a contract liability.

The Partnership recognizes a contract asset when making upfront consideration payments to certain customers or when providing services to customers prior to the time at which the Partnership is contractually allowed to bill for such services.

The Partnership recognizes a contract liability if the customer's payment of consideration precedes the Partnership's fulfillment of the performance obligations. Certain contracts contain provisions requiring customers to pay a fixed fee for a right to use our assets, but allows customers to apply such fees against services to be provided at a future point in time. These amounts are reflected as deferred revenue until the customer applies the deficiency fees to services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints. Additionally, Sunoco LP maintains some franchise agreements requiring dealers to make one-time upfront payments for long term license agreements. Sunoco LP recognizes a contract liability when the upfront payment is received and recognizes revenue over the term of the license. As of December 31, 2018, the Partnership had $405 million in deferred revenues representing the current value of our future performance obligations.

The amount of revenue recognized for the year ended December 31, 2018 that was included in the deferred revenue liability balance as of January 1, 2018 was $85 million.

The balances of receivables from contracts with customers listed in the table below include both current trade receivables and long-term receivables, net of allowance for doubtful accounts. The allowance for receivables represents Sunoco LP's best estimate of the probable losses associated with potential customer defaults. Sunoco LP determines the allowance based on historical experience and on a specific identification basis.

The opening and closing balances of Sunoco LP's contract assets and contract liabilities are as follows:

	Balance at January 1, 2018	Balance at December 31, 2018	Increase
Contract Balances			
Contract asset	$ 51	$ 75	$ 24
Accounts receivable from contracts with customers	445	347	(98)
Contract liability	1	1	—

Performance Obligations

At contract inception, the Partnership assesses the goods and services promised in its contracts with customers and identifies a performance obligation for each promise to transfer a good or service (or bundle of goods or services) that is distinct. To identify the performance obligations, the Partnership considers all the goods or services promised in the contract, whether explicitly stated or implied based on customary business practices. For a contract that has more than one performance obligation, the Partnership allocates the total contract consideration it expects to be entitled to, to each distinct performance obligation based on a standalone-selling price basis. Revenue is recognized when (or as) the performance obligations are satisfied, that is, when the customer obtains control of the good or service. Certain of our contracts contain variable components, which, when combined with the fixed component are considered a single performance obligation. For these types of contracts, only the fixed component of the contracts are included in the table below.

Sunoco LP distributes fuel under long-term contracts to branded distributors, branded and unbranded third party dealers, and branded and unbranded retail fuel outlets. Sunoco LP branded supply contracts with distributors generally have both time and volume commitments that establish contract duration. These contracts have an initial term of approximately nine years, with an estimated, volume-weighted term remaining of approximately four years.

As part of the asset purchase agreement with 7-Eleven, Sunoco LP and 7-Eleven and SEI Fuel (collectively, the "Distributor") have entered into a 15-year take-or-pay fuel supply agreement in which the Distributor is required to purchase a volume of fuel that provides Sunoco LP a minimum amount of gross profit annually. Sunoco LP expects to recognize this revenue in accordance with the contract as Sunoco LP transfers control of the product to the customer. However, in case of annual shortfall Sunoco LP will recognize the amount payable by the Distributor at the sooner of the time at which the Distributor makes up the shortfall or becomes contractually or operationally unable to do so. The transaction price of the contract is variable in nature, fluctuating based on market conditions. The Partnership has elected to take the practical expedient not to estimate the amount of variable consideration allocated to wholly unsatisfied performance obligations.

In some contractual arrangements, Sunoco LP grants dealers a franchise license to operate Sunoco LP's retail stores over the life of a franchise agreement. In return for the grant of the retail store license, the dealer makes a one-time nonrefundable franchise fee payment to Sunoco LP plus sales based royalties payable to Sunoco LP at a contractual rate during the period of the franchise agreement. Under the requirements of ASC Topic 606, the franchise license is deemed to be a symbolic license for which recognition of revenue over time is the most appropriate measure of progress toward complete satisfaction of the performance obligation. Revenue from this symbolic license is recognized evenly over the life of the franchise agreement.

As of December 31, 2018, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations is $42.35 billion and the Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	Years Ending December 31,				
	2019	2020	2021	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of December 31, 2018	$ 5,529	$ 4,955	$ 4,413	$ 27,452	$ 42,349

Costs to Obtain or Fulfill a Contract

Sunoco LP recognizes an asset from the costs incurred to obtain a contract (e.g. sales commissions) only if it expects to recover those costs. On the other hand, the costs to fulfill a contract are capitalized if the costs are specifically identifiable to a contract, would result in enhancing resources that will be used in satisfying performance obligations in future and are expected to be recovered. These capitalized costs are recorded as a part of Other Assets and are amortized on a systematic basis consistent with the pattern of transfer of the goods or services to which such costs relate. The amount of amortization expense that the Sunoco LP recognized for the year ended December 31, 2018 was $14 million. Sunoco LP has also made a policy election of expensing the costs to obtain a contract, as and when they are incurred, in cases where the expected amortization period is one year or less.

Practical Expedients Utilized by the Partnership

The Partnership elected the following practical expedients in accordance with Topic 606:

- *Right to invoice:* The Partnership elected to utilize an output method to recognize revenue that is based on the amount to which the Partnership has a right to invoice a customer for services performed to date, if that amount corresponds directly with the value provided to the customer for the related performance or its obligation completed to date. As such, the Partnership recognized revenue in the amount to which it had the right to invoice customers.
- *Significant financing component:* The Partnership elected not to adjust the promised amount of consideration for the effects of significant financing component if the Partnership expects, at contract inception, that the period between the transfer of a promised good or service to a customer and when the customer pays for that good or service will be one year or less.

- *Unearned variable consideration:* The Partnership elected to only disclose the unearned fixed consideration associated with unsatisfied performance obligations related to our various customer contracts which contain both fixed and variable components.
- *Incremental costs of obtaining a contract:* The Partnership generally expenses sales commissions when incurred because the amortization period would have been less than one year. We record these costs within general and administrative expenses. The Partnership elected to expense the incremental costs of obtaining a contract when the amortization period for such contracts would have been one year or less.
- *Shipping and handling costs:* The Partnership elected to account for shipping and handling activities that occur after the customer has obtained control of a good as fulfillment activities (i.e., an expense) rather than as a promised service.
- *Measurement of transaction price:* The Partnership has elected to exclude from the measurement of transaction price all taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Partnership from a customer (i.e., sales tax, value added tax, etc.).
- *Variable consideration of wholly unsatisfied performance obligations:* The Partnership has elected to exclude the estimate of variable consideration to the allocation of wholly unsatisfied performance obligations.

13. 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 utilize swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

We use futures and swaps to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales. 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, 2018		December 31, 2017	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	468	2019	1,078	2018
Basis Swaps IFERC/NYMEX[(1)]	16,845	2019-2020	48,510	2018-2020
Options – Puts	10,000	2019	13,000	2018
Power (Megawatt):				
Forwards	3,141,520	2019	435,960	2018-2019
Futures	56,656	2019-2021	(25,760)	2018
Options – Puts	18,400	2019	(153,600)	2018
Options – Calls	284,800	2019	137,600	2018
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(30,228)	2019-2021	4,650	2018-2020
Swing Swaps IFERC	54,158	2019-2020	87,253	2018-2019
Fixed Swaps/Futures	(1,068)	2019-2021	(4,390)	2018-2019
Forward Physical Contracts	(123,254)	2019-2020	(145,105)	2018-2020
NGL (MBbls) – Forwards/Swaps	(2,135)	2019	(2,493)	2018-2019
Crude (MBbls) – Forwards/Swaps	20,888	2019	9,237	2018-2019
Refined Products (MBbls) – Futures	(1,403)	2019	(3,901)	2018-2019
Corn (thousand bushels)	(1,920)	2019	1,870	2018
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(17,445)	2019	(39,770)	2018
Fixed Swaps/Futures	(17,445)	2019	(39,770)	2018
Hedged Item – Inventory	17,445	2019	39,770	2018

(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 are designated as hedges for accounting purposes:

		Notional Amount Outstanding	
Term	Type [1]	December 31, 2018	December 31, 2017
July 2018 [2]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	$ —	$ 300
July 2019 [2]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	400	300
July 2020 [2]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	400
July 2021 [2]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	400	—
December 2018	Pay a floating rate and receive a fixed rate of 1.53%	—	1,200
March 2019	Pay a floating rate 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 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 industrial end-users, 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 with 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, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ —	$ 14	$ (13)	$ (2)
	—	14	(13)	(2)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	402	262	(397)	(281)
Commodity derivatives	158	45	(173)	(58)
Interest rate derivatives	—	—	(163)	(219)
	560	307	(733)	(558)
Total derivatives	$ 560	$ 321	$ (746)	$ (560)

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, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (163)	$ (219)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	158	45	(173)	(58)
Broker cleared derivative contracts	Other current assets (liabilities)	402	276	(410)	(283)
		560	321	(746)	(560)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(47)	(21)	47	21
Counterparty netting	Other current assets (liabilities)	(397)	(263)	397	263
Total net derivatives		$ 116	$ 37	$ (302)	$ (276)

We disclose the non-exchange traded financial derivative instruments as derivative 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) 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,		
		2018	2017	2016
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ (3)	$ 26	$ 14

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2018	2017	2016
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$ 32	$ 31	$ (35)
Commodity derivatives – Non-trading	Cost of products sold	(102)	5	(177)
Interest rate derivatives	Gains (losses) on interest rate derivatives	47	(37)	(12)
Embedded derivatives	Other, net	—	1	4
Total		$ (23)	$ —	$ (220)

14. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all eligible employees, including those of ETO, Lake Charles LNG, Sunoco LP and USAC. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries made matching contributions of $62 million, $59 million and $65 million to these 401(k) savings plans for the years ended December 31, 2018, 2017 and 2016, respectively.

Pension and Other Postretirement Benefit Plans

Panhandle

Postretirement benefits expense for the years ended December 31, 2018, 2017, and 2016 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.

Effective January 1, 2018, the plan was amended to extend coverage to a new closed group of former employees based on certain criteria.

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, 2018			December 31, 2017		
	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	$ 1	$ 47	$ 156	$ 18	$ 51	$ 166
Service cost	—	—	1	—	—	—
Interest cost	—	1	5	1	1	4
Amendments	—	—	60	—	—	7
Benefits paid, net	—	(7)	(17)	(2)	(6)	(20)
Actuarial (gain) loss and other	—	(4)	(7)	2	1	(1)
Settlements	—	—	—	(18)	—	—
Benefit obligation at end of period	1	37	198	1	47	156
Change in plan assets:						
Fair value of plan assets at beginning of period	1	—	257	12	—	256
Return on plan assets and other	—	—	(8)	3	—	11
Employer contributions	—	—	9	6	—	10
Benefits paid, net	—	—	(17)	(2)	—	(20)
Settlements	—	—	—	(18)	—	—
Fair value of plan assets at end of period	1	—	241	1	—	257
Amount underfunded (overfunded) at end of period	$ —	$ 37	$ (43)	$ —	$ 47	$ (101)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$ —	$ —	$ 68	$ —	$ —	$ 127
Current liabilities	—	(6)	(2)	—	(8)	(2)
Non-current liabilities	—	(31)	(23)	—	(39)	(24)
	$ —	$ (37)	$ 43	$ —	$ (47)	$ 101
Amounts recognized in accumulated other comprehensive income (loss) (pre-tax basis) consist of:						
Net actuarial gain (loss)	$ —	$ 1	$ (7)	$ —	$ 5	$ (18)
Prior service cost	—	—	66	—	—	21
	$ —	$ 1	$ 59	$ —	$ 5	$ 3

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

	December 31, 2018			December 31, 2017		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$ —	$ 37	N/A	$ 1	$ 47	N/A
Accumulated benefit obligation	1	37	$ 198	1	47	$ 156
Fair value of plan assets	1	—	241	1	—	257

Components of Net Periodic Benefit Cost

	December 31, 2018		December 31, 2017	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$ —	$ 1	$ —	$ —
Interest cost	1	5	2	4
Expected return on plan assets	—	(10)	—	(9)
Prior service cost amortization	—	16	—	2
Net periodic benefit cost	$ 1	$ 12	$ 2	$ (3)

Assumptions

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

	December 31, 2018		December 31, 2017	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.02%	3.40%	3.27%	2.34%
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, 2018		December 31, 2017	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.52%	3.51%	3.52%	3.10%
Expected return on assets:				
Tax exempt accounts	3.26%	6.63%	3.50%	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's and Sunoco, Inc.'s other postretirement benefit plans are shown in the table below:

	December 31,	
	2018	2017
Health care cost trend rate	7.15%	7.20%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.82%	4.99%
Year that the rate reaches the ultimate trend rate	2024	2023

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%.

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, 2018		
	Fair Value Total	Level 1	Level 2	Level 3
Mutual funds [1]	$ 1	$ 1	$ —	$ —

[1] Comprised of 100% equities as of December 31, 2018.

		Fair Value Measurements at December 31, 2017		
	Fair Value Total	Level 1	Level 2	Level 3
Mutual funds [1]	$ 1	$ 1	$ —	$ —

[1] Comprised of 100% equities as of December 31, 2017.

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

		Fair Value Measurements at December 31, 2018		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 20	$ 20	$ —	$ —
Mutual funds[1]	144	144	—	—
Fixed income securities	77	—	77	—
Total	$ 241	$ 164	$ 77	$ —

[1] Primarily comprised of approximately 53% equities, 46% fixed income securities and 1% cash as of December 31, 2018.

	Fair Value Total		Fair Value Measurements at December 31, 2017					
			Level 1		Level 2		Level 3	
Asset category:								
Cash and cash equivalents	$	33	$	33	$	—	$	—
Mutual funds[1]		154		154		—		—
Fixed income securities		70		—		70		—
Total	$	257	$	187	$	70	$	—

(1) Primarily comprised of approximately 38% equities, 61% fixed income securities and 2% cash as of December 31, 2017.

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 $6 million to pension plans and $10 million to other postretirement plans in 2019. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Panhandle's and Sunoco, Inc.'s estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

Years	Pension Benefits - Unfunded Plans [1]		Other Postretirement Benefits (Gross, Before Medicare Part D)	
2019	$	6	$	20
2020		6		20
2021		5		20
2022		4		18
2023		4		17
2024 – 2028		12		66

(1) Expected benefit payments of funded pension plans are less than $1 million for the next ten years.

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

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

15. RELATED PARTY TRANSACTIONS:

In June 2017, the Partnership acquired all of the publicly held PennTex common units through a tender offer and exercise of a limited call right, as further discussed in Note 8.

ET previously paid ETO to provide services on its behalf and on behalf of other subsidiaries of ET, which included the reimbursement of various operating and general and administrative expenses incurred by ETO on behalf of ET and its subsidiaries. These agreements expired in 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,		
	2018	2017	2016
Affiliated revenues	$ 431	$ 303	$ 221

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

	December 31,	
	2018	2017
Accounts receivable from related companies:		
FGT	25	11
Phillips 66	42	20
Other	44	22
Total accounts receivable from related companies	$ 111	$ 53

As of December 31, 2018 and 2017, accounts payable with related companies in the Partnership's consolidated balance sheets totaled $59 million and $31 million, respectively.

16. REPORTABLE SEGMENTS:

As a result of the Energy Transfer Merger in October 2018, our reportable segments were reevaluated and currently reflect the following segments, which conduct their business primarily in the United States:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;
- crude oil transportation and services;
- investment in Sunoco LP;
- investment in USAC; and
- all other.

The investment in USAC segment reflects the results of USAC beginning April 2018, the date that the Partnership obtained control of USAC.

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 investment in Sunoco LP segment are primarily reflected in refined product sales. Revenues from our investment in USAC segment are primarily reflected in gathering, transportation and other fees. Revenues from our all other segment are primarily reflected in natural gas 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, 2018	2017	2016
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$ 3,428	$ 2,891	$ 2,155
Intersegment revenues	309	192	458
	3,737	3,083	2,613
Interstate transportation and storage:			
Revenues from external customers	1,664	1,112	1,143
Intersegment revenues	18	19	23
	1,682	1,131	1,166
Midstream:			
Revenues from external customers	2,090	2,510	2,342
Intersegment revenues	5,432	4,433	2,837
	7,522	6,943	5,179
NGL and refined products transportation and services:			
Revenues from external customers	10,119	7,885	5,764
Intersegment revenues	1,004	763	645
	11,123	8,648	6,409
Crude oil transportation and services:			
Revenues from external customers	17,236	11,672	7,539
Intersegment revenues	96	31	—
	17,332	11,703	7,539
Investment in Sunoco LP:			
Revenues from external customers	16,982	11,713	9,977
Intersegment revenues	12	10	9
	16,994	11,723	9,986
Investment in USAC:			
Revenues from external customers	495	—	—
Intersegment revenues	13	—	—
	508	—	—
All other:			
Revenues from external customers	2,073	2,740	2,872
Intersegment revenues	155	161	400
	2,228	2,901	3,272
Eliminations	(7,039)	(5,609)	(4,372)
Total revenues	$ 54,087	$ 40,523	$ 31,792

	Years Ended December 31,		
	2018	2017	2016
Cost of products sold:			
Intrastate transportation and storage	$ 2,665	$ 2,327	$ 1,897
Midstream	5,145	4,761	3,381
NGL and refined products transportation and services	8,462	6,508	4,553
Crude oil transportation and services	14,439	9,826	6,416
Investment in Sunoco LP	15,872	10,615	8,830
Investment in USAC	67	—	—
All other	2,006	2,509	2,942
Eliminations	(6,998)	(5,580)	(4,326)
Total cost of products sold	$ 41,658	$ 30,966	$ 23,693

	Years Ended December 31,		
	2018	2017	2016
Depreciation, depletion and amortization:			
Intrastate transportation and storage	$ 169	$ 147	$ 144
Interstate transportation and storage	334	254	246
Midstream	1,006	954	840
NGL and refined products transportation and services	466	401	355
Crude oil transportation and services	445	402	251
Investment in Sunoco LP	167	169	176
Investment in USAC	169	—	—
All other	103	227	204
Total depreciation, depletion and amortization	$ 2,859	$ 2,554	$ 2,216

	Years Ended December 31,		
	2018	2017	2016
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ 19	$ (156)	$ 35
Interstate transportation and storage	227	236	193
Midstream	26	20	19
NGL and refined products transportation and services	64	33	41
Crude oil transportation and services	6	4	(4)
All other	2	7	(14)
Total equity in earnings of unconsolidated affiliates	$ 344	$ 144	$ 270

	Years Ended December 31,		
	2018	2017	2016
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 927	$ 626	$ 613
Interstate transportation and storage	1,680	1,274	1,297
Midstream	1,627	1,481	1,133
NGL and refined products transportation and services	1,979	1,641	1,496
Crude oil transportation and services	2,330	1,379	834
Investment in Sunoco LP	638	732	665
Investment in USAC	289	—	—
All Other	40	187	97
Total Segment Adjusted EBITDA	9,510	7,320	6,135
Depreciation, depletion and amortization	(2,859)	(2,554)	(2,216)
Interest expense, net	(2,055)	(1,922)	(1,804)
Gains on acquisitions	—	—	83
Impairment losses	(431)	(1,039)	(1,040)
Gains (losses) on interest rate derivatives	47	(37)	(12)
Non-cash compensation expense	(105)	(99)	(70)
Unrealized gains (losses) on commodity risk management activities	(11)	59	(136)
Inventory valuation adjustments	(85)	24	97
Losses on extinguishments of debt	(112)	(89)	—
Adjusted EBITDA related to unconsolidated affiliates	(655)	(716)	(675)
Equity in earnings of unconsolidated affiliates	344	144	270
Impairment of investments in unconsolidated affiliates	—	(313)	(308)
Adjusted EBITDA related to discontinued operations	25	(223)	(199)
Other, net	21	155	79
Income from continuing operations before income tax (expense) benefit	3,634	710	204
Income tax (expense) benefit from continuing operations	(4)	1,833	258
Income from continuing operations	3,630	2,543	462
Loss from discontinued operations, net of income taxes	(265)	(177)	(462)
Net income	$ 3,365	$ 2,366	$ —

	December 31,		
	2018	2017	2016
Total assets:			
Intrastate transportation and storage	$ 6,365	$ 5,020	$ 5,174
Interstate transportation and storage	15,081	15,316	12,492
Midstream	19,745	20,004	17,873
NGL and refined products transportation and services	19,227	17,600	14,074
Crude oil transportation and services	17,062	17,730	15,908
Investment in Sunoco LP	4,879	8,344	8,701
Investment in USAC	3,775	—	—
All other and eliminations	2,112	2,232	4,703
Total	$ 88,246	$ 86,246	$ 78,925

	Years Ended December 31,		
	2018	2017	2016
Additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (capital expenditures related to the Partnership's proportionate ownership on an accrual basis):			
Intrastate transportation and storage	$ 344	$ 175	$ 76
Interstate transportation and storage	812	728	280
Midstream	1,161	1,308	1,255
NGL and refined products transportation and services	2,381	2,971	2,198
Crude oil transportation and services	474	453	1,841
Investment in Sunoco LP	103	103	119
Investment in USAC	205	—	—
All other	150	268	160
Total additions to property, plant and equipment excluding acquisitions, net of contributions in aid of construction costs (accrual basis)	$ 5,630	$ 6,006	$ 5,929

	December 31,		
	2018	2017	2016
Advances to and investments in affiliates:			
Intrastate transportation and storage	$ 83	$ 85	$ 387
Interstate transportation and storage	2,070	2,118	2,149
Midstream	124	126	111
NGL and refined products transportation and services	243	234	235
Crude oil transportation and services	28	22	18
All other	94	120	140
Total	$ 2,642	$ 2,705	$ 3,040

17. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. Earnings per unit are computed on a stand-alone basis for each quarter and total year.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2018:					
Revenues	$ 11,882	$ 14,118	$ 14,514	$ 13,573	$ 54,087
Operating income	1,100	1,126	1,703	1,419	5,348
Income from continuing operations	726	659	1,393	852	3,630
Net income	489	633	1,391	852	3,365
Limited Partners' interest in net income	341	330	370	617	1,658
Income from continuing operations per limited partner unit:					
Basic	$ 0.32	$ 0.30	$ 0.32	$ 0.26	$ 1.17
Diluted	$ 0.32	$ 0.30	$ 0.32	$ 0.26	$ 1.16
Net income per limited partner unit:					
Basic	$ 0.31	$ 0.30	$ 0.32	$ 0.26	$ 1.16
Diluted	$ 0.31	$ 0.30	$ 0.32	$ 0.26	$ 1.15

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2017:					
Revenues	$ 9,661	$ 9,427	$ 9,984	$ 11,451	$ 40,523
Operating income	758	743	931	289	2,721
Income from continuing operations	330	314	741	1,158	2,543
Net income	319	121	758	1,168	2,366
Limited Partners' interest in net income	232	204	240	239	915
Income from continuing operations per limited partner unit:					
Basic	$ 0.22	$ 0.20	$ 0.22	$ 0.22	$ 0.86
Diluted	$ 0.21	$ 0.19	$ 0.22	$ 0.22	$ 0.84
Net income per limited partner unit:					
Basic	$ 0.22	$ 0.19	$ 0.22	$ 0.22	$ 0.85
Diluted	$ 0.21	$ 0.18	$ 0.22	$ 0.22	$ 0.83

The three months ended December 31, 2018 and 2017 reflected the recognition of impairment losses of $431 million and $1.04 billion, respectively. Impairment losses in 2018 were primarily related to our midstream segment. Impairment losses in 2017 were primarily related to our interstate transportation and storage segment, NGL and refined products segment, all other segment as well as investment in Sunoco LP segment. The three months ended December 31, 2017 also reflected the recognition of a non-cash impairment of our investments in subsidiaries of $313 million in our interstate transportation and storage segment.

18. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of the Parent Company, which are included to provide additional information with respect to the Parent Company's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS

	December 31, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 1
Accounts receivable from related companies	65	65
Other current assets	1	1
Total current assets	68	67
PROPERTY, PLANT AND EQUIPMENT, net	23	27
ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES	26,581	6,082
GOODWILL	—	9
OTHER NON-CURRENT ASSETS, net	—	8
Total assets	$ 26,672	$ 6,193
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 2	$ —
Accounts payable to related companies	65	—
Interest payable	76	66
Accrued and other current liabilities	3	4
Total current liabilities	146	70
LONG-TERM DEBT, less current maturities	5,519	6,700
NOTE PAYABLE TO AFFILIATE	445	617
OTHER NON-CURRENT LIABILITIES	3	2
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL (DEFICIT):		
General Partner	(5)	(3)
Limited Partners:		
Common Unitholders (2,619,368,605 and 1,079,145,561 units authorized, issued and outstanding as of December 31, 2018 and 2017, respectively)	20,606	(1,643)
Series A Convertible Preferred Units (329,295,770 units authorized, issued and outstanding as of December 31, 2017)	—	450
Accumulated other comprehensive income (loss)	(42)	—
Total partners' capital (deficit)	20,559	(1,196)
Total liabilities and partners' capital (deficit)	$ 26,672	$ 6,193

STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2018	2017	2016
DEPRECIATION, DEPLETION AND AMORTIZATION	$ (4)	$ —	$ —
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	(37)	(31)	(185)
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(346)	(347)	(327)
Interest expense - affiliates	(8)	—	—
Equity in earnings of unconsolidated affiliates	2,092	1,381	1,511
Loss on extinguishment of debt	—	(47)	—
Other, net	(3)	(2)	(4)
INCOME BEFORE INCOME TAX EXPENSE	1,694	954	995
Income tax expense	—	—	—
NET INCOME	1,694	954	995
General Partner’s interest in net income	3	2	3
Convertible Unitholders’ interest in income	33	37	9
Limited Partners’ interest in net income	$ 1,658	$ 915	$ 983

STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2018	2017	2016
OPERATING ACTIVITIES	$ 2,245	$ 831	$ 918
INVESTING ACTIVITIES:			
Contributions to unconsolidated affiliates	(250)	(861)	(70)
Capital expenditures	—	(1)	(16)
Contributions in aid of construction costs	—	7	—
Sunoco LP Series A Preferred Units redemption	303	—	—
Net cash provided by (used in) investing activities	53	(855)	(86)
FINANCING ACTIVITIES:			
Proceeds from borrowings	463	2,219	225
Principal payments on debt	(1,651)	(1,881)	(210)
Distributions to partners	(1,684)	(1,010)	(1,022)
Proceeds from affiliate	575	174	176
Common Units issued for cash	—	568	—
Debt issuance costs	—	(47)	—
Net cash (used in) provided by financing activities	(2,297)	23	(831)
Increase (decrease) in cash and cash equivalents	1	(1)	1
Cash and cash equivalents, beginning of period	1	2	1
Cash and cash equivalents, end of period	$ 2	$ 1	$ 2