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, 2019

or

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

Commission file number 1-31219

ENERGY TRANSFER OPERATING, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**73-1493906**
(state or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)
Registrant's telephone number, including area code: **(214) 981-0700**

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETPprC**	**New York Stock Exchange**
7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETPprD**	**New York Stock Exchange**
7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETPprE**	**New York Stock Exchange**
7.500% Senior Notes due 2020	**ETP 20**	**New York Stock Exchange**
4.250% Senior Notes due 2023	**ETP 23**	**New York Stock Exchange**
5.875% Senior Notes due 2024	**ETP 24**	**New York Stock Exchange**
5.500% Senior Notes due 2027	**ETP 27**	**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 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 ☒

DOCUMENTS INCORPORATED BY REFERENCE

None

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Forward-Looking Statements

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

Definitions

The following is a list of certain acronyms and terms used throughout this document:

/d	per day
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 used
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
CDM	CDM Resource Management LLC and CDM Environmental & Technical Services LLC, collectively
Citrus	Citrus, LLC
Dakota Access	Dakota Access, LLC, a less than wholly-owned subsidiary of ETO
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
ET	Energy Transfer LP, the parent company of ETO
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company and is a wholly-owned subsidiary of ETO
ETC Sunoco	ETC Sunoco Holdings LLC (formerly, Sunoco Inc.), a wholly-owned subsidiary of ETO
ETC Tiger	ETC Tiger Pipeline, LLC, a wholly-owned subsidiary of ETO
ETCO	Energy Transfer Crude Oil Company, LLC, a less than wholly-owned subsidiary of ETO
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETO

ETP Holdco	ETP Holdco Corporation, a wholly owned subsidiary of ETO
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
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC, a wholly-owned subsidiary of Citrus
GAAP	accounting principles generally accepted in the United States of America
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of ETO
HFOTCO	Houston Fuel Oil Terminal Company, a wholly-owned subsidiary of ETO, which owns the Houston Terminal
HPC	RIGS Haynesville Partnership Co., a wholly-owned subsidiary of ETO
IDRs	incentive distribution rights
KMI	Kinder Morgan Inc.
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a wholly-owned subsidiary of ETO
LCL	Lake Charles LNG Export Company, LLC, a wholly-owned subsidiary of ETO
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lone Star	Lone Star NGL LLC, a wholly-owned subsidiary of ETO
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
Mi Vida JV	Mi Vida JV LLC
Mid-Valley	Mid-Valley Pipeline Company, a wholly-owned subsidiary of ETO
MMBls	million barrels
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
ORS	Ohio River System LLC, a less than wholly-owned subsidiary of ETO
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries, wholly-owned by ETO
PCBs	polychlorinated biphenyls
PennTex	PennTex Midstream Partners, LP, acquired by ETO during 2016-2017 and now a wholly-owned subsidiary named ETC PennTex LLC
PEP	Permian Express Partners LLC, a less than wholly-owned subsidiary of ETO

PES	Philadelphia Energy Solutions Refining and Marketing LLC, non-controlling interest owned by ETO
Phillips 66	Phillips 66 Partners LP
PHMSA	Pipeline Hazardous Materials Safety Administration
Preferred Unitholders	Unitholders of the Series A Preferred Units, Series B Preferred Units, Series C Preferred Units, Series D Preferred Units, Series E Preferred Units, Series F Preferred Units and Series G Preferred Units, collectively
Ranch JV	Ranch Westex JV LLC
Regency	Regency Energy Partners LP, a wholly-owned subsidiary of ETO
Retail Holdings	ETP Retail Holdings, LLC, a wholly-owned subsidiary of ETO
RIGS	Regency Intrastate Gas System, a wholly-owned subsidiary of ETO
Rover	Rover Pipeline LLC, a less than wholly-owned subsidiary of ETO
Sea Robin	Sea Robin Pipeline Company, LLC, a wholly-owned subsidiary of Panhandle
SEC	Securities and Exchange Commission
SemGroup	SemGroup Corporation
Series A Preferred Units	6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series B Preferred Units	6.625% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series C Preferred Units	7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series D Preferred Units	7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series E Preferred Units	7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series F Preferred Units	6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series G Preferred Units	7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Shell	Royal Dutch Shell plc
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas Storage Company)
SPLP	Sunoco Pipeline L.P., a wholly-owned subsidiary of ETO
Sunoco Logistics	Sunoco Logistics Partners L.P., a wholly-owned subsidiary of ETO
Sunoco (R&M)	Sunoco (R&M), LLC
Transwestern	Transwestern Pipeline Company, LLC, a wholly-owned subsidiary of ETO
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a wholly-owned subsidiary of Panhandle
Unitholders	Preferred Unitholders and our common unitholder (Energy Transfer LP), collectively
USAC	USA Compression Partners, LP, a wholly-owned subsidiary of ETO

Adjusted EBITDA is a term used throughout this document, which we define as total Partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

PART I

ITEM 1. BUSINESS

Overview

We (Energy Transfer Operating, L.P., a Delaware limited partnership, "ETO" or the "Partnership") are a consolidated subsidiary of Energy Transfer LP ("ET"). In October 2018, ET completed the merger of ETO with a wholly-owned subsidiary of ET in a unit-for-unit exchange (the "Energy Transfer Merger"), as discussed further below, at which time the Partnership changed its name from Energy Transfer Partners, L.P. to Energy Transfer Operating, L.P.

We are managed by our general partner, Energy Transfer Partners GP, L.P. (our "General Partner" or "ETP GP"), and ETP GP is managed by its general partner, Energy Transfer Partners, L.L.C. ("ETP LLC"), which is wholly owned by ET. The primary activities in which we are engaged, all of which are in the United States, 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.

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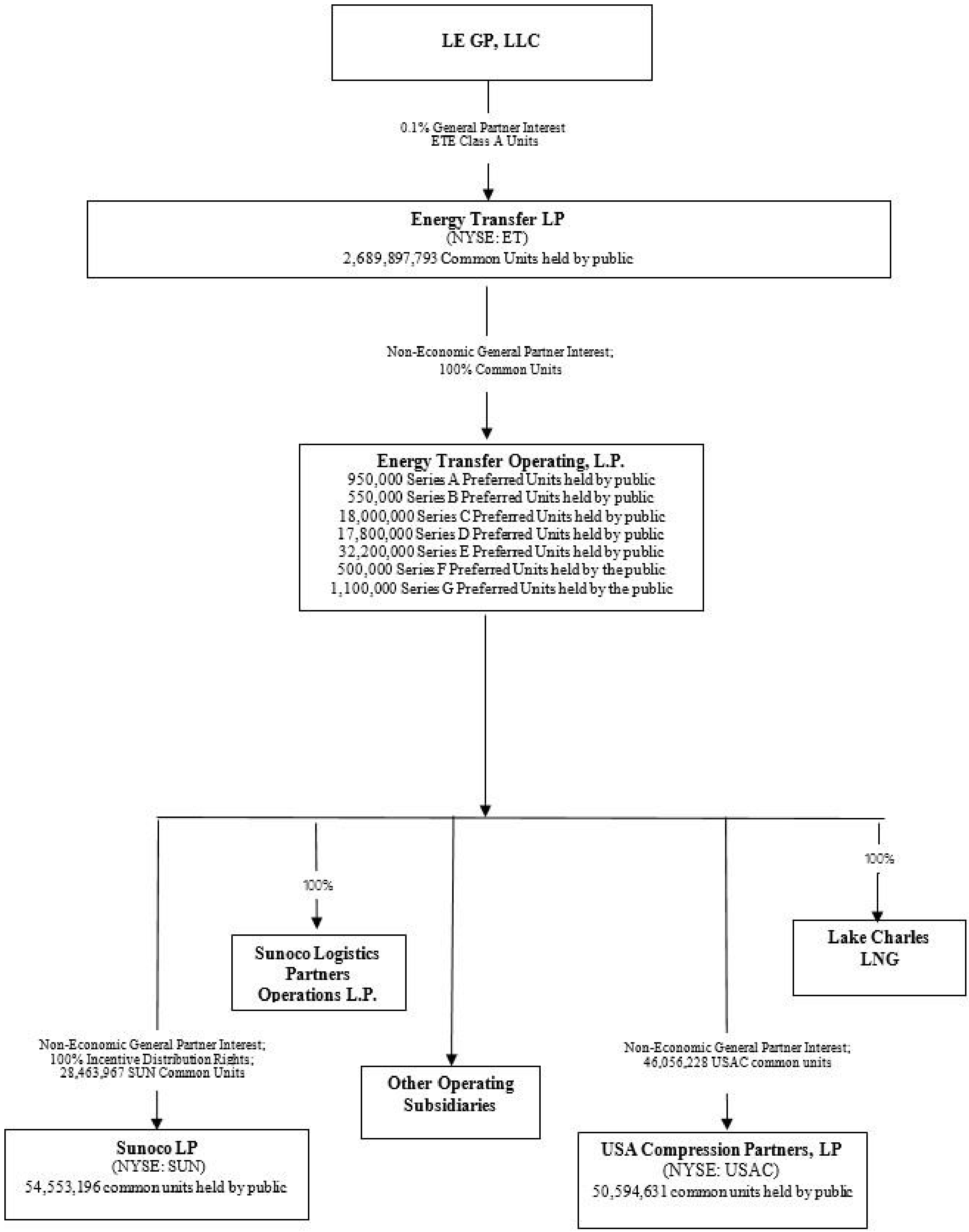
The following chart summarizes our organizational structure as of February 14, 2020. For simplicity, certain immaterial entities and ownership interests have not been depicted.



Unless the context requires otherwise, the Partnership and its subsidiaries are collectively referred to in this report as "we," "us," "ETO," "Energy Transfer" or "the Partnership."

Significant Achievements in 2019 and Beyond

Strategic Transactions Related to the Partnership

- In December 2019, ET completed its acquisition of Tulsa-based SemGroup Corporation in a unit and cash transaction. During the first quarter of 2020, certain of the operating assets of SemGroup were contributed to ETO, and as such, the segment and asset overviews below include those contributed SemGroup assets.

Significant Organic Growth Projects

Our significant announced organic growth projects in 2019 included the following, as discussed in more detail herein:

- In December 2019, ET announced a comprehensive commercial tender package which was issued to engineering, procurement and construction contractors to submit final bids for the proposed Lake Charles LNG liquefaction project being developed with Shell US LNG, LLC. The project would modify ETO's existing LNG import facility located in Lake Charles, Louisiana to add LNG liquefaction capacity of 16.45 million tonnes per annum for expert to global markets. The commercial bids are expected to be received in the second quarter of 2020.

- In connection with the acquisition of SemGroup and to provide shippers with further access to markets along the Gulf Coast through the Houston Ship Channel, ET announced the construction of the Ted Collins pipeline, a 75-mile crude line that will connect Houston Terminal, which was recently acquired in the SemGroup acquisition, to the Nederland terminal. The pipeline is expected to be in service in 2021 and will have an initial capacity of 500 MBbls/d.

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 22 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 108-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 12,500 miles of interstate natural gas pipelines with approximately 10.7 Bcf/d of transportation capacity and another approximately 6,770 miles and 10.6 Bcf/d of transportation capacity through joint venture interests.

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. In December 2019, ET announced a comprehensive commercial tender package has been issued to engineering, procurement and construction contractors to submit final bids for the proposed Lake Charles LNG liquefaction project being developed with Shell US LNG, LLC. The project would modify ETO's existing LNG import facility to add LNG liquefaction capacity of 16.45 million tonnes per annum for expert to global markets. The commercial bids are expected to be received in the second quarter of 2020.

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 8.8 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, Oklahoma, Kansas 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 4,515 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 50 MMBbls; 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 13 MMBbls.

We are currently constructing a seventh fractionator, which went into operation in the first quarter of 2020, and an eighth fractionator, which we expect to be operational in the second quarter of 2021, at our Mont Belvieu facility. 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 8 MMBbls 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 3,265 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 MMBbls 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. The mix of products delivered through our refined products pipelines varies seasonally, with gasoline demand peaking during the summer months, and demand for heating oil and other distillate fuels peaking in the winter. 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.

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 (via pipeline and trucking), terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest, northwestern 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 10,770 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States. This segment includes equity ownership interests in four crude oil pipelines, the Bakken Pipeline system, Bayou Bridge Pipeline, White Cliffs Pipeline and Maurepas Pipeline. Our crude oil terminalling services operate with an aggregate storage capacity of approximately 64 MMBbls, including approximately 29 MMBbls at our Gulf Coast terminal in Nederland, Texas, approximately 18.2 MMBbls at our Gulf coast terminal on the Houston Ship Channel, approximately 7.6 MMBbls at our Cushing facility in Cushing, Oklahoma and approximately 3.2 MMBbls 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 Sunoco-branded motor fuel, supplying an extensive distribution network of approximately 5,474 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 natural gas 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 six 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, 2019, USAC had 3,682,968 horsepower in its fleet and 56,500 large horsepower on order for expected delivery during 2020.

All Other Segment

Our "All Other" segment includes the following:

- Our approximately 7.4% 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 the Partnership's reportable segments. Amounts, such as capacities, volumes and miles included in the descriptions below are approximate and are based on information currently available; such amounts are subject to change based on future events or additional information.

Intrastate Transportation and Storage

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

Description of Assets	Ownership Interest	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Storage Capacity (Bcf/d)
ET Fuel System	100%	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	2.9	—
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%	108	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 Maypearl Hub in Central Texas and the Carthage Hub in East Texas, the three major natural gas trading centers in Texas.

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

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

- The Oasis Pipeline is primarily a 36-inch natural gas pipeline. It has bi-directional capabilities with approximately 1.3 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 our 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 our processing plants and treating facilities on the Southeast Texas System when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

- The HPL System is an extensive network of intrastate natural gas pipelines, an underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from South Texas, the Gulf Coast of Texas, East Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City, Beaumont 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, Carthage 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, 2019, we had approximately 19.0 Bcf committed under fee-based arrangements with third parties and approximately 27.3 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 108-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. 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%	5,362	3.5	—
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	—
Stingray Pipeline	100%	302	0.4	—
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 Southwest Gas.

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

- Florida Gas Transmission Pipeline ("FGT") has mainline capacity of 3.5 Bcf/d and approximately 5,362 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 approximately 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 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, interconnecting with 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.
- Stingray Pipeline is an interstate natural gas pipeline system with related assets located in the western Gulf of Mexico and Johnson Bayou, Louisiana.

- 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.

In December 2019, ET announced a comprehensive commercial tender package which was issued to engineering, procurement and construction contractors to submit final bids for the proposed Lake Charles LNG liquefaction project being developed with Shell US LNG, LLC. The commercial bids are expected to be received in the second quarter of 2020.

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 the midstream segment:

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	2,740
Midcontinent Region	1,385
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 1.4 Bcf/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 2.4 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 and the STACK in central Oklahoma. 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 sixteen natural gas processing facilities (Mocane, Beaver, Antelope Hills, Woodall, Wheeler, Sunray, Hemphill, Phoenix, Hamlin, Spearman, Red Deer, Lefors, Cargray, Gray, Rose Valley, and Hopeton) with an aggregate capacity of approximately 1.4 Bcf/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 segment:

Description of Assets	Miles of Liquids Pipeline [2]	NGL Fractionation / Processing Capacity (MBbls/d)	Working Storage Capacity (MBbls)
Liquids Pipelines:			
Lone Star Express	535	—	—
West Texas Gateway Pipeline	512	—	—
Lone Star	1,617	—	—
Mariner East	670	—	—
Mariner South	97	—	—
Mariner West	395	—	—
White Cliffs Pipeline[3]	527	—	—
Other NGL Pipelines	162	—	—
Liquids Fractionation and Services Facilities:			
Mont Belvieu Facilities	182	790	50,000
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	6,000
Inkster	—	—	860
Refined Products Pipelines:			
Eastern region pipelines	957	—	—
Midcontinent region pipelines	349	—	—
Southwest region pipelines	876	—	—
Inland Pipeline	581	—	—
JC Nolan Pipeline	502	—	—
Refined Products Terminals:			
Eagle Point	—	—	7,000
Marcus Hook Industrial Complex	—	—	1,000
Marcus Hook Tank Farm	—	—	2,000
Marketing Terminals	—	—	8,000
JC Nolan Terminal	—	—	134

(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.

(3) The White Cliffs Pipeline consists of two parallel, 12-inch common carrier pipelines: one crude oil pipeline and one NGL pipeline.

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, with throughput capacity of approximately 500 MBbls/d, 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 and has a throughput capacity of approximately 240 MBbls/d.
- 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 East pipeline has a throughput capacity of approximately 345 MBbls/d.
- 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 and has a throughput capacity of approximately 200 MBbls/d.
- 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 and has a throughput capacity of approximately 50 MBbls/d.
- The White Cliffs NGL pipeline, which we have 51% ownership interest in and which was acquired by ET in the SemGroup acquisition and contributed to ETO in January 2020, transports NGLs produced in the DJ Basin to Cushing, where it interconnects with the Southern Hills Pipeline to move NGLs to Mont Belvieu, Texas and has a throughput capacity of approximately 40 MBbls/d.
- 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 approximately 50 MMBbls 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 was placed in service in the first quarter of 2020, and Fractionator VIII is currently under construction and is scheduled to be operational by the second quarter of 2021.
- 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 MMBbls 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 MMBbls 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 1.2 MMBbls 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 MMBbls of NGL storage capacity in underground caverns, 4 MMBbls of above-ground refrigerated storage, and related commercial agreements. The terminal has a total active refined products storage capacity of approximately 1 MMBbls. 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 860 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.
- The Eastern region refined products pipelines consist of approximately 615 miles of 6-inch to 16-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 180 miles of various diameters refined products pipeline in New Jersey (including 80 miles of the 16-inch diameter Harbor Pipeline).
- The midcontinent region refined products pipelines primarily consist of approximately 296 miles of 3-inch to 12-inch refined products pipelines in Ohio and approximately 53 miles of 6-inch and 8-inch refined products pipeline in Michigan.
- The Southwest region refined products pipelines are located in Eastern Texas and consist primarily of approximately 876 miles of 8-inch diameter refined products pipeline.
- The Inland refined products pipeline is approximately 580 miles of pipeline in Ohio, consisting of 72 miles of 12-inch diameter refined products pipeline in Northwest Ohio, 206 miles of 10-inch diameter refined products pipeline in vicinity of Columbus, Ohio, 135 miles of 8-inch diameter refined products pipeline in western Ohio, and 168 miles of 6-inch diameter refined products pipeline in Northeast Ohio.
- The JC Nolan Pipeline is a joint venture between a wholly-owned subsidiary of the Partnership and a wholly-owned subsidiary of Sunoco LP, which transports diesel fuel from a tank farm in Hebert, Texas to Midland, Texas, and was placed into service in July 2019 and has a throughput capacity of approximately 36 MBbls/d.
- We have approximately 35 refined products terminals with an aggregate storage capacity of approximately 8 MMBbls 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 7 MMBbls, 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 MMBbls of refined products storage. The terminal receives and delivers refined products via pipeline and primarily provides terminalling services to support movements on our refined products pipelines.
- The JC Nolan Terminal, located in Midland, Texas, is a joint venture between a wholly-owned entity of the Partnership and wholly-owned entity of Sunoco LP, which provides diesel fuel storage that was placed into service in August 2019.
- 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 1,055-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; a 14% membership interest in the Yellowstone Pipe Line Company, a 710-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 the crude oil transportation and services segment:

Description of Assets	Ownership Interest	Miles of Crude Pipeline [1]	Working Storage Capacity (MBbls)
Dakota Access Pipeline	36.4%	1,172	—
Energy Transfer Crude Oil Pipeline	36.4%	744	—
Bayou Bridge Pipeline	60%	212	—
Permian Express Pipelines	87.7%	1,712	—
Wattenberg Oil Trunkline	100%	75	360
White Cliffs Pipeline[2]	51%	527	100
Maurepas Pipeline	51%	106	—
Other Crude Oil Pipelines	100%	6,222	—
Nederland Terminal	100%	—	29,000
Fort Mifflin Terminal	100%	—	3,175
Eagle Point Terminal	100%	—	1,300
Midland Terminal	100%	—	2,000
Marcus Hook Industrial Complex	100%	—	1,000
Houston Terminal	100%	—	18,200
Cushing Facility	100%	—	7,600
Patoka, Illinois Terminal	87.7%	—	2,000

(1) Miles of pipeline as reported to PHMSA.

(2) The White Cliffs Pipeline consists of two parallel, 12-inch common carrier crude oil pipelines: one crude oil pipeline and one NGL pipeline.

Our crude oil operations consist of an integrated set of pipeline, terminalling, trucking 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 10,770 miles of crude oil trunk and gathering pipelines in the southwest, northwest and midwest United States, including our wholly-owned interests in West Texas Gulf, Permian Express Terminal LLC, Mid-Valley and Wattenberg Oil Trunkline. 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 1,916 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 1,172 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 675 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 consists of 24-inch pipe from Lake Charles, Louisiana to St. James, Louisiana, which went into service in March 2019.

  With the completion of Phase II, Bayou Bridge Pipeline has a capacity of 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, Permian Express 4, which became operational in May 2019, 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.

- *White Cliffs Pipeline.* White Cliffs Pipeline, which was acquired by ET in the SemGroup acquisition and contributed to ETO in January 2020, owns a12-inch common carrier, crude oil pipeline, with a throughput capacity of 100 MBbls/d, that transports crude oil from Platteville, Colorado to Cushing, Oklahoma.

- *Maurepas Pipeline.* The Maurepas Pipeline, which was acquired by ET in the SemGroup acquisition and contributed to ETO in January 2020, consists of three pipelines, with an aggregate throughput capacity of 460 MBbls/d, which service refineries in the Gulf Coast region.

- 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 and Kansas. We have the ability to deliver substantially all of the crude oil gathered on our Oklahoma and Kansas systems to Cushing. We are one of the largest purchasers of crude oil from producers in the area, 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 29 MMBbls 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 MMBbls/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 MMBbls.

  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 MMBbls/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 575 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. This facility has a total storage capacity of approximately 2.6 MMBbls. 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 1.3 MMBbls 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 MMBbls of crude oil storage, a combined 20 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 MMBbls.
- *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 MMBbls of crude oil storage.
- *Houston Terminal.* The Houston Terminal, which was acquired by ET in the SemGroup acquisition and contributed to ETO in February 2020, consists of storage tanks located on the Houston Ship Channel with an aggregate storage capacity of 18.2 MMBbls used to store, blend and transport refinery products and refinery feedstocks via pipeline, barge, rail, truck and ship. This facility has five deep-water ship docks on the Houston Ship Channel capable of loading and unloading Suezmax cargo vessels and seven barge docks which can accommodate 23 barges simultaneously, three crude oil pipelines connecting to four refineries and numerous rail and truck loading spots.
- *Cushing Facilities.* The Cushing Facility, which was acquired by ET in the SemGroup acquisition and contributed to ETO in January 2020, has approximately 7.6 MMBbls crude oil storage, of which 5.6 MMBbls are leased to customer and 2.0 MMBbls are available for crude oil operations, blending and marketing activities. The storage terminal has inbound connections with the White Cliffs Pipeline from Platteville, Colorado, the Great Salt Plains Pipeline from Cherokee, Oklahoma, the Cimarron Pipeline from Boyer, Kansas, and two-way connections with all of the other major storage terminals in Cushing. The Cushing terminal also includes truck unloading facilities.

Crude Oil Acquisition and Marketing

Our crude oil acquisition and marketing operations are conducted using our assets, which include approximately 575 crude oil transport trucks, 360 trailers 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 Sunoco-branded motor fuel, supplying an extensive distribution network of approximately 5,474 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;
- 537 independently operated consignment locations where Sunoco LP sells motor fuel to customers under commission agent arrangements with such operators;
- 6,742 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
- 2,581 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 and franchise royalties.

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 86.2% of its total fleet horsepower (including compression units on order) as of December 31, 2019. 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, 2019:

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	516,674	3,031	—	—	516,674	3,031
Large horsepower						
>400 and <1,000	426,384	730	9,000	15	435,384	745
>1,000	2,739,910	1,690	47,500	19	2,787,410	1,709
Total large horsepower	3,166,294	2,420	56,500	34	3,222,794	2,454
Total horsepower	3,682,968	5,451	56,500	34	3,739,468	5,485

(1) As of December 31, 2019, USAC had 56,500 large horsepower compression units on order for delivery during 2020.

All Other

The following details the significant assets in the "All Other" segment.

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, 2019, we owned or controlled approximately 762 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 Refined Products

In markets served by our crude oil and refined products 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.

Our 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, 2019, 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 of 1938 ("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 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 the 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 of 1978 ("NGPA"). The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates and terms and conditions of some transportation and storage services provided on the Oasis pipeline, HPL System, East Texas pipeline, 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 the 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 segments of the natural gas industry. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC's regulatory changes may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action in a manner that is materially different from other natural gas marketers with whom we compete.

Regulation of Gathering Pipelines. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own a number of natural gas pipelines in Texas, Louisiana and West Virginia that we believe meet the traditional tests the FERC uses to establish a pipeline's status as a 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, the 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 the 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 the 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 the 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 the 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 the FERC's order and remanded to the FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. In December 2016, the FERC issued a Notice of Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs. The 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, the FERC issued a Revised Policy Statement on Treatment of Income Taxes in which the 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 the FERC's discounted cash flow methodology. The 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. The 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, the 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. The 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 the FERC's existing ratemaking policies, including cost-of-service rate proceedings resulting from shipper-initiated complaints. In July 2018, the 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.

Effective January 2018, the 2017 Tax Cuts and Jobs Act changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. With the lower tax rate, and as discussed immediately above, the maximum tariff rates allowed by the FERC under its rate base methodology for master limited partnerships may be impacted by a lower income tax allowance component. Many of our interstate pipelines, such as Tiger, 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 PEPL, have a mix of tariff rate, discount rate, and negotiated rate agreements. In addition, several of these pipelines are covered by approved settlements, where rate filings will be made in the future. As such, the timing and impact of these systems of any tax change is unknown at this time.

In March 2019, following the decision of the D.C. Circuit in Emera Maine v. Federal Energy Regulatory Commission, FERC issued a Notice of Inquiry regarding its policy for determining return on equity ("ROE"). FERC specifically sought information and stakeholder views to help FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities. FERC also expressly sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. Initial comments were due in June 2019, and reply comments were due in July 2019. FERC has not taken any further action with respect to the Notice of Inquiry as of this time, and therefore we cannot predict what effect, if any, such development could have on our cost-of-service rates in the future.

The EPAct of 1992 required the FERC to establish a simplified and generally applicable methodology to adjust tariff rates for inflation for interstate petroleum pipelines. As a result, the 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. The 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, the 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 two 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. The FERC has taken no further action on the proposed rule to date.

Finally, in November 2017, the 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, the 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 the FERC clarify its November 2017 order or, in the alternative, grant rehearing of the November 2017 order. The FERC extended the time frame to respond to such requests in January 2018, but has not yet taken final action. We are unable to predict how the FERC will respond to such requests. Depending on how the 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 the 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 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 July 2019, PHMSA issued a final rule increasing those maximum civil penalties to $218,647 per day, with a maximum of $2,186,465 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 was issued by PHMSA in January 2020. 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 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, 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. In October 2019, PHMSA submitted three major rules to the Federal Register, including rules focused on: the safety of gas transmission pipelines (the first of three parts of the Mega Rule), the safety of hazardous liquid pipelines, and enhanced emergency order procedures. The gas transmission rule requires operators of gas transmission pipelines constructed before 1970 to determine the material strength of their lines by reconfirming MAOP. In addition, the rule updates reporting and records retention standards for gas transmission pipelines. This rule will take effect on July 1, 2020. PHMSA is then expected to issue the second part of the Mega Rule focusing on repair criteria in HCAs and creating new repair criteria for non-HCAs, requirements for inspecting pipelines following extreme events, updates to pipeline corrosion control requirements, and various other integrity management requirements. PHMSA is expected to subsequently issue the final part of the gas Mega Rule, the Gas Gathering Rule, focusing on requirements relating to gas gathering lines.

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. The safety and hazardous liquid pipelines rule discussed above, submitted to the Federal Register by PHMSA in October 2019, extended leak detection requirements to all non-gathering hazardous liquid pipelines and requires operators to inspect affected pipelines following extreme weather events or natural disasters to address any resulting damage. This rule will also take effect on July 1, 2020. In addition, the enhanced emergency procedures rule also mentioned above focuses on increased emergency safety measures. In particular, this rule increases the authority of PHMSA to issue an emergency order that addresses unsafe conditions or hazards that pose an imminent threat to pipeline safety. Unlike the other two rules submitted in October 2019, this rule took effect on December 2, 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, the 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 was 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. In response to the decree, in April 2019, the EPA signed a determination that revision of the regulations is not necessary at this time. 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, 2019 and 2018, accruals of $317 million and $337 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 ETC Sunoco's facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $252 million and $263 million at December 31, 2019 and 2018, 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 ETC Sunoco, closed and/or sold refineries and other formerly owned sites. In December 2013, a wholly-owned captive insurance company was established for these legacy sites 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, 2019, the captive insurance company held $205 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 $317 million in environmental accruals as of December 31, 2019.

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 $4 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 the 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 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 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. In January 2020, a new "waters of the United States" rule was finalized to replace the June 2015 rule. Under the final rule, the following four categories of waters would be defined as "waters of the United States": traditional navigable waters and territorial seas; perennial and intermittent tributaries to those waters; lakes, ponds and impoundments of jurisdictional waters; and wetlands adjacent to jurisdictional waters. Additional litigation and administrative proceedings are expected in the future. 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. 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 ("VOC") 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. In August 2019, the EPA proposed two options for further rescinding the Subpart OOOOa standards. Under the EPA's preferred alternative, the agency would rescind the methane limits for new, reconstructed and modified oil and natural gas production sources while leaving in place the general emission limits for volatile organic compounds, or VOCs, and relieve the EPA of its obligation to develop guidelines for methane emissions from existing sources. In addition, the proposal would remove from the oil and natural gas category the natural gas transmission and storage segment. The other proposed alternative would rescind the methane requirements of the Subpart OOOOa standards applicable to all oil and natural gas sources, without removing any sources from that source category (and still requiring control of VOCs in general). 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 United States formally initiated the withdrawal process in November 2019, 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, 2019, ETO and its consolidated subsidiaries employed an aggregate of 12,517 persons, 1,495 of which are represented by labor unions. We believe that our relations with our employees are satisfactory.

SEC Reporting

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the 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. Panhandle files 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 Panhandle's Annual Report on Form 10-K, are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Inherent in an Investment in Us

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

The amount of cash we can distribute to our Unitholders depends upon the amount of cash we generate from our operations and from our subsidiaries, Sunoco LP and USAC. The amount of cash we generate from our operations will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas, NGLs, crude oil and refined products transported in our pipelines;
- the level of throughput in our processing and treating operations;
- the fees we charge and the margins we realize for our services;

- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil prices;
- the weather in our operating areas;
- the level of competition from other midstream, transportation and storage and other energy providers;
- the level of our operating costs;
- prevailing economic conditions; and
- the level and results of our derivative activities.

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

- the level of capital expenditures we make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow under our revolving credit facility;
- our ability to access capital markets;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our General Partner in its discretion for the proper conduct of our business.

Because of all these factors, we cannot guarantee that we will have sufficient available cash to pay a specific level of cash distributions to holders of our Unitholders.

Furthermore, our Unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and is not solely a function of profitability, which is affected by non-cash items. As a result, we may declare and/or pay cash distributions during periods when we record net losses.

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

The partnership agreements of Sunoco LP and USAC allow each partnership to issue an unlimited number of additional limited partner interests. The issuance of additional 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 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.

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

As of December 31, 2019, we had approximately $50.35 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.

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

We plan to fund our growth capital expenditures, including any new pipeline construction projects and improvements or repairs to existing facilities that we may undertake, with proceeds from sales of our debt and equity securities and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms satisfactory to us, or at all. If we are unable to finance our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

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

Increases in interest rates could 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 $7.38 billion of our consolidated debt as of December 31, 2019 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.

Changes in LIBOR reporting practices or the method in which LIBOR is determined may adversely affect the market value of our current or future debt obligations, including our revolving credit facility.

As of December 31, 2019, we had outstanding approximately $7.38 billion of debt that bears interest at variable interest rates that use the LIBOR as a benchmark rate. On July 27, 2017, the Financial Conduct Authority (the "FCA"), which regulates LIBOR, announced that it intends to stop persuading or compelling banks to submit LIBOR quotations after 2021. It is unclear whether LIBOR will cease to exist or if new methods of calculating LIBOR will be established such that it continues to exist after 2021, or whether any alternative benchmark rate will attain market acceptance as a replacement for LIBOR. It is not possible to predict the further effect of the rules of the FCA, any changes in the methods by which LIBOR is determined or any other reforms to LIBOR that may be enacted in the United Kingdom, the European Union or elsewhere. Any such developments may cause LIBOR to perform differently than in the past, or cease to exist. In addition, any other legal or regulatory changes made by the FCA, the European Commission or any other successor governance or oversight body, or future changes adopted by such body, in the method by which LIBOR is determined or the change from LIBOR to an alternative benchmark rate may result in, among other things, a sudden or prolonged increase or decrease in LIBOR, a delay in the publication of LIBOR, and changes in the rules or methodologies in LIBOR, which may discourage market participants from continuing to administer or to participate in LIBOR's determination, and, in certain situations, could result in LIBOR no longer being determined and published.

If a published U.S. dollar LIBOR rate is unavailable after 2021, the interest rates on our debt which are indexed to LIBOR will be determined using an alternative method, which may result in interest obligations which are more than or do not otherwise correlate over time with the payments that would have been made on such debt if U.S. dollar LIBOR was available in its current form or will be determined using an alternative benchmark rate as negotiated with our counterparties. Further, the same costs and risks that may lead to the discontinuation or unavailability of U.S. dollar LIBOR may make one or more of the alternative methods impossible or impracticable to determine. Alternative benchmark rate(s) may replace LIBOR and could affect our debt securities, derivative instruments, receivables, debt payments and receipts. At this time, it is not possible to predict the effect of any establishment of any alternative benchmark rate(s) and we cannot predict what alternative benchmark rate(s) will be negotiated with our counterparties. Any new benchmark rate will likely not replicate LIBOR exactly, and any changes to benchmark rates may have an uncertain impact on our cost of funds and our access to the capital markets. Any of these proposals or consequences could have a material adverse effect on our financing costs.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of our General Partner, and of ET as the indirect owner of our General Partner, may be factors in credit evaluations of us due to the significant influence of our General Partner and ET over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our General Partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the Partnership to service their indebtedness.

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

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.

The General Partner may transfer its general partner interest to a third party without the consent of the Unitholders. Furthermore, the general partner of our General Partner may transfer its general partner interest in our General Partner to a third party without the consent of the Unitholders. Any new owner of the General Partner or the general partner of the General Partner would be in a position to replace the officers of the General Partner with its own choices and to control the decisions taken by such officers.

The interruption of distributions to us from our operating subsidiaries and equity investees may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no business operations other than that of our operating subsidiaries. Our only significant assets are the equity interests we own in our operating subsidiaries and equity investees. As a result, we depend upon the earnings and cash flow of our operating subsidiaries and equity investees and any interruption of distributions to us may affect our ability to meet our obligations, including any obligations under our debt agreements, and to make distributions to our partners.

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

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

A reduction in Sunoco LP's distributions will disproportionately affect the amount of cash distributions to which ETO is entitled.

ETO indirectly owns all of the IDRs of Sunoco LP. These IDRs entitle the holder to receive increasing percentages of total cash distributions made by Sunoco LP as such entity reaches established target cash distribution levels as specified in its partnership agreement. ETO currently receives its pro rata share of cash distributions from Sunoco LP based on the highest sharing level of 50% in respect of the Sunoco LP IDRs.

A decrease in the amount of distributions by Sunoco LP to less than $0.65625 per unit per quarter would reduce ETO's percentage of the incremental cash distributions from Sunoco LP above $0.546875 per unit per quarter from 50% to 25%. As a result, any such reduction in quarterly cash distributions from Sunoco LP would have the effect of disproportionately reducing the amount of all distributions that ETO receives, based on its ownership interest in the IDRs as compared to cash distributions received from its Sunoco LP common units.

Unitholders may have liability to repay distributions.

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

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

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

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

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

- to provide for the proper conduct of our business and the businesses of our operating subsidiaries (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our preferred unitholders; 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.

Risks Related to Conflicts of Interest

Although we control Sunoco LP and USAC through our ownership of Sunoco LP's and USAC's general partners, Sunoco LP's and USAC's general partners owe fiduciary duties to 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 Sunoco LP and USAC and their respective limited partners, on the other hand. The directors and officers of Sunoco LP's and USAC's general partners have fiduciary duties to manage Sunoco LP and USAC, respectively, in a manner beneficial to us. At the same time, the general partners have fiduciary duties to manage Sunoco LP and USAC in a manner beneficial to Sunoco LP and USAC and their respective limited partners. The boards of directors of 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 Sunoco LP and USAC may arise in the following situations:

- the allocation of shared overhead expenses to Sunoco LP, USAC and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and Sunoco LP and USAC, on the other hand;
- the determination of the amount of cash to be distributed to Sunoco LP's and USAC's partners and the amount of cash to be reserved for the future conduct of Sunoco LP's and USAC's businesses;
- the determination whether to make borrowings under 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 Sunoco LP and USAC is made available for Sunoco LP and USAC to pursue; and
- any decision we make in the future to engage in business activities independent of Sunoco LP and USAC.

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

Conflicts of interest may arise because of the relationships among 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 Sunoco LP's general partner or USAC's general partner, and have fiduciary duties to manage the respective businesses of Sunoco LP and USAC in a manner beneficial to 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 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 our Unitholders and restricts the remedies available to Unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our General Partner and its affiliates and reduce the obligations to which our General Partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the duties owed by our General Partner, and our officers and directors, to the limited partners. Our partnership agreement:

- eliminates all standards of care and duties other than those set forth in our partnership agreement, including fiduciary duties, to the fullest extent permitted by law;
- permits our General Partner to make a number of decisions in its "sole discretion," which standard entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our General Partner is entitled to make other decisions in its "reasonable discretion;"
- generally provides that affiliated transactions and resolutions of conflicts of interest must be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the interests of all parties involved, including its own;
- 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;
- provides that our General Partner may consult with consultants and advisors and, subject to certain restrictions, is conclusively deemed to have acted in good faith when it acts in reliance on the opinion of such consultants and advisors; and
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our General Partner and those other persons acted in good faith.

In order to become a limited partner of our partnership, a Unitholder is required to agree to be bound by the provisions in our partnership agreement, including the provisions discussed above.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of ET. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our Unitholders' best interests. In addition, these overlapping executive officers and directors allocate their time among us and ET. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

The General Partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our Unitholders.

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

Our General Partner has conflicts of interest and limited fiduciary responsibilities that may permit our General Partner to favor its own interests to the detriment of Unitholders.

ET indirectly owns our General Partner and as a result controls us. The directors and officers of our General Partner and its affiliates have fiduciary duties to manage our General Partner in a manner that is beneficial to ET, the sole owner of our General Partner. At the same time, our General Partner has contractually-limited fiduciary duties to our Unitholders. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to ET as its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ET or their owners or affiliates over the interest of our Unitholders.

Such conflicts may arise from, among others, the following:

- our partnership agreement limits the liability and reduces the fiduciary duties of our General Partner while also restricting the remedies available to our Unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. Unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise be deemed a breach of fiduciary or other duties under applicable state law. Our General Partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to us.
- our General Partner is allowed to take into account the interests of parties in addition to us, including ET, in resolving conflicts of interest, thereby limiting its fiduciary duties to us.
- our General Partner's affiliates, including ET, are not prohibited from engaging in other businesses or activities, including those in direct competition with us.
- our General Partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings, repayments of debt, issuances of equity and debt securities and cash reserves, each of which can affect the amount of cash that is distributed to Unitholders and to ET.

- neither our partnership agreement nor any other agreement requires ET or its affiliates to pursue a business strategy that favors us. The directors and officers of the general partners of ET have a fiduciary duty to make decisions in the best interest of their members, limited partners and Unitholders, which may be contrary to our best interests.
- some of the directors and officers of ET who provide advice to us also may devote significant time to the businesses of ET and will be compensated by them for their services.
- our General Partner determines which costs, including allocated overhead costs, are reimbursable by us.
- our General Partner is allowed to resolve any conflicts of interest involving us and our General Partner and its affiliates, and any resolution of a conflict of interest by our General Partner that is fair and reasonable to us will be deemed approved by all partners and will not constitute a breach of the partnership agreement.
- our General Partner controls the enforcement of obligations owed to us by it.
- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.
- our General Partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- our General Partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us.
- in some instances, our General Partner may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

Affiliates of our General Partner may compete with us.

Except as provided in our partnership agreement, affiliates and related parties of our General Partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

Risks Related to Our Business

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

Certain of our operations are conducted through joint ventures, some of which have their own governing boards. With respect to our joint ventures, we share ownership and management responsibilities with partners that may not share our goals and objectives. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in their or the joint venture's best interests. Likewise, we may be unable to prevent actions of the joint venture. Differences in views among joint venture partners may result in delayed decisions or failures to agree on major matters, such as large expenditures or contractual commitments, the construction or acquisition of assets or borrowing money, among others. Delay or failure to agree may prevent action with respect to such matters, even though such action may serve our best interest or that of the joint venture. Accordingly, delayed decisions and disagreements could adversely affect the business and operations of the joint ventures and, in turn, our business and operations.

We and our subsidiaries, including Sunoco LP and USAC, are exposed to the credit risk of our customers and derivative counterparties, and an increase in the nonpayment and nonperformance by our customers or derivative counterparties could reduce our ability to make distributions to our Unitholders.

The risks of nonpayment and nonperformance by our, Sunoco LP's and USAC's customers are a major concern in our business. Participants in the energy industry have been subjected to heightened scrutiny from the financial markets in light of past collapses and failures of other energy companies. We, Sunoco LP and USAC are subject to risks of loss resulting from nonpayment or nonperformance by our, Sunoco LP's and USAC's customers. Commodity price volatility and/or 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 and nonperformance by our 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 our customers could have a material effect on our, Sunoco LP's and USAC's 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.

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

The prices for natural gas, NGLs, crude oil and refined 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 oil production;
- the level of natural gas, NGL, and oil imports and exports, including liquefied natural gas;
- actions taken by natural gas and oil producing nations;
- instability or other events affecting natural gas and oil producing nations;
- the impact of weather and other events of nature on the demand for natural gas, NGLs and oil;
- the availability of storage, terminal and transportation systems, and refining, processing and treating facilities;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- 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 oil have been extremely volatile, and we expect this volatility to continue.

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

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

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

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

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

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

We 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 our revenues and limit our future profitability.

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

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

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

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

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

Our midstream facilities and transportation pipelines provide services related to natural gas wells that experience production declines over time, which we 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 our gathering systems and transportation pipeline systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies and natural gas transportation services.

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

While a substantial portion of our services are provided under long-term contracts for reserved service, we also provide service on an unreserved basis. 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 we provide and a decrease in the number and volume of our contracts for reserved transportation service over the long run, which in each case would adversely affect our revenues and results of operations.

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

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

For a portion of the natural gas gathered on our systems, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices.

We also enter into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers.

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

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

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

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

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

For our midstream segment, we generally analyze gross margin 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, 2019, 2018 and 2017, segment margin (a non-GAAP measure discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations") from our midstream segment totaled $2.45 billion, $2.38 billion and $2.18 billion, respectively, of which fee-based revenues constituted 82%, 75% and 77%, respectively, and non-fee based margin constituted 18%, 25% and 23%, respectively. The amount of segment margin earned by our midstream segment 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.

A material decrease in demand or distribution of crude oil available for transport through our 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 our crude oil pipelines and terminal facilities depends on the availability of attractively priced crude oil produced or received in the areas serviced by our 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 our customers, could materially reduce demand for crude oil in these areas. In either case, the volumes of crude oil transported in our crude oil pipelines and terminal facilities could decline, and it could likely be difficult to secure alternative sources of attractively priced crude oil supply in a timely fashion or at all. If we are unable to replace any significant volume declines with additional volumes from other sources, our results of operations, financial position, or cash flows could be materially and adversely affected.

Shifts in the overall supply of, and demand for, crude oil in regional, national and global markets, over which we have no control, can have an adverse impact on crude oil index prices in the markets we serve relative to other index prices. A prolonged decline in the WTI Index price, relative to other index prices, may cause reduced demand for our transportation to, and storage in, Cushing, which could have a material adverse effect on our business, results of operations and financial condition.

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

While we are 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 we 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 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 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 serves would reduce their ability to make distributions to its unitholders.

Sales of refined motor fuels account for approximately 97% of Sunoco LP’s total revenues and 74% of continuing operations gross profit. A significant decrease in demand for motor fuel in the areas Sunoco LP serves could significantly reduce revenues and Sunoco LP’s ability to make distributions to its 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 its unitholders.

The industries in which Sunoco LP operates are subject to seasonal trends, which may cause its operating costs to fluctuate, affecting its 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 its 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 its 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 its 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 its 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 its 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 its 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 its 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. For the year ended December 31, 2019, approximately 36% 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.

The use of derivative financial instruments could result in material financial losses by us.

From time to time, we and/or our subsidiaries have sought to reduce our exposure to fluctuations in commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms and by our trading, marketing and/or system optimization activities. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

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.

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

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

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

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

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

Further, whether we have the power of eminent domain for our pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state and the ownership of the land to which we seek access. When we exercise eminent down rights or negotiate private agreements cases, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located. For example, following a 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 our real property, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to Unitholders.

Sunoco LP does not own all of the land on which its retail service stations are located, and Sunoco LP leases certain facilities and equipment, and Sunoco LP is subject to the possibility of increased costs to retain necessary land use which could disrupt its operations.

Sunoco LP does not own all of the land on which its retail service stations are located. Sunoco LP has rental agreements for approximately 38.0% of the company, commission agent or dealer operated retail service stations where Sunoco LP currently controls the real estate. Sunoco LP also 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.

We, Sunoco LP and USAC may not be able to fully execute our growth strategy if we encounter increased competition for qualified assets.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream, transportation, storage and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding the acquisition of additional assets and businesses, stand-alone development projects or other transactions that we believe will present opportunities to realize synergies and increase our cash flow.

Consistent with our strategy, we may, from time to time, engage in discussions with potential sellers regarding the possible acquisition of additional assets or businesses. Such acquisition efforts may involve our participation in processes that involve a number of potential buyers, commonly referred to as "auction" processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot give assurance that our acquisition efforts will be successful or that any acquisition will be completed on terms considered favorable to us.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in us losing to other bidders more often or acquiring assets at higher prices, both of which would limit our ability to fully execute our growth strategy. Inability to execute our growth strategy may materially adversely impact our results of operations.

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

As of December 31, 2019, our consolidated balance sheet reflected $4.90 billion of goodwill and $5.70 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 third quarter of 2019, the Partnership recognized a goodwill impairment of $12 million related to the Southwest Gas operations within the interstate segment primarily due to decreases in projected future revenues and cash flows. During the fourth quarter of 2019, the Partnership recognized a goodwill impairment of $9 million related to our North Central operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows.

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 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. During 2017, Sunoco LP recognized goodwill an impairment of $102 million on its retail reporting unit.

If we and our subsidiaries do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our results of operations and our ability to grow and to make distributions to Unitholders will depend in part on our ability to make acquisitions that are accretive to our distributable cash flow per unit.

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

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

Furthermore, even if we consummate acquisitions that we believe will be accretive, those acquisitions may in fact adversely affect our results of operations or result in a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that we may:

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;
- less effectively manage our historical assets, due to the diversion of management's attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

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

If we do not continue to construct new pipelines, our future growth could be limited.

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

- we are unable to identify pipeline construction opportunities with favorable projected financial returns;
- we are unable to obtain necessary governmental approvals and contracts with qualified contractors and vendors on acceptable terms;
- we are unable to raise financing for our identified pipeline construction opportunities; or
- we are unable to secure sufficient transportation commitments from potential customers due to competition from other pipeline construction projects or for other reasons.

Furthermore, even if we construct a pipeline that we believe will be accretive, the pipeline may in fact adversely affect our results of operations or results from those projected prior to commencement of construction and other factors.

Expanding our business by constructing new pipelines and related facilities subjects us to risks.

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

We depend on certain key producers for our supply of natural gas and the loss of any of these key producers could adversely affect our financial results.

Certain producers who are connected to our systems represent a material source of our supply of natural gas. We are not the only option available to these producers for disposition of the natural gas they produce. To the extent that these and other producers may reduce the volumes of natural gas that they supply us, we would be adversely affected unless we were able to acquire comparable supplies of natural gas from other producers.

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

During 2019, Trafigura US Inc. accounted for approximately 33% of our intrastate transportation and storage revenues. During 2019, Shell, Ascent Resources LLC and Antero Resources Corporation collectively accounted for 41% of our interstate transportation and storage revenues.

Our joint ventures, FEP and Citrus, also depend on key customers for the transport of natural gas through their pipelines. FEP has a small number of major shippers with one shipper accounting for approximately 54% of its revenues in 2019 while Citrus has long-term agreements with its top three customers which accounted for 58% of its 2019 revenue. For Trans-Pecos and Comanche Trail, CFE International LLC is the sole shipper.

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

Our storage operations are influenced by the overall forward market for crude oil and other products we store, and certain market conditions may adversely affect its financial and operating results.

Our storage operations are influenced by the overall forward market for crude oil and other products we store. A contango market (meaning that the price of crude oil or other products for future delivery is higher than the current price) is associated with greater demand for storage capacity, because a party can simultaneously purchase crude oil or other products at current prices for storage and sell at higher prices for future delivery. A backwardated market (meaning that the price of crude oil or other products for future delivery is lower than the current price) is associated with lower demand for storage capacity because a party can capture a premium for prompt delivery of crude oil or other products rather than storing it for future sale. A prolonged backwardated market, or other adverse market conditions, could have an adverse impact on its ability to negotiate favorable prices under new or renewing storage contracts, which could have an adverse impact on our storage revenues. As a result, the overall forward market for crude oil or other products may have an adverse effect on our financial condition or results of operations.

An increase in interest rates could impact demand for our storage capacity.

There is a financing cost for a storage capacity user to own crude oil while it is stored. That financing cost is impacted by the cost of capital or interest rate incurred by the storage user, in addition to the commodity cost of the crude oil in inventory. Absent other factors, a higher financing cost adversely impacts the economics of storing crude oil for future sale. As a result, a significant increase in interest rates could adversely affect the demand for our storage capacity independent of other market factors.

Increasing levels of congestion in the Houston Ship Channel could result in a diversion of business to less busy ports.

Our Gulf Coast facilities are strategically situated on prime real estate located in the Houston Ship Channel, which is in close proximity to both supply sources and demand sources. In recent years, the success of the Port of Houston has led to an increase in vessel traffic driven in part by the growing overseas demand for U.S. crude, gasoline, liquefied natural gas and petrochemicals and in part by the Port of Houston's recent decision to accept large container vessels, which can restrict the flow of other cargo. Increasing congestion in the Port of Houston could cause our customers or potential customers to divert their business to smaller ports in the Gulf of Mexico, which could result in lower utilization of our facilities.

Increased regulation of hydraulic fracturing or produced water disposal could result in reductions or delays in crude oil and natural gas production in our areas of operation, which could adversely impact its business and results of operations.

The hydraulic fracturing process has come under considerable scrutiny from sections of the public as well as environmental and other groups asserting that chemicals used in the hydraulic fracturing process could adversely affect drinking water supplies and may have other detrimental impacts on public health, safety, welfare and the environment. In addition, the water disposal process has come under scrutiny from sections of the public as well as environmental and other groups asserting that the operation of certain water disposal wells has caused increased seismic activity. The adoption of new laws or regulations imposing additional permitting, disclosures, restrictions or costs related to hydraulic fracturing or produced water disposal or prohibiting hydraulic fracturing in proximity to areas considered to be environmentally sensitive could make drilling certain wells impossible or less economically attractive. As a result, the volume of crude oil and natural gas we gather, transport and store for our customers could be substantially reduced which could have an adverse effect on our financial condition or results of operations.

Competition for water resources or limitations on water usage for hydraulic fracturing could disrupt crude oil and natural gas production from shale formations.

Hydraulic fracturing is the process of creating or expanding cracks by pumping water, sand and chemicals under high pressure into an underground formation in order to increase the productivity of crude oil and natural gas wells. Water used in the process is generally fresh water, recycled produced water or salt water. There is competition for fresh water from municipalities, farmers, ranchers and industrial users. In addition, the available supply of fresh water can also be reduced directly by drought. Prolonged drought conditions increase the intensity of competition for fresh water. Limitations on oil and gas producers' access to fresh water may restrict their ability to use hydraulic fracturing and could reduce new production. Such disruptions could potentially have a material adverse impact on our financial condition or results of operations.

Our 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 our interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs.

We are required to file tariff rates (also known as recourse rates) with the FERC that shippers may 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. 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 us and find that our rates were not just and reasonable or unduly discriminatory, the maximum rates we are permitted to charge may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

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

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

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before the FERC and the courts for a number of years. 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 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, the 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.

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

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

- terms and conditions of service;
- the types of services interstate pipelines may or must offer their customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. In addition, we cannot guarantee that the FERC will authorize tariff changes and other activities we might propose and to undertake in a timely manner and free from potentially burdensome conditions. Future changes to laws, regulations, policies and interpretations thereof may impair our access to capital markets or may impair the ability of our interstate pipelines to compete for business, may impair their ability to recover costs or may increase the cost and burden of operation.

The current FERC Chairman announced in December 2017 that the FERC will review 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 that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline company operating in the United States.

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

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

The primary ratemaking methodology used by the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. The FERC's ratemaking methodologies may limit our ability to set rates based on our costs or may delay the use of rates that reflect increased costs. In October 2016, the 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 two 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 March 17, 2017. The 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 our 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 our FERC-regulated pipelines. A person challenging a grandfathered rate must, as a threshold matter, establish a substantial change since the date of enactment of the Energy Policy Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. If the FERC were to find a substantial change in circumstances, then the existing rates could be subject to detailed review and there is a risk that some rates could be found to be in excess of levels justified by the pipeline's costs. In such event, the FERC could order us to reduce pipeline rates prospectively and to pay refunds to shippers.

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

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

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

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

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

We are subject to other forms of state regulation, including requirements to obtain operating permits, reporting requirements, and safety rules (see description of federal and state pipeline safety regulation below). Violations 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 our assets may become subject to regulation.

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

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. Lone Star's NGL Pipeline transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGLs transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. In 2013, Lone Star's NGL pipeline also commenced the interstate transportation of NGLs, which is subject to the 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 the 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 the 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.

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

Pursuant to authority under the NGPSA and HLPSA, 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 segments 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 ("MAOP"); 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. In October 2019, PHMSA submitted three major rules to the Federal Register, including rules focused on: the safety of gas transmission pipelines (the first of three parts of the so-called gas Mega Rule), the safety of hazardous liquid pipelines, and enhanced emergency order procedures. The gas transmission rule requires operators of gas transmission pipelines constructed before 1970 to determine the material strength of their lines by reconfirming MAOP. In addition, the rule updates reporting and records retention standards for gas transmission pipelines. PHMSA is expected to issue the second and third parts of the gas Mega Rule in the near future. The safety and hazardous liquid pipelines rule would extend leak detection requirements to all non-gathering hazardous liquid pipelines and require operators to inspect affected pipelines following extreme weather events or natural disasters to address any resulting damage. Finally, the enhanced emergency procedures rule focuses on increased emergency safety measures. In particular, this rule increases the authority of PHMSA to issue an emergency order that addresses unsafe conditions or hazards that pose an imminent threat to pipeline safety. The changes adopted or proposed by these rulemakings or made in future legal requirements could have a material adverse effect on our 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 July 2019, PHMSA issued a final rule increasing the maximum administrative fines for safety violations were increased to account for inflation, with maximum civil penalties set at $218,647 per day, with a maximum of $2,186,465 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 were issued in January 2020. 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. In October 2019, PHMSA submitted the first of the three parts of the so-called gas Mega Rule to the Federal Register. That rule, application to gas transmission pipelines, requires operators of gas transmission pipelines constructed before 1970 to determine the material strength of their lines by reconfirming MAOP. In addition, the rule updates reporting and records retention standards for gas transmission pipelines. This rule will take effect on July 1, 2020. PHMSA is then expected to issue the second part of the Mega Rule focusing on repair criteria in HCAs and creating new repair criteria for non-HCAs, requirements for inspecting pipelines following extreme events, updates to pipeline corrosion control requirements, and various other integrity management requirements. PHMSA is expected to subsequently issue the final part of the gas Mega Rule, the Gas Gathering Rule, focusing on requirements relating to gas gathering lines. 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 us 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 our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial condition.

Our 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 us to incur significant costs and liabilities.

Our 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 our pipelines, plants and facilities, impose specific health and safety standards addressing worker protection, and impose substantial liabilities for pollution resulting from our 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 action 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.

We may incur substantial environmental costs and liabilities because of the underlying risk arising out of our 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 our 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 our 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 our equipment, result in longer permitting timelines or new restrictions or prohibitions with respect to permits or projects, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. Historically, we have been able to satisfy the more stringent nitrogen oxide emission reduction requirements that affect our compressor units in ozone non-attainment areas at reasonable cost, but there is no assurance that we 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 us to maintain spill prevention control and countermeasure plans at our 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 us 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 us. 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 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 is a defendant in numerous lawsuits that allege 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. An adverse determination of liability related to these allegations or other product liability claims against ETC Sunoco. 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 ("VOC") 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. In August 2019, the EPA proposed two options for further rescinding the Subpart OOOOa standards. Under the EPA's preferred alternative, the agency would rescind the methane limits for new, reconstructed and modified oil and natural gas production sources while leaving in place the general emission limits for volatile organic compounds, or VOCs, and relieve the EPA of its obligation to develop guidelines for methane emissions from existing sources. In addition, the proposal would remove from the oil and natural gas category the natural gas transmission and storage segment. The other proposed alternative would rescind the methane requirements of the Subpart OOOOa standards applicable to all oil and natural gas sources, without removing any sources from that source category (and still requiring control of VOCs in general). 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 United States formally initiated the withdrawal process in November 2019, 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.

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 OTC 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.

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

We have preferred units that are listed on the NYSE. 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, our 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.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our Common Units.

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

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

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

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

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

Additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration, development, oil spill-response and decommissioning plans, and other related developments may have a material adverse effect on our business, financial condition, or results of operations.

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 our 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 our 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 our 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 our services, which could have a material adverse effect on our business as well as our 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 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 patented 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 unionized employees.

As of December 31, 2019, 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 we 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.

Our 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 our 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. Our 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. We also rely primarily on four vendors, A G Equipment Company, Alegacy Equipment, LLC, Standard Equipment Corp. and Genis Holdings LLC, to package and assemble our compression units. We do 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 our results of operations and could damage our customer relationships. Some of these suppliers manufacture the components we purchase in a single facility, and any damage to that facility could lead to significant delays in delivery of completed compression units to us.

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.

Fraudulent activity or misuse of proprietary data involving its outsourcing partners could expose us to additional liability.

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

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.

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

On July 27, 2016, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia challenging permits issued by the United States Army Corps of Engineers ("USACE") permitting Dakota Access, LLC ("Dakota Access") to cross the Missouri River at Lake Oahe in North Dakota. The case was subsequently amended to challenge an easement issued by the USACE allowing the pipeline to cross land owned by the USACE adjacent to the Missouri River. Dakota Access and the Cheyenne River Sioux Tribe ("CRST") intervened. Separate lawsuits filed by the Oglala Sioux Tribe ("OST") and the Yankton Sioux Tribe ("YST") were consolidated with this action and several individual tribal members intervened (collectively with SRST and CRST, the "Tribes"). Plaintiffs and Defendants filed cross motions for summary judgment which are pending before the court.

While we believe that the pending lawsuits are unlikely to adversely affect the continued operation or potential expansion 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 and/or regulatory proceedings or actions of this or a similar nature could result in interruptions to construction or operations of current or 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.

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.

Tax Risks to Unitholders

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

The anticipated after-tax economic benefit of an investment in our Series A Preferred Units, Series B Preferred Units, Series C Preferred Units, Series D Preferred Units, Series E Preferred Units, Series F Preferred Units, and Series G Preferred Units (collectively, "ETO Preferred Units") depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS, with respect to our classification as a partnership for federal income tax purposes. Despite the fact that we are a limited partnership under Delaware law, we would 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 satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we 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 holders of our ETO Preferred Units ("ETO Preferred Unitholders") would generally be taxed again as corporate distributions and instead of guaranteed payments for the use of capital, as described further below. Because a tax would then be imposed upon us as a corporation, our cash available for distribution to ETO Preferred 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 ETO Preferred Unitholders.

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 ETO Preferred 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 otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our ETO Preferred 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 ETO Preferred 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 us. 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 us.

If the IRS contests the federal income tax positions we take, the market for our ETO Preferred Units may be adversely affected and the costs of any such contest will reduce cash available for distributions to our ETO Preferred 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 ETO Preferred 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 ETO Preferred 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 ETO Preferred 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 ETO Preferred Unitholder and former ETO Preferred Unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our Unitholders and former Unitholders, including ETO Preferred Unitholders and former ETO Preferred 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 ETO Preferred Unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such ETO Preferred Unitholders did not own ETO Preferred Units 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 ETO Preferred Unitholders might be substantially reduced.

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

ETO Preferred Unitholders, who will be treated as our partners, may receive allocations of taxable income different in amount than the cash we distribute. ETO Preferred 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. ETO Preferred 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-exempt entities and non-U.S. persons face unique tax issues from owning our ETO Preferred Units that may result in adverse tax consequences to them.

Investment in the ETO Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-United States persons raises issues unique to them. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for federal income tax purposes. Distributions to non-United States ETO Preferred Unitholders will be subject to withholding taxes. If the amount of withholding exceeds the amount of United States federal income tax actually due, non-United States ETO Preferred Unitholders may be required to file United States federal income tax returns in order to seek a refund of such excess.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a non-United States ETO Preferred 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 finalized. Non-United States ETO Preferred Unitholders should consult a tax advisor before investing in our ETO Preferred 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 currently 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 ETO Preferred 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.

An ETO Preferred Unitholder whose ETO Preferred Units are the subject of a securities loan (e.g. a loan to a "short seller") to cover a short sale of ETO Preferred Units may be considered as having disposed of those ETO Preferred Units. If so, the ETO Preferred Unitholder would no longer be treated for tax purposes as a partner with respect to those ETO Preferred 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, an ETO Preferred Unitholder whose ETO Preferred Units are the subject of a securities loan may be considered as having disposed of the loaned ETO Preferred Units. In that case, the ETO Preferred Unitholder may no longer be treated for tax purposes as a partner with respect to those ETO Preferred Units during the period of the loan and may recognize gain or loss from such disposition. ETO Preferred Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their ETO Preferred 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 ETO Preferred Units.

ETO Preferred 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 ETO Preferred Units.

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

Treatment of distributions on our ETO Preferred Units as guaranteed payments for the use of capital is uncertain and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

The tax treatment of distributions on our ETO Preferred Units is uncertain. We will treat ETO Preferred Unitholders as partners for tax purposes and will treat distributions on the ETO Preferred Units as guaranteed payments for the use of capital that will generally be taxable to ETO Preferred Unitholders as ordinary income. ETO Preferred Unitholders will recognize taxable income from the accrual of such a guaranteed payment (even in the absence of a contemporaneous cash distribution). Otherwise, except in the case of our liquidation, ETO Preferred Unitholders are generally not anticipated to share in our items of income, gain, loss or deduction, nor will we allocate any share of our nonrecourse liabilities to ETO Preferred Unitholders. If the ETO Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to ETO Preferred Unitholders.

Although we expect that much of the income we earn is generally eligible for the 20% deduction for qualified publicly traded partnership income, it is uncertain whether a guaranteed payment for the use of capital may constitute an allocable or distributive share of such income. As a result the guaranteed payment for use of capital received by our ETO Preferred Units may not be eligible for the 20% deduction for qualified publicly traded partnership income.

An ETO Preferred Unitholder will be required to recognize gain or loss on a sale of ETO Preferred Units equal to the difference between the amount realized by such ETO Preferred Unitholder and such ETO Preferred Unitholder's tax basis in the ETO Preferred Units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such ETO Preferred Unitholder receives in exchange for such ETO Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of an ETO Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the ETO Preferred Unitholder to acquire such ETO Preferred Units. Gain or loss recognized by an ETO Preferred Unitholder on the sale or exchange of ETO Preferred Units held for more than one year generally will be taxable as long-term capital gain or loss. Because ETO Preferred Unitholders will generally not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such ETO Preferred Unitholders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

All ETO Preferred Unitholders are urged to consult a tax advisor with respect to the consequences of owning our ETO Preferred Units.

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, Texas and San Antonio, Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

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

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

ITEM 3. LEGAL PROCEEDINGS

ETC Sunoco Holdings LLC and 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, 2019, Sunoco is a defendant in five cases, including one case each initiated by the States of Maryland 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 ETO, ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals L.P. ("SPMT").

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.

In October 2016, 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 case went to hearing in March 2017. On November 14, 2019, PHMSA issued a Final Order that upheld the two alleged violations and resultant civil penalty in the amount of $251,800. The full payment was made on November 27, 2019, and the case is now closed.

In April 2016, PHMSA issued a NOPV, PCO and Proposed Civil Penalty related to certain welding practices and procedures followed during construction of ETO's Permian Express 2 pipeline system in Texas. The case went to hearing before an Administrative Hearing Officer in November 2016. Recently, PHMSA issued a Final Order withdrawing two of the five alleged violations and resulting in a reduction of the civil penalty from $1,278,100 to $882,600 along with ordering compliance actions.

In July 2016, PHMSA issued a NOPV, PCO and proposed civil penalty 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 case went to hearing in March 2017. The Proposed Compliance Order was fully withdrawn. On November 8, 2019, PHMSA issued a Final Order that withdrew three alleged violations and reduced the civil penalty from $1,539,800 to $1,019,200. The full payment was made on December 9, 2019 and the case is now closed.

In late 2016, FERC Enforcement Staff began a non-public investigation of Rover's removal 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. In mid-2017, FERC Enforcement Staff began a non-public investigation regarding allegations that diesel fuel may have been included in the drilling mud at the Tuscarawas River horizontal directional drilling ("HDD") operations. Rover and the Partnership are cooperating with the investigations. Enforcement Staff has provided Rover its non-public preliminary findings regarding those investigations. The company disagrees with those findings and intends to vigorously defend against any potential penalty. Given the stage of the proceedings, and the non-public nature of the investigation, the Partnership is unable at this time to provide an assessment of the potential outcome or range of potential liability, if any.

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and other defendants (collectively, the "Defendants") seeking to recover approximately $2.6 million in civil penalties allegedly owed and certain injunctive relief related to permit compliance. The Defendants filed several motions to dismiss, which were granted on all counts. The Ohio EPA appealed, and on December 9, 2019, the Fifth District court of appeals entered a unanimous judgment affirming the trial court. The Ohio EPA sought review from the Ohio Supreme Court, which Defendants intend to oppose.

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.

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.

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.

In January 2019, we received notice from the DOJ on behalf of the EPA that a civil penalty enforcement action was being pursued under the Clean Water Act for an estimated 450 barrel crude oil release from the Mid-Valley Pipeline operated by SPLP and owned by Mid-Valley Pipeline Corporation. 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, remedial work and primary restoration in three phases and the primary restoration has been acknowledged to be complete. Operation and maintenance (O&M) activities will continue for several years. In December of 2019, SPLP reached an agreement in principal with the EPA regarding payment of a civil penalty which will be subject to public comment. The DOJ, on behalf of United States Department of Interior Fish and Wildlife, and the Ohio Attorney General, on behalf of the Ohio EPA, along with technical representatives from those agencies have been discussing natural resource damage assessment claims related to state endangered species and compensatory restoration. The timing and 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.

On September 10, 2018, a pipeline release and fire (the "Incident") occurred on the Revolution pipeline, a natural gas gathering line located in Center Township, Beaver County, Pennsylvania. There were no injuries. On February 8, 2019, the Pennsylvania Department of Environmental Protection ("PADEP") issued a Permit Hold on any requests for approvals/permits or permit amendments for any project in Pennsylvania pursuant to the state's water laws. The Partnership filed an appeal of the Permit Hold with the Pennsylvania Environmental Hearing Board. On January 3, 2020, the Partnership entered into a Consent Order and Agreement with the Department in which, among other things, the Permit Hold was lifted, the Partnership agreed to pay a $28.6 million civil penalty and fund a $2 million community environmental project, and all related appeals were withdrawn.

The Pennsylvania Office of Attorney General has commenced an investigation regarding the Incident, and the United States Attorney for the Western District of Pennsylvania has issued a federal grand jury subpoena for documents relevant to the Incident. The scope of these investigations is not further known at this time.

On June 4, 2019, the Oklahoma Corporation Commission's ("OCC") Transportation Division filed a complaint against SPLP seeking a penalty of up to $1 million related to a May 2018 rupture near Edmond, Oklahoma. The rupture occurred on the Noble to Douglas 8" pipeline in an area of external corrosion and caused the release of approximately fifteen barrels of crude oil. SPLP responded immediately to the release and remediated the surrounding environment and pipeline in cooperation with the OCC. The OCC filed the complaint alleging that SPLP failed to provide adequate cathodic protection to the pipeline causing the failure. SPLP is negotiating a settlement agreement with the OCC for a lesser penalty.

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 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 10 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

Description of Units

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. In April 2019, ETO issued 32 million of its 7.600% Series E Preferred Units at a price of $25 per unit. In January 2020, ETO issued 500,000 of its 6.75% Series F Preferred Units at a price of $1,000 per unit and 1.1 million of its 7.125% Series G Preferred Units at a price of $1,000 per unit.

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.

ETO Series E Preferred Units

Distributions on the Series E Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2024, at a rate of 7.600% per annum of the stated liquidation preference of $25. On and after May 15, 2024, distributions on the Series E 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 5.161% per annum. The Series E Preferred Units are redeemable at ETO's option on or after May 15, 2024 at a redemption price of $25 per Series E Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series F Preferred Units

On January 22, 2020, the Partnership issued 500,000 of its 6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units representing limited partner interest in the Partnership, at a price to the public of $1,000 per unit. Distributions on the Series F Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2025, at a rate equal to 6.750% per annum of the $1,000 liquidation preference. On and after May 15, 2025, the distribution rate on the Series F Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.134% per annum. The Series F Preferred Units are redeemable at ETO's option on or after May 15, 2025 at a redemption price of $1,000 per Series F Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series G Preferred Units

On January 22, 2020, the Partnership issued 1,100,000 of its 7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units representing limited partner interest in the Partnership, at a price to the public of $1,000 per unit. Distributions on the Series G Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2030, at a rate equal to 7.125% per annum of the $1,000 liquidation preference. On and after May 15, 2030, the distribution rate on the Series G Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.306% per annum. The Series G Preferred Units are redeemable at ETO's option on or after May 15, 2030 at a redemption price of $1,000 per Series G Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Cash Distribution Policy

General. We will distribute all of our "Available Cash" to our Unitholders within 45 days following the end of each fiscal quarter. Our general partner does not receive a distribution.

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

- Less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:
    - provide for the proper conduct of our business (including reserves for future capital expenditures and for our future capital needs);
    - comply with applicable law and/or debt instrument or other agreement; or
    - provide funds for distributions to the Preferred Unitholders.
- Plus all cash on hand on the date of determination of Available Cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facilities and in all cases used solely for working capital purposes or to pay distributions to partners.

Available Cash is more fully defined in our Partnership Agreement, which is an exhibit to this report.

ITEM 6. SELECTED FINANCIAL DATA

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

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" the Energy Transfer Merger resulted in the retrospective adjustment to consolidate Sunoco LP and Lake Charles LNG for all periods presented and USAC beginning April 2, 2018.

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" the merger of legacy ETO (the entity named Energy Transfer Partners, L.P. prior to the merger) and legacy Sunoco Logistics in April 2017 resulted in legacy ETO being treated as the surviving entity from an accounting perspective. Accordingly, the selected financial data below reflects the consolidated financial information of legacy ETO.

	Years Ended December 31,				
	2019	2018	2017	2016	2015
Statement of Operations Data:					
Total revenues	$ 54,032	$ 54,087	$ 40,523	$ 31,792	$ 36,096
Operating income	7,285	5,402	2,765	1,975	2,341
Income from continuing operations	5,186	4,039	2,952	911	1,371
Balance Sheet Data (at period end):					
Assets held for sale	—	—	3,313	3,588	3,681
Total assets	98,525	88,442	86,484	78,984	71,117
Liabilities associated with assets held for sale	—	—	75	48	42
Long-term debt, less current maturities	50,334	37,853	36,971	36,251	30,505
Total equity	35,307	36,621	36,967	28,938	29,968
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis) (1)	652	510	479	474	550
Growth (accrual basis) (1)	4,602	5,120	5,601	5,775	8,046
Cash paid for acquisitions	7	429	583	1,398	964

(1) Maintenance and growth capital expenditures include Sunoco LP’s capital expenditures related to discontinued operations for the years ended December 31, 2016 and 2015.

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

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

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

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

Overview

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

- natural gas operations, including the following:
    - natural gas midstream and intrastate transportation and storage;
    - 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.

Recent Developments

Series F and Series G Preferred Units Issuance

On January 22, 2020, ETO issued 500,000 of its 6.750% Series F Preferred Units at a price of $1,000 per unit and 1,100,000 of its 7.125% Series G Preferred Units at a price of $1,000 per unit. The net proceeds were used to repay amounts outstanding under ETO's revolving credit facility and for general partnership purposes.

ETO January 2020 Senior Notes Offering and Redemption

On January 22, 2020, ETO completed a registered offering (the "January 2020 Senior Notes Offering") of $1.00 billion aggregate principal amount of the Partnership's 2.900% Senior Notes due 2025, $1.50 billion aggregate principal amount of the Partnership's 3.750% Senior Notes due 2030 and $2.00 billion aggregate principal amount of the Partnership's 5.000% Senior Notes due 2050, (collectively, the "Notes"). The Notes are fully and unconditionally guaranteed by the Partnership's wholly owned subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis.

Utilizing proceeds from the January 2020 Senior Notes Offering, ETO redeemed its $400 million aggregate principal amount of 5.75% Senior Notes due September 1, 2020, its $1.05 billion aggregate principal amount of 4.15% Senior Notes due October 1, 2020, its $1.14 billion aggregate principal amount of 7.50% Senior Notes due October 15, 2020, its $250 million aggregate principal amount of 5.50% Senior Notes due February 15, 2020, ET's $52 million aggregate principal amount of 7.50% Senior Notes due October 15, 2020 and Transwestern's $175 million aggregate principal amount of 5.36% Senior Notes due December 9, 2020.

ETO Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the "ETO Term Loan") providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

As of December 31, 2019, the ETO Term Loan had $2.00 billion outstanding and was fully drawn. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.78%.

ET Contribution of SemGroup Assets to ETO

On December 5, 2019, ET completed the acquisition of SemGroup. During the first quarter of 2020, ET contributed certain SemGroup assets to ETO through sale and contribution transactions. The Partnership and SemGroup are under common control by ET subsequent to ET's acquisition of SemGroup; therefore, we will account for these transactions as reorganizations of entities under common control. Accordingly, beginning with the quarter ending March 31, 2020, the Partnership's consolidated financial statements will be retrospectively adjusted to reflect the consolidation of the contributed SemGroup businesses beginning December 5, 2019 (the date ET acquired SemGroup).

JC Nolan Pipeline

On July 1, 2019, ETO and Sunoco LP entered into a joint venture on the JC Nolan diesel fuel pipeline to West Texas and the JC Nolan terminal. ETO operates the pipeline for the joint venture, which transports diesel fuel from Hebert, Texas to a terminal in the Midland, Texas area. The diesel fuel pipeline has an initial capacity of 30,000 barrels per day and was successfully commissioned in August 2019.

Series E Preferred Units Issuance

In April 2019, ETO issued 32 million of its 7.600% Series E Preferred Units at a price of $25 per unit, including 4 million Series E Preferred Units pursuant to the underwriters' exercise of their option to purchase additional preferred units. The total gross proceeds from the Series E Preferred Unit issuance were $800 million, including $100 million from the underwriters' exercise of their option to purchase additional preferred units. The net proceeds were used to repay amounts outstanding under ETO's revolving credit facility and for general partnership purposes.

ET-ETO Senior Notes Exchange

In March 2019, ETO issued approximately $4.21 billion aggregate principal amount of senior notes to settle and exchange approximately 97% of ET's outstanding senior notes. In connection with this exchange, ETO issued $1.14 billion aggregate principal amount of 7.50% senior notes due 2020, $995 million aggregate principal amount of 4.25% senior notes due 2023, $1.13 billion aggregate principal amount of 5.875% senior notes due 2024 and $956 million aggregate principal amount of 5.50% senior notes due 2027.

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.

Panhandle Senior Notes Redemption

In June 2019, Panhandle's $150 million aggregate principal amount of 8.125% senior notes matured and were repaid with borrowings under an affiliate loan agreement with ETO.

Bakken Senior Notes Offering

In March 2019, Midwest Connector Capital Company LLC, a wholly-owned subsidiary of Dakota Access, issued $650 million aggregate principal amount of 3.625% senior notes due 2022, $1.00 billion aggregate principal amount of 3.90% senior notes due 2024 and $850 million aggregate principal amount of 4.625% senior notes due 2029. The $2.48 billion in net proceeds from the offering were used to repay in full all amounts outstanding on the Bakken credit facility and the facility was terminated.

Sunoco LP Senior Notes Offering

In March 2019, Sunoco LP issued $600 million aggregate principal amount of 6.00% senior notes due 2027 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP's existing borrowings under its credit facility. In July 2019, Sunoco LP completed an exchange of these notes for registered notes with substantially identical terms.

USAC Senior Notes Offering

In March 2019, USAC issued $750 million aggregate principal amount of 6.875% senior notes due 2027 in a private placement, and in December 2019, USAC exchanged those notes for substantially identical senior notes registered under the Securities Act.

The net proceeds from this offering were used to repay a portion of USAC's existing borrowings under its credit facility and for general partnership purposes.

Regulatory Update

Interstate Natural Gas Transportation Regulation

Rate 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. 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") on March 15, 2018, 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.

In March 2019, following the decision of the D.C. Circuit in Emera Maine v. Federal Energy Regulatory Commission, the FERC issued a Notice of Inquiry regarding its policy for determining return on equity ("ROE"). The FERC specifically sought information and stakeholder views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities. The FERC also expressly sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. Initial comments were due in June 2019, and reply comments were due in July 2019. The FERC has not taken any further action with respect to the Notice of Inquiry as of this time, and therefore we cannot predict what effect, if any, such development could have on our cost-of-service rates in the future.

Also 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 to address changes to the pipeline's revenue requirements as a result of the tax reductions: file a limited Natural Gas Act ("NGA") Section 4 filing reducing its rates to reflect the reduced tax rates, 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 filed a cost and revenue study on April 1, 2019. Panhandle filed a NGA Section 4 rate case on August 30, 2019.

By order issued October 1, 2019, the Panhandle Section 5 and Section 4 cases were consolidated. An initial decision is expected to be issued in the first quarter of 2021. By order issued February 19, 2019, the FERC initiated a review of Southwest Gas' existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Southwest Gas are just and reasonable and set the matter for hearing. Southwest Gas filed a cost and revenue study on May 6, 2019. On July 10, 2019, Southwest filed an Offer of Settlement in this Section 5 proceeding, which settlement was supported or not opposed by Commission Trial Staff and all active parties. The settlement was approved on October 29, 2019.

Sea Robin Pipeline Company filed a Section 4 rate case on November 30, 2018. A procedural schedule was ordered with a hearing date in the 4th quarter of 2019. Sea Robin Pipeline Company has reached a settlement of this proceeding, with a settlement filed July 22, 2019. The settlement was approved by the FERC by order dated October 17, 2019.

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.

Pipeline Certification

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 Common Carrier 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 anticipate continued earnings growth in 2020 from the recently completed projects, as well as our current 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 in recent months as associated gas from shale oil resources has provided additional supply to the market, increasing domestic supply to highs above 100 Bcf/d. Global oil and natural gas demand growth is likely to continue into the foreseeable future and will support U.S. production increases and, in turn U.S. natural gas export projects to Mexico as well as LNG exports.

For crude oil, new pipelines that came online during 2019 have resulted in Permian barrels now pricing closer to other regional hubs, which is a departure from the substantial discounts seen a year ago. These pipelines have enabled Permian producers to realize higher crude oil revenues, supporting continued growth in the region. Crude oil exports from the U.S. are continuing to increase as a result, providing additional opportunity for U.S. midstream sector growth.

Results of Operations

We report Segment Adjusted EBITDA and consolidated Adjusted EBITDA as measures of segment performance. We define Segment Adjusted EBITDA and consolidated Adjusted EBITDA as total Partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Segment Adjusted EBITDA and consolidated Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

Segment Adjusted EBITDA, as reported for each segment in the table below, is analyzed for each segment in the section titled "Segment Operating Results." Adjusted EBITDA is a non-GAAP measure used by industry analysts, investors, lenders and rating agencies to assess the financial performance and the operating results of the Partnership's fundamental business activities and should not be considered in isolation or as a substitution for net income, income from operations, cash flows from operating activities or other GAAP measures.

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data," the Energy Transfer Merger in October 2018 resulted in the retrospective adjustment of the Partnership's consolidated financial statements to reflect consolidation beginning January 1, 2017 of Sunoco LP and Lake Charles LNG and April 2, 2018 for USAC.

As discussed in Note 1 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data," the merger of legacy ETO (the entity named Energy Transfer Partners, L.P. prior to the merger) and legacy Sunoco Logistics in April 2017 resulted in legacy ETO being treated as the surviving entity from an accounting perspective. Accordingly, the financial data below reflects the consolidated financial information of legacy ETO.

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Consolidated Results

	Years Ended December 31,		
	2019	2018	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 999	$ 927	$ 72
Interstate transportation and storage	1,792	1,680	112
Midstream	1,599	1,627	(28)
NGL and refined products transportation and services	2,663	1,979	684
Crude oil transportation and services	2,949	2,330	619
Investment in Sunoco LP	665	638	27
Investment in USAC	420	289	131
All other	104	76	28
Total Segment Adjusted EBITDA	11,191	9,546	1,645
Depreciation, depletion and amortization	(3,124)	(2,843)	(281)
Interest expense, net of interest capitalized	(2,257)	(1,709)	(548)
Impairment losses	(74)	(431)	357
Gains (losses) on interest rate derivatives	(241)	47	(288)
Non-cash compensation expense	(111)	(105)	(6)
Unrealized losses on commodity risk management activities	(4)	(11)	7
Inventory valuation adjustments	79	(85)	164
Losses on extinguishments of debt	(2)	(109)	107
Adjusted EBITDA related to unconsolidated affiliates	(621)	(655)	34
Equity in earnings of unconsolidated affiliates	298	344	(46)
Adjusted EBITDA related to discontinued operations	—	25	(25)
Other, net	252	30	222
Income from continuing operations before income tax expense	5,386	4,044	1,342
Income tax expense from continuing operations	(200)	(5)	(195)
Income from continuing operations	5,186	4,039	1,147
Loss from discontinued operations, net of income taxes	—	(265)	265
Net income	$ 5,186	$ 3,774	$ 1,412

Adjusted EBITDA (*consolidated*). For the year ended December 31, 2019 compared to the prior year, Adjusted EBITDA increased approximately $1.65 billion, or 17%. The increase was primarily due to the impact of multiple revenue-generating assets being placed in service and recent acquisitions, as well as increased demand for services on existing assets. The impact of new assets and acquisitions was approximately $784 million, of which the largest increases were from increased volumes to our Mariner East pipeline and terminal assets due to the addition of pipeline capacity in the fourth quarter of 2018 (a $274 million impact to the NGL and refined products transportation and services segment), the commissioning of our fifth and sixth fractionators (a $131 million impact to the NGL and refined products transportation and services segment), the ramp up of volumes on our Bayou Bridge system due to placing phase II in service in the second quarter of 2019 (a $60 million impact to our crude oil transportation and services segment), the Rover pipeline (a $78 million impact to the interstate transportation and storage segment), the addition of gas processing capacity to our Arrowhead gas plant (a $31 million impact to our midstream segment), placing our Permian Express 4 pipeline in service in October 2019 (a $26 million impact to our crude oil transportation and services segment) and the acquisition of USAC (a net impact of $131 million among the investment in USAC and all other segments). The remainder of the increase in Adjusted EBITDA was primarily due to stronger demand on existing assets, particularly due to increased throughput on our Bakken Pipeline system as well as increased production in the Permian, which impacted multiple segments. Additional discussion of these and other factors affecting Adjusted EBITDA is included in the analysis of Segment Adjusted EBITDA in the "Segment Operating Results" section 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 of Interest Capitalized. Interest expense, net of interest capitalized, increased during the year ended December 31, 2019 compared to the prior year primarily due to the following:

- an increase of $470 million recognized by the Partnership (excluding Sunoco LP and USAC) primarily related to an increase in long-term debt, which included $4.2 billion of senior notes issued in the ET-ETO senior note exchange (discussed below under "Description of Indebtedness"), as well as additional senior note issuances and borrowings under our revolving credit facilities;
- an increase of $49 million recognized by USAC primarily attributable to higher overall debt balances and higher interest rates on borrowings under the credit agreement. These increases were partially offset by the decrease in borrowings under the credit agreement; and
- an increase of $29 million recognized by Sunoco LP due to an increase in total long-term debt.

Impairment Losses. During the year ended December 31, 2019, the Partnership recognized goodwill impairments of $12 million related to the Southwest Gas operations within the interstate transportation and storage segment and $9 million related to our North Central operations within the midstream segment, both of which were primarily due to changes in assumptions related to projected future revenues and cash flows. Also during the year ended December 31, 2019, Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York, and USAC recognized a $6 million fixed asset impairment related to certain idle compressor assets.

During the year ended December 31, 2018, the Partnership recognized goodwill impairments of $378 million and asset impairments of $4 million related to our midstream operations and asset impairments of $9 million related to idle leased assets in our crude operations. Sunoco LP recognized a $30 million indefinite-lived intangible asset impairment related to contractual rights. USAC recognized a $9 million fixed asset impairment related to certain idle compressor assets. 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. Losses on interest rate derivatives during the year ended December 31, 2019 resulted from a decrease in forward interest rates and gains in 2018 resulted from an increase in forward interest rates.

Unrealized Losses on Commodity Risk Management Activities. The unrealized losses on our commodity risk management activities include changes in fair value of commodity derivatives and the hedged inventory included in designated fair value hedging relationships. Information on the unrealized gains and losses within each segment are included in "Segment Operating Results" below, and additional information on the commodity-related derivatives, including notional volumes, maturities and fair values, is available in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and in Note 13 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco LP primarily driven by 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.

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. For the year ended December 31, 2019 compared to the prior year, income tax expense increased due to an increase in income at our corporate subsidiaries and the recognition of a favorable state tax rate change in the prior period.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Equity in earnings of unconsolidated affiliates:			
Citrus	$ 148	$ 141	$ 7
FEP	59	55	4
MEP	15	31	(16)
Other	76	117	(41)
Total equity in earnings of unconsolidated affiliates	$ 298	$ 344	$ (46)
Adjusted EBITDA related to unconsolidated affiliates[(1)]:			
Citrus	$ 342	$ 337	$ 5
FEP	75	74	1
MEP	60	81	(21)
Other	144	163	(19)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 621	$ 655	$ (34)
Distributions received from unconsolidated affiliates:			
Citrus	$ 178	$ 171	$ 7
FEP	73	68	5
MEP	36	48	(12)
Other	96	110	(14)
Total distributions received from unconsolidated affiliates	$ 383	$ 397	$ (14)

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

Segment Operating Results

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*. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have

control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates.

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. Among the GAAP measures reported by the Partnership, the most directly comparable measure to segment margin is Segment Adjusted EBITDA; a reconciliation of segment margin to Segment Adjusted EBITDA is included in the following tables for each segment where segment margin is presented.

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 16 to our consolidated financial statements in "Item 8. Financial Statements and Supplementary Data."

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2019	2018	Change
Natural gas transported (BBtu/d)	12,442	10,873	1,569
Revenues	$ 3,099	$ 3,737	$ (638)
Cost of products sold	1,909	2,665	(756)
Segment margin	1,190	1,072	118
Unrealized losses on commodity risk management activities	2	38	(36)
Operating expenses, excluding non-cash compensation expense	(190)	(189)	(1)
Selling, general and administrative expenses, excluding non-cash compensation expense	(29)	(27)	(2)
Adjusted EBITDA related to unconsolidated affiliates	25	32	(7)
Other	1	1	—
Segment Adjusted EBITDA	$ 999	$ 927	$ 72

Volumes. For the year ended December 31, 2019 compared to the prior year, transported volumes increased primarily due to the impact of reflecting RIGS as a consolidated subsidiary beginning April 2018 and the impact of the Red Bluff Express pipeline coming online in May 2018, as well as the impact of favorable market pricing spreads.

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

	Years Ended December 31,		
	2019	2018	Change
Transportation fees	$ 614	$ 525	$ 89
Natural gas sales and other (excluding unrealized gains and losses)	505	510	(5)
Retained fuel revenues (excluding unrealized gains and losses)	50	59	(9)
Storage margin, including fees (excluding unrealized gains and losses)	23	16	7
Unrealized losses on commodity risk management activities	(2)	(38)	36
Total segment margin	$ 1,190	$ 1,072	$ 118

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 $64 million in transportation fees, excluding the impact of consolidating RIGS beginning April 2018 as discussed below, primarily due to the Red Bluff Express pipeline coming online in May 2018, as well as new contracts;
- a net increase of $11 million primarily due to the consolidation of RIGS beginning April 2018, resulting in increases in transportation fees, retained fuel revenues and operating expenses of $24 million, $2 million and $6 million, respectively, partially offset by a decrease in Adjusted EBITDA related to unconsolidated affiliates of $9 million; and
- an increase of $7 million in realized storage margin primarily due to a realized adjustment to the Bammel storage inventory of $25 million in 2018 and higher storage fees, partially offset by a $20 million decrease due to lower physical withdrawals; partially offset by
- a decrease of $9 million in retained fuel revenues primarily due to lower gas prices; and
- a decrease of $5 million in realized natural gas sales and other due to lower realized gains from pipeline optimization activity.

Interstate Transportation and Storage

	Years Ended December 31,		
	2019	2018	Change
Natural gas transported (BBtu/d)	11,346	9,542	1,804
Natural gas sold (BBtu/d)	17	17	—
Revenues	$ 1,963	$ 1,682	$ 281
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(569)	(431)	(138)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(72)	(63)	(9)
Adjusted EBITDA related to unconsolidated affiliates	477	492	(15)
Other	(7)	—	(7)
Segment Adjusted EBITDA	$ 1,792	$ 1,680	$ 112

Volumes. For the year ended December 31, 2019 compared to the prior year, transported volumes increased as a result of the addition of new contracted volumes for delivery out of the Haynesville Shale, higher volumes on our Rover pipeline as a result of the full year availability of new supply connections, and higher throughput on Trunkline and Panhandle due to increased utilization of higher contracted capacity.

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 in margin of $231 million from the Rover pipeline due to higher reservation and usage resulting from additional connections and utilization of additional compression;
- an increase of $40 million in reservation and usage fees due to improved market conditions allowing us to successfully bring new volumes to the system at improved rates, primarily on our Transwestern, Tiger and Panhandle Eastern systems; and
- an increase of $6 million from the Sea Robin pipeline due to higher rates resulting from the rate case filed in June 2019, as well as fewer third party supply interruptions on the Sea Robin system; partially offset by
- an increase of $138 million in operating expense primarily due to an increase in ad valorem taxes of $126 million on the Rover pipeline system resulting from placing the final portions of this asset into service in November 2018, an increase of $24 million in transportation expense on Rover due to an increase in transportation volumes, an increase of $5 million in allocated overhead costs and additional operating expense of $4 million for assets acquired in June 2019, partially offset by lower gas imbalance and system gas activity of $15 million and lower storage capacity leased on the Panhandle Eastern system of $8 million;
- an increase of $9 million in selling, general and administrative expenses primarily due to an increase in insurance expense of $8 million, an increase in employee cost of $4 million, and an increase in allocated overhead costs of $3 million, partially offset by lower Ohio excise tax on our Rover system; and

- a decrease of $15 million in adjusted EBITDA related to unconsolidated affiliates primarily resulting from a $20 million decrease due to lower earnings from MEP as a result of lower capacity being re-contracted at lower rates on expiring contracts, partially offset by a $5 million increase from our Citrus joint venture as we brought new volumes to the system in 2019.

Midstream

	Years Ended December 31,		
	2019	2018	Change
Gathered volumes (BBtu/d)	13,431	12,126	1,305
NGLs produced (MBbls/d)	570	540	30
Equity NGLs (MBbls/d)	31	29	2
Revenues	$ 6,019	$ 7,522	$ (1,503)
Cost of products sold	3,570	5,145	(1,575)
Segment margin	2,449	2,377	72
Operating expenses, excluding non-cash compensation expense	(789)	(705)	(84)
Selling, general and administrative expenses, excluding non-cash compensation expense	(90)	(81)	(9)
Adjusted EBITDA related to unconsolidated affiliates	27	33	(6)
Other	2	3	(1)
Segment Adjusted EBITDA	$ 1,599	$ 1,627	$ (28)

Volumes. For the year ended December 31, 2019 compared to the prior year, gathered volumes increased primarily due to increases in the Northeast, Permian, Ark-La-Tex, South Texas and North Texas regions. NGL production increased due to increases in the Permian and North Texas regions partially offset by ethane rejection in the South Texas region.

Segment Margin. The table below presents the components of our midstream segment margin. For the year ended December 31, 2018, the amounts previously reported for fee-based and non-fee-based margin have been adjusted to reflect reclassification of certain contractual minimum fees from fee-based margin to non-fee-based margin in order to conform to the current period classification.

	Years Ended December 31,		
	2019	2018	Change
Gathering and processing fee-based revenues	$ 1,998	$ 1,788	$ 210
Non-fee based contracts and processing	451	589	(138)
Total segment margin	$ 2,449	$ 2,377	$ 72

Segment Adjusted EBITDA. For the year ended December 31, 2019 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net impacts of the following:

- a decrease of $138 million in non fee-based margin due to lower NGL prices of $131 million and lower gas prices of $58 million, offset by an increase of $51 million in non fee-based margin due to increased throughput volume in North Texas, South Texas and Permian regions;
- an increase of $84 million in operating expenses due to increases of $33 million in outside services, $29 million in maintenance project costs, $17 million in employee costs and $6 million in office expenses and materials; and
- an increase of $9 million in selling, general and administrative expenses primarily due to a decrease of $5 million in capitalized overhead and an increase of $4 million in insurance expense; partially offset by
- an increase of $210 million in fee-based margin due to volume growth in the Northeast, Permian, Ark-La-Tex, North Texas and South Texas regions.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2019	2018	Change
NGL transportation volumes (MBbls/d)	1,289	1,027	262
Refined products transportation volumes (MBbls/d)	583	621	(38)
NGL and refined products terminal volumes (MBbls/d)	944	812	132
NGL fractionation volumes (MBbls/d)	706	527	179
Revenues	$ 11,641	$ 11,123	$ 518
Cost of products sold	8,393	8,462	(69)
Segment margin	3,248	2,661	587
Unrealized (gains) losses on commodity risk management activities	81	(86)	167
Operating expenses, excluding non-cash compensation expense	(656)	(604)	(52)
Selling, general and administrative expenses, excluding non-cash compensation expense	(93)	(74)	(19)
Adjusted EBITDA related to unconsolidated affiliates	83	82	1
Segment Adjusted EBITDA	$ 2,663	$ 1,979	$ 684

Volumes. For the year ended December 31, 2019 compared to the prior year, throughput barrels on our Texas NGL pipeline system increased due to higher receipt of liquids production from both wholly-owned and third-party gas plants primarily in the Permian and North Texas regions. In addition, NGL transportation volumes on our Northeast assets increased due to the initiation of service on the Mariner East 2 pipeline system.

Refined products transportation volumes decreased for the year ended December 31, 2019 compared to prior year due to the closure of a third party refinery during the third quarter of 2019, negatively impacting supply to our refined products transportation system. These decreases in volumes are partially offset by the initiation of service on the JC Nolan Pipeline in the third quarter of 2019.

NGL and refined products terminal volumes increased for the year ended December 31, 2019 compared to the prior year primarily due to the initiation of service on our Mariner East 2 pipeline system which commenced operations in the fourth quarter of 2018.

Average volumes fractionated at our Mont Belvieu, Texas fractionation facility increased for the year ended December 31, 2019 compared to the prior year primarily due to the commissioning of our fifth and sixth fractionators in July 2018 and February 2019, respectively.

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

	Years Ended December 31,		
	2019	2018	Change
Fractionators and refinery services margin	$ 664	$ 511	$ 153
Transportation margin	1,716	1,233	483
Storage margin	223	211	12
Terminal Services margin	630	494	136
Marketing margin	96	126	(30)
Unrealized gains (losses) on commodity risk management activities	(81)	86	(167)
Total segment margin	$ 3,248	$ 2,661	$ 587

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 $483 million in transportation margin primarily due to a $265 million increase resulting from the initiation of service on our Mariner East 2 pipeline in the fourth quarter of 2018, a $212 million increase resulting from higher throughput volumes received from the Permian region on our Texas NGL pipelines, a $29 million increase due to higher throughput volumes from the Barnett region, a $9 million increase from the Eagle Ford region, and a $9 million increase due to the initiation of service on the JC Nolan Pipeline. These increases were partially offset by a $21 million decrease resulting from Mariner East 1 pipeline downtime, a $13 million decrease due to the closure of a third-party refinery during the third quarter of 2019, negatively impacting refined product supply to our system, and a $5 million decrease due to the timing of deficiency fees on Mariner West;

- an increase of $153 million in fractionation and refinery services margin primarily due to a $167 million increase resulting from the commissioning of our fifth and sixth fractionators in July 2018 and February 2019, respectively, and higher NGL volumes from the Permian region feeding our Mont Belvieu fractionation facility. This increase was partially offset by a reclassification between our fractionation and storage margins;
- an increase of $136 million in terminal services margin primarily due to a $171 million increase from the initiation of service of our Mariner East 2 pipeline which commenced operations in the fourth quarter of 2018 and a $7 million increase due to increased tank lease revenue from third-party customers. These increases were partially offset by a $16 million decrease in volumes and expense reimbursements from third parties on Mariner East 1, a $16 million decrease due to lower volumes from third party pipeline, truck and rail deliveries into our Marcus Hook terminal, a $5 million decrease due to fewer vessels exported out of our Nederland terminal, and a $4 million decrease due to the closure of a third party refinery during the third quarter of 2019; and
- an increase of $12 million in storage margin primarily due to a reclassification between our storage and fractionation margins; partially offset by
- a decrease of $30 million in marketing margin primarily due to capacity lease fees incurred by our marketing affiliate on our Mariner East 2 pipeline, offset by increased gains from our butane blending business due to more favorable market conditions and increased volumes, as well as increased optimization gains from the sale of NGL component products at our Mont Belvieu facility;
- an increase of $52 million in operating expenses primarily due to a $26 million increase in employee and ad valorem tax expenses on our terminals, fractionation, and transportation operations, a $14 million increase in utility costs to operate our pipelines and our fifth and sixth fractionators which commenced July 2018 and February 2019, respectively, and an $8 million increase in maintenance project costs due to the timing of multiple projects on our transportation assets; and
- an increase of $19 million in general and administrative expenses primarily due to a $10 million increase in allocated overhead costs, a $5 million increase in insurance expenses, a $4 million increase in legal fees, and a $2 million increase in employee costs.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2019	2018	Change
Crude transportation volumes (MBbls/d)	4,662	4,172	490
Crude terminals volumes (MBbls/d)	2,068	2,096	(28)
Revenue	$ 18,307	$ 17,332	$ 975
Cost of products sold	14,649	14,439	210
Segment margin	3,658	2,893	765
Unrealized (gains) losses on commodity risk management activities	(70)	55	(125)
Operating expenses, excluding non-cash compensation expense	(560)	(547)	(13)
Selling, general and administrative expenses, excluding non-cash compensation expense	(84)	(86)	2
Adjusted EBITDA related to unconsolidated affiliates	6	15	(9)
Other	(1)	—	(1)
Segment Adjusted EBITDA	$ 2,949	$ 2,330	$ 619

Segment Adjusted EBITDA. For the year ended December 31, 2019 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 $640 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $282 million increase resulting from higher throughput on our Texas crude pipeline system primarily due to increased production from the Permian region and contributions from capacity expansion projects placed into service, a $219 million increase in throughput on our Bakken pipeline, a favorable inventory valuation adjustment of

$111 million for the 2019 year as compared to an unfavorable inventory valuation adjustment of $54 million for the 2018 year, partially offset by a $50 million reduction due to lower pipeline basis spreads net of hedges. We also realized a $66 million increase from higher volumes on our Bayou Bridge Pipeline and a $26 million increase primarily from higher throughput, ship loading and tank rental fees at our Nederland terminal; partially offset by a $54 million decrease from our Oklahoma assets resulting from lower volumes to the system as well as from the timing of a deficiency payment made in the prior year, a $12 million decrease due to the closure of a third party refinery which was the primary customer utilizing one of our northeast crude terminals. The remainder of the offsetting decrease was primarily attributable to a change in the presentation of certain intrasegment transactions, which were eliminated in the current period presentation but were shown on a gross basis in revenues and operating expenses in the prior period; partially offset by

- an increase of $13 million in operating expenses primarily due to a $30 million increase in throughput-related costs on existing assets, partially offset by a $14 million decrease in management fees as well as the impact of certain intrasegment transactions discussed above; and
- a decrease of $9 million in Adjusted EBITDA related to unconsolidated affiliates due to lower margin from jet fuel sales by our joint ventures.

Investment in Sunoco LP

	Years Ended December 31,		
	2019	2018	Change
Revenues	$ 16,596	$ 16,994	$ (398)
Cost of products sold	15,380	15,872	(492)
Segment margin	1,216	1,122	94
Unrealized (gains) losses on commodity risk management activities	(5)	6	(11)
Operating expenses, excluding non-cash compensation expense	(365)	(435)	70
Selling, general and administrative, excluding non-cash compensation expense	(123)	(129)	6
Adjusted EBITDA related to unconsolidated affiliates	4	—	4
Inventory valuation adjustments	(79)	85	(164)
Adjusted EBITDA from discontinued operations	—	(25)	25
Other, net	17	14	3
Segment Adjusted EBITDA	$ 665	$ 638	$ 27

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

Segment Adjusted EBITDA. For the year ended December 31, 2019 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:

- a decrease in operating costs of $76 million, primarily as a result of the conversion of 207 retail sites to commission agent sites during April 2018. These expenses include other operating expense, general and administrative expense and lease expense; and
- an increase of $25 million related to Adjusted EBITDA from discontinued operations related to the divestment of 1,030 company-operated fuel sites to 7-Eleven in January 2018; and
- an increase of $4 million in Adjusted EBITDA related to unconsolidated affiliates due to Sunoco LP's investment in the JC Nolan joint venture; partially offset by
- a decrease in the gross profit on motor fuel sales of $76 million (excluding the change in inventory fair value adjustments and unrealized gains and losses on commodity risk management activities) primarily due to lower fuel margins, a one-time benefit of approximately $25 million related to a cash settlement with a fuel supplier recorded in 2018 and an $8 million one-time charge related to a reserve for an open contractual dispute recorded in 2019, partially offset by an increase in gallons sold.

Investment in USAC

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Revenues	$ 698	$ 508	$ 190
Cost of products sold	91	67	24
Segment margin	607	441	166
Operating expenses, excluding non-cash compensation expense	(134)	(110)	(24)
Selling, general and administrative, excluding non-cash compensation expense	(53)	(50)	(3)
Other, net	—	8	(8)
Segment Adjusted EBITDA	$ 420	$ 289	$ 131

The investment in USAC segment reflects the consolidated results of USAC from April 2, 2018, the date ET obtained control of USAC. Changes between periods are primarily due to the consolidation of USAC beginning April 2, 2018.

All Other

	Years Ended December 31, 2019	Years Ended December 31, 2018	Change
Revenue	$ 1,660	$ 2,228	$ (568)
Cost of products sold	1,496	2,006	(510)
Segment margin	164	222	(58)
Unrealized gains on commodity risk management activities	(4)	(2)	(2)
Operating expenses, excluding non-cash compensation expense	(62)	(56)	(6)
Selling, general and administrative expenses, excluding non-cash compensation expense	(55)	(87)	32
Adjusted EBITDA related to unconsolidated affiliates	3	1	2
Other and eliminations	58	(2)	60
Segment Adjusted EBITDA	$ 104	$ 76	$ 28

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 7.4% 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, 2019 compared to the prior year, Segment Adjusted EBITDA increased due to the net impacts of the following:

- an increase of $8 million in gains from park and loan and storage activity;
- an increase of $11 million in optimized gains on residue gas sales;
- an increase of $7 million from settled derivatives;
- an increase of $15 million from a legal settlement;
- an increase of $12 million from payments related to the PES bankruptcy;
- an increase of $6 million from the recognition of deferred revenue related to a bankruptcy;
- an increase of $3 million from power trading activities; and

- a decrease of $21 million in merger and acquisition expenses; partially offset by
- a decrease of $36 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 $8 million due to lower gas prices and increased power costs; and
- a decrease of $11 million due to lower revenue from our compressor equipment business.

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Consolidated Results

	Years Ended December 31,		
	2018	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	76	219	(143)
Total	9,546	7,352	2,194
Depreciation, depletion and amortization	(2,843)	(2,541)	(302)
Interest expense, net of interest capitalized	(1,709)	(1,575)	(134)
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	(109)	(42)	(67)
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	30	154	(124)
Income from continuing operations before income tax (expense) benefit	4,044	1,148	2,896
Income tax (expense) benefit from continuing operations	(5)	1,804	(1,809)
Income from continuing operations	4,039	2,952	1,087
Loss from discontinued operations, net of income taxes	(265)	(177)	(88)
Net income	$ 3,774	$ 2,775	$ 999

Adjusted EBITDA (*consolidated*). For the year ended December 31, 2018 compared to the prior year, Adjusted EBITDA increased approximately $2.2 billion, or 30%. The increase was primarily due to the impact of multiple revenue-generating assets being placed in service and recent acquisitions, as well as increased demand for services on existing assets. The impact of new assets and acquisitions was approximately $1.2 billion, of which the largest increases were from the Bakken pipeline (a $546 million impact to the crude oil transportation and services segment), the Rover pipeline (a $359 million impact to the interstate transportation and storage segment) and the acquisition of USAC (a net impact of $191 million among the investment in USAC and all other segments). The remainder of the increase in Adjusted EBITDA was primarily due to stronger demand on existing assets, particularly due to increased production in the Permian, which impacted multiple segments. Additional discussion of these and other factors affecting Adjusted EBITDA is included in the analysis of Segment Adjusted EBITDA in the "Segment Operating Results" section 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 of Interest Capitalized. Interest expense, net of interest capitalized, increased during the year ended December 31, 2018 compared to December 31, 2017 primarily due to the following:

- an increase of $121 million recognized by the Partnership 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; 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 our midstream operations and asset impairments of $9 million related to our 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 goodwill impairments of $223 million related to the compression business, $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. 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 discussion of the unrealized gains (losses) on commodity risk management activities included in "Segment Operating Results" below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco 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 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 in 2018 and 2017 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 $1.78 billion in December 2017. For the year ended December 2018, the Partnership recorded an income tax expense due to pre-tax income at its corporate subsidiaries, partially offset by a 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	110	80	30
Total distributions received from unconsolidated affiliates	$ 397	$ 432	$ (35)

(1) 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.

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

(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

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, 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	Years Ended December 31, 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, 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	Years Ended December 31, 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, 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 table below presents the components of our midstream segment margin. For the years ended December 31, 2018 and 2017, the amounts previously reported for fee-based and non-fee-based margin have been adjusted to reflect reclassification of certain contractual minimum fees from fee-based margin to non-fee-based margin in order to conform to the current period classification.

	Years Ended December 31,		
	2018	2017	Change
Gathering and processing fee-based revenues	$ 1,788	$ 1,690	$ 98
Non-fee based contracts and processing (excluding unrealized gains and losses)	589	477	112
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 $98 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 $79 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	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	$ 511	$ 415	$ 96
Transportation margin	1,233	990	243
Storage margin	211	214	(3)
Terminal Services margin	494	424	70
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 $96 million primarily due to a $106 million increase resulting from the commissioning of our fifth fractionator in July 2018 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 $70 million due to a $36 million increase resulting from a change in the classification of certain customer reimbursements previously recorded in operating expenses, a $23 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 gains of $355 million due to more favorable basis spreads; partially offset by an unfavorable inventory valuation adjustment of $54 million for the 2018 year as compared to a favorable inventory valuation adjustment of $82 million for the 2017 year; 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	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 valuation 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	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

The investment in USAC segment reflects the consolidated results of 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	(87)	(103)	16
Adjusted EBITDA related to unconsolidated affiliates	1	45	(44)
Other and eliminations	(2)	13	(15)
Segment Adjusted EBITDA	$ 76	$ 219	$ (143)

Amounts reflected in our all other segment during the periods presented above 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 impacts 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 our investment in PES primarily due to our 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.

<u>Liquidity and Capital Resources</u>

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

The Partnership currently expects capital expenditures in 2020 to be within the following ranges (excluding capital expenditures related to our investments in Sunoco LP and USAC:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 20	$ 30	$ 40	$ 45
Interstate transportation and storage [(1)]	100	125	140	145
Midstream	625	650	125	130
NGL and refined products transportation and services [(1)]	2,550	2,650	100	110
Crude oil transportation and services	500	525	165	175
All other (including eliminations)	25	50	75	80
Total capital expenditures	$ 3,820	$ 4,030	$ 645	$ 685

(1) Includes capital expenditures related to our proportionate ownership of the Bakken, Rover, and Bayou Bridge pipeline projects and our proportionate ownership of the Orbit Gulf Coast NGL export project.

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.

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally expect to fund growth capital expenditures with proceeds of borrowings under ETO credit facilities, along with cash from operations.

As of December 31, 2019, in addition to $253 million of cash on hand, we had available capacity under the ETO Credit Facilities of $1.71 billion. Based on our current estimates, we expect to utilize capacity under the ETO Credit Facilities, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2020; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

Sunoco 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, 2019, Sunoco LP had available borrowing capacity of $1.33 billion under its revolving credit facility and $21 million of cash and cash equivalents on hand.

In 2020, Sunoco LP expects to invest approximately $130 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

USAC currently plans to spend approximately $32 million in maintenance capital expenditures during 2020, including parts consumed from inventory.

Without giving effect to any equipment USAC may acquire pursuant to any future acquisitions, it currently has budgeted between $110 million and $120 million in expansion capital expenditures during 2020. As of December 31, 2019, USAC has binding commitments to purchase $49 million of additional compression units, all of which USAC expects to be delivered in 2020.

Cash Flows

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

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation, 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 acquisitions 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 we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of derivative 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, 2019

Cash provided by operating activities in 2019 was $8.25 billion and income from continuing operations was $5.19 billion. The difference between net income and cash provided by operating activities in 2019 primarily consisted of non-cash items totaling $3.27 billion offset by net changes in operating assets and liabilities of $479 million. The non-cash activity in 2019 consisted primarily of depreciation, depletion and amortization of $3.12 billion, impairment losses of $74 million, non-cash compensation expense of $111 million, equity in earnings of unconsolidated affiliates of $298 million, inventory valuation adjustments of $79 million, losses on extinguishment of debt of $2 million, and deferred income tax expense of $221 million. The Partnership also received distributions of $285 million from unconsolidated affiliates.

Year Ended December 31, 2018

Cash provided by operating activities in 2018 was $7.56 billion and income from continuing operations was $4.04 billion. The difference between net income and cash provided by operating activities in 2018 primarily consisted of non-cash items totaling $3.11 billion offset by net changes in operating assets and liabilities of $117 million. The non-cash activity in 2018 consisted primarily of depreciation, depletion and amortization of $2.84 billion, impairment losses of $431 million, non-cash compensation expense of $105 million, equity in earnings of unconsolidated affiliates of $344 million, inventory valuation adjustments of $85 million, losses on extinguishment of debt of $109 million and a deferred income tax expense of $8 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 $4.82 billion and income from continuing operations was $2.95 billion. The difference between net income and cash provided by operating activities in 2017 primarily consisted of non-cash items totaling $1.78 billion offset by net changes in operating assets and liabilities of $173 million. The non-cash activity in 2017 consisted primarily of depreciation, depletion and amortization of $2.54 billion, impairment losses of $1.04 billion, impairment in unconsolidated affiliates of $313 million, non-cash compensation expense of $99 million, equity in earnings of unconsolidated affiliates of $144 million, inventory valuation adjustments of $24 million, losses on extinguishment of debt of $42 million and a deferred income tax benefit of $1.84 billion. The Partnership also received distributions of $297 million from unconsolidated affiliates.

Investing Activities

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

Following is a summary of investing activities by period:

Year Ended December 31, 2019

Cash used in investing activities in 2019 was $6.12 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $5.86 billion. Additional detail related to our capital expenditures is provided in the table below. During 2019, we received $93 million of cash proceeds from the sale of a noncontrolling interest in a subsidiary and paid $7 million in cash for all other acquisitions. We received $54 million of cash proceeds from the sale of assets. The Partnership also received distributions of $98 million from unconsolidated affiliates.

Year Ended December 31, 2018

Cash used in investing activities in 2018 was $6.90 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $7.30 billion. Additional detail related to our capital expenditures is provided in the table below. We received $711 million of net cash proceeds related to the USAC acquisition and paid $429 million in cash for all other acquisitions. We received $87 million of cash proceeds from the sale of assets. The Partnership also received distributions of $69 million from unconsolidated affiliates.

Year Ended December 31, 2017

Cash used in investing activities in 2017 was $5.61 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $8.42 billion. Additional detail related to our capital expenditures is provided in the table below. We paid $280 million in cash related to the acquisition of PennTex's remaining noncontrolling interest and $303 million in cash for all other acquisitions. We received $2.00 billion in cash related to the Bakken equity sale to MarEn Bakken Company LLC, $1.48 billion in cash related to the Rover equity sale to Blackstone Capital Partners. We received $45 million of cash proceeds from the sale of assets. The Partnership also received distributions of $135 million from unconsolidated affiliates.

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, our proportionate share of the Orbit Gulf Coast NGL export project, and net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Year Ended December 31, 2019:			
Intrastate transportation and storage	$ 87	$ 37	$ 124
Interstate transportation and storage	239	136	375
Midstream	669	157	826
NGL and refined products transportation and services	2,854	122	2,976
Crude oil transportation and services	310	82	392
Investment in Sunoco LP	108	40	148
Investment in USAC	170	30	200
All other (including eliminations)	165	48	213
Total capital expenditures	$ 4,602	$ 652	$ 5,254
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 [(1)]	72	31	103
Investment in USAC	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 [(1)]	129	48	177
All other (including eliminations)	196	72	268
Total capital expenditures	$ 5,601	$ 479	$ 6,080

(1) 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 our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of common units outstanding.

Following is a summary of financing activities by period:

Year Ended December 31, 2019

Cash used in financing activities was $2.29 billion in 2019. During 2019, we received net proceeds of $780 million from the issuance of preferred units. Net proceeds from the offering were used to repay outstanding borrowings under the ETO Credit

Facilities, to fund capital expenditures and acquisitions, as well as for general partnership purposes. In 2019, we had a net increase in in our debt level of $4.38 billion. In 2019, we paid distributions of $6.28 billion to our partners and we paid distributions of $1.40 billion to noncontrolling interests. In addition, we received capital contributions of $348 million in cash from noncontrolling interests. During 2019, we incurred debt issuance costs of $117 million.

Year Ended December 31, 2018

Cash used in financing activities was $3.31 billion in 2018. During 2018, we received $58 million in net proceeds from common unit offerings and $867 million in net proceeds from the issuance of preferred units. Net proceeds from the offerings were used to repay outstanding borrowings under the ETO Credit Facility, to fund capital expenditures and acquisitions as well as for general partnership purposes. In 2018, we had a net increase in our debt level of $801 million. In 2018, we paid distributions of $4.56 billion to our partners and distributions of $1.17 billion to noncontrolling interests, including predecessor distributions. During 2018, we incurred debt issuance costs of $162 million, and our subsidiaries repurchased $300 million of common units in cash. In addition, we received capital contributions from noncontrolling interests of $649 million. Additionally, in 2018, our subsidiary received $465 million related to redeemable noncontrolling interests.

Year Ended December 31, 2017

Cash provided by financing activities was $572 million in 2017. We received $2.28 billion in net proceeds from common unit offerings, $1.48 billion in net proceeds from the issuance of preferred units and we received $333 million in net proceeds from predecessor equity offerings. Net proceeds from the offerings and issuances were used to repay outstanding borrowings under the ETO Credit Facility, to fund capital expenditures and acquisitions as well as for general partnership purposes. In 2017, we had a net decrease in our debt level of $421 million. In addition, we incurred debt issuance costs of $83 million. In 2017, we paid distributions of $3.47 billion to our partners and distributions of $714 million to noncontrolling interests, including predecessor distributions. In addition, we received capital contributions from noncontrolling interests of $1.21 billion.

Discontinued Operations

Cash flows from discontinued operations reflect cash flows related to Sunoco LP's retail divestment.

Year Ended December 31, 2019

There were no cash flows related to discontinued operations during 2019.

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.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31,	
	2019	2018
ETO Senior Notes	$ 36,118	$ 28,755
Transwestern Senior Notes	575	575
Panhandle Senior Notes	235	385
Bakken Senior Notes	2,500	—
Sunoco LP Senior Notes, Term Loan and lease-related obligations	2,935	2,307
USAC Senior Notes	1,475	725
Revolving credit facilities:		
ETO $2.00 billion Term Loan facility due October 2022	2,000	—
ETO $5.00 billion Revolving Credit Facility due December 2023	4,214	3,694
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	162	700
USAC $1.60 billion Revolving Credit Facility due April 2023	403	1,050
Bakken $2.50 billion Credit Facility due August 2019	—	2,500
Other long-term debt	2	7
Unamortized premiums, net of discounts and fair value adjustments	3	31
Deferred debt issuance costs	(276)	(221)
Total debt	50,346	40,508
Less: current maturities of long-term debt	12	2,655
Long-term debt, less current maturities	$ 50,334	$ 37,853

The terms of our consolidated indebtedness and that of our subsidiaries are described in more detail below and in Note 5 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

Recent Transactions

ETO January 2020 Senior Notes Offering and Redemption

On January 22, 2020, ETO completed a registered offering (the "January 2020 Senior Notes Offering") of $1.00 billion aggregate principal amount of the Partnership's 2.900% Senior Notes due 2025, $1.50 billion aggregate principal amount of the Partnership's 3.750% Senior Notes due 2030 and $2.00 billion aggregate principal amount of the Partnership's 5.000% Senior Notes due 2050, (collectively, the "Notes"). The Notes are fully and unconditionally guaranteed by the Partnership's wholly owned subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis.

Utilizing proceeds from the January 2020 Senior Notes Offering, ETO redeemed its $400 million aggregate principal amount of 5.75% Senior Notes due September 1, 2020, its $1.05 billion aggregate principal amount of 4.15% Senior Notes due October 1, 2020, its $1.14 billion aggregate principal amount of 7.50% Senior Notes due October 15, 2020, its $250 million aggregate principal amount of 5.50% Senior Notes due February 15, 2020, ET's $52 million aggregate principal amount of 7.50% Senior Notes due October 15, 2020 and Transwestern's $175 million aggregate principal amount of 5.36% Senior Notes due December 9, 2020.

ETO Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the "ETO Term Loan") providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

ET-ETO Senior Notes Exchange

In February 2019, ETO commenced offers to exchange all of ET's outstanding senior notes for senior notes issued by ETO (the "ET-ETO senior notes exchange"). Approximately 97% of ET's outstanding senior notes were tendered and accepted, and substantially all the exchanges settled on March 25, 2019. In connection with the exchange, ETO issued approximately $4.21 billion aggregate principal amount of the following senior notes:

- $1.14 billion aggregate principal amount of 7.50% senior notes due 2020;
- $995 million aggregate principal amount of 4.25% senior notes due 2023;
- $1.13 billion aggregate principal amount of 5.875% senior notes due 2024; and
- $956 million aggregate principal amount of 5.50% senior notes due 2027.

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.

Panhandle Senior Notes Redemption

In June 2019, Panhandle's $150 million aggregate principal amount of 8.125% senior notes matured and were repaid with borrowings under an affiliate loan agreement with ETO.

Bakken Senior Notes Offering

In March 2019, Midwest Connector Capital Company LLC, a wholly-owned subsidiary of Dakota Access, issued the following senior notes related to the Bakken pipeline:

- $650 million aggregate principal amount of 3.625% senior notes due 2022;
- $1.00 billion aggregate principal amount of 3.90% senior notes due 2024; and
- $850 million aggregate principal amount of 4.625% senior notes due 2029.

The $2.48 billion in net proceeds from the offering were used to repay in full all amounts outstanding on the Bakken credit facility and the facility was terminated.

Sunoco LP Senior Notes Offering

In March 2019, Sunoco LP issued $600 million aggregate principal amount of 6.00% senior notes due 2027 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP's existing borrowings under its credit facility. In July 2019, Sunoco LP completed an exchange of these notes for registered notes with substantially identical terms.

USAC Senior Notes Offering

In March 2019, USAC issued $750 million aggregate principal amount of 6.875% senior notes due 2027 in a private placement, and in December 2019, USAC exchanged those notes for substantially identical senior notes registered under the Securities Act. The net proceeds from this offering were used to repay a portion of USAC's existing borrowings under its credit facility and for general partnership purposes.

Credit Facilities and Commercial Paper

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 Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the "ETO Term Loan") providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

As of December 31, 2019, the ETO Term Loan had $2.00 billion outstanding and was fully drawn. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.78%.

ETO Five-Year Credit Facility

ETO's revolving credit facility (the "ETO Five-Year Credit Facility") allows for unsecured borrowings up to $5.00 billion and matures on 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, 2019, the ETO Five-Year Credit Facility had $4.21 billion outstanding, of which $1.64 billion was commercial paper. The amount available for future borrowings was $709 million after taking into account letters of credit of $77 million. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.88%.

ETO 364-Day Facility

ETO's 364-day revolving credit facility (the "ETO 364-Day Facility") allows for unsecured borrowings up to $1.00 billion and matures on November 27, 2020. As of December 31, 2019, the ETO 364-Day Facility had no outstanding borrowings.

Sunoco LP Credit Facility

As of December 31, 2019, the Sunoco LP Credit Facility had $162 million outstanding borrowings and $8 million in standby letters of credit. The amount available for future borrowings was $1.33 billion at December 31, 2019. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 3.75%.

USAC Credit Facility

As of December 31, 2019, USAC had $403 million of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2019, USAC had $1.20 billion of availability under its credit facility. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 4.31%.

Covenants Related to Our Credit Agreements

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 contain 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 1.250% 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 4.04 to 1 at December 31, 2019, 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.

Panhandle's restrictive covenants include restrictions on liens securing debt and guarantees and restrictions on mergers and on the sales of assets. A breach of any of these covenants could result in acceleration of Panhandle's debt.

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) 5.5 to 1 through the end of the fiscal quarter ending December 31, 2019 and (ii) 5.0 to 1.0 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 and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2019.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of December 31, 2019:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 50,619	$ 3,021	$ 7,204	$ 13,297	$ 27,097
Interest on long-term debt[(1)]	40,939	2,522	4,917	4,276	29,224
Payments on derivatives	401	150	251	—	—
Purchase commitments [(2)]	2,133	2,053	57	7	16
Transportation, natural gas storage and fractionation contracts	16	5	6	5	—
Operating lease obligations	1,548	98	166	140	1,144
Service concession arrangement[(3)]	379	15	30	32	302
Other[(4)]	190	25	48	40	77
Total[(5)]	$ 96,225	$ 7,889	$ 12,679	$ 17,797	$ 57,860

(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2019. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2019. To the extent interest rates change, our contractual obligations for interest payments will change. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for further discussion.

(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, 2019 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, AROs, 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 non-current deferred tax liabilities of $3.11 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

ETO Preferred Unit Distributions

Distributions on the Partnership's Series A, Series B, Series C, Series D and Series E preferred units declared and/or paid by the Partnership were as follows:

Period Ended	Record Date	Payment Date	Series A [1]	Series B [1]	Series C	Series D	Series E
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	—
March 31, 2019	May 1, 2019	May 15, 2019	—	—	0.4609	0.4766	—
June 30, 2019	August 1, 2019	August 15, 2019	31.2500	33.1250	0.4609	0.4766	0.5806 *
September 30, 2019	November 1, 2019	November 15, 2019	—	—	0.4609	0.4766	0.4750
December 31, 2019	February 3, 2020	February 18, 2020	31.2500	33.1250	0.4609	0.4766	0.4750

* Represent prorated initial distributions. Prorated initial distributions on the recently issued Series F and Series G preferred units will be payable in May 2020.

(1) Series A Preferred Units and Series B Preferred Unit distributions are paid on a semi-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, 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
March 31, 2019	May 7, 2019	May 15, 2019		0.8255
June 30, 2019	August 6, 2019	August 14, 2019		0.8255
September 30, 2019	November 5, 2019	November 19, 2019		0.8255
December 31, 2019	February 7, 2020	February 19, 2020		0.8255

USAC Cash Distributions

Subsequent to the Energy Transfer Merger and USAC Transactions described in Note 1 and Note 3, respectively, ETO owned approximately 39.7 million USAC common units and 6.4 million USAC Class B units. Subsequent to the conversion of the USAC Class B Units to USAC common units on July 30, 2019, ETO owns approximately 46.1 million USAC common units. As of December 31, 2019, USAC had approximately 96.6 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding IDRs.

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
March 31, 2019	April 29, 2019	May 10, 2019		0.5250
June 30, 2019	July 29, 2019	August 9, 2019		0.5250
September 30, 2019	October 28, 2019	November 8, 2019		0.5250
December 31, 2019	January 27, 2020	February 7, 2020		0.5250

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, 2019 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. Our midstream segment also generates revenues from the sale of residue gas and NGLs at the tailgate of our processing facilities primarily to affiliates and some third-party customers.

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.

Lease Accounting. At the inception of each lease arrangement, we determine if the arrangement is a lease or contains an embedded lease and review the facts and circumstances of the arrangement to classify lease assets as operating or finance leases under Topic 842. The Partnership has elected not to record any leases with terms of 12 months or less on the balance sheet.

Balances related to operating leases are included in operating lease ROU assets, accrued and other current liabilities, operating lease current liabilities and non-current operating lease liabilities in our consolidated balance sheets. Finance leases represent a small portion of the active lease agreements and are included in finance lease ROU assets, current maturities of long-term debt and long-term debt, less current maturities in our consolidated balance sheets. The ROU assets represent the Partnership's right to use an underlying asset for the lease term and lease liabilities represent the obligation of the Partnership to make minimum lease payments arising from the lease for the duration of the lease term.

Most leases include one or more options to renew, with renewal terms that can extend the lease term from one to 20 years or greater. The exercise of lease renewal options is typically at the sole discretion of the Partnership and lease extensions are evaluated on a lease-by-lease basis. Leases containing early termination clauses typically require the agreement of both parties to the lease. At the inception of a lease, all renewal options reasonably certain to be exercised are considered when determining the lease term. The depreciable life of lease assets and leasehold improvements are limited by the expected lease term.

To determine the present value of future minimum lease payments, we use the implicit rate when readily determinable. Presently, because many of our leases do not provide an implicit rate, the Partnership applies its incremental borrowing rate based on the information available at the lease commencement date to determine the present value of minimum lease payments. The operating and finance lease ROU assets include any lease payments made and exclude lease incentives.

Minimum rent payments are expensed on a straight-line basis over the term of the lease. In addition, some leases require additional contingent or variable lease payments, which are based on the factors specific to the individual agreement. Variable lease payments the Partnership is typically responsible for include payment of real estate taxes, maintenance expenses and insurance.

For short-term leases (leases that have term of twelve months or less upon commencement), lease payments are recognized on a straight-line basis and no ROU assets are recorded.

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 $4.90 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2019, approximately $380 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, 2019, the Partnership recorded the following impairments:

- A $12 million impairment was recorded related to the goodwill associated with the Partnership's Southwest Gas operations within the interstate segment primarily due to decreases in projected future revenues and cash flows. Additionally, the Partnership recorded a $9 million impairment related to the goodwill associated with the Partnership's North Central operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows.
- Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York.
- USAC also recognized a $6 million fixed asset impairment related to certain idle compressor assets.

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 assets were 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.
- 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.

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, 2019, 2018 and 2017 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 its indefinite-lived intangible assets during the fourth quarter of 2017 and recognized a total of $17 million in impairment charges on their contractual rights and liquor licenses primarily due to decreases in projected future revenues and cash flows from the date the intangible assets were 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 ARO 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 AROs as of December 31, 2019 and 2018, 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. ETC Sunoco 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, ETC Sunoco is legally or contractually required to abandon in place or remove the asset. We believe we may have additional AROs related to ETC Sunoco'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.

Other non-current assets on the Partnership's consolidated balance sheet included $31 million and $26 million of legally restricted funds for the purpose of settling AROs as of December 31, 2019 and 2018, respectively.

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 10 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" in this report.

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

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

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. The Partnership's estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded. The Partnership's consolidated balance sheet reflected $317 million in environmental accruals as of December 31, 2019.

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. ETO 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 $669 million have been included in ETO's consolidated balance sheet as of December 31, 2019. The state NOL carryforward benefits of $120 million ($95 million net of federal benefit) begin to expire in 2019 with a substantial portion expiring between 2033 and 2039. ETP Holdco has federal NOLs of $2.65 billion ($557 million in benefits) of which $1.10 billion will expire between 2031 and 2037. Any federal NOL generated in 2018 and future years can be carried forward indefinitely. Federal alternative minimum tax credit carryforwards of $15 million remained at December 31, 2019. We have determined that a valuation allowance totaling $62 million ($49 million net of federal income tax effects) is required for the state NOLs at December 31, 2019 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

Forward-Looking Statements

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

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins we realize for our gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;

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

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

Inflation

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET 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 table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Dollar amounts are presented in millions.

	December 31, 2019			December 31, 2018		
	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	1,483	$ —	$ —	468	$ —	$ —
Basis Swaps IFERC/NYMEX[1]	(35,208)	2	5	16,845	7	1
Options – Puts	—	—	—	10,000	—	—
Power (Megawatt):						
Forwards	3,213,450	6	8	3,141,520	6	8
Futures	(353,527)	1	2	56,656	—	—
Options – Puts	51,615	1	—	18,400	—	—
Options – Calls	(2,704,330)	1	—	284,800	1	—
Crude (MBbls) – Futures	—	—	—	—	—	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(18,923)	(35)	15	(30,228)	(52)	13
Swing Swaps IFERC	(9,265)	—	4	54,158	12	—
Fixed Swaps/Futures	(3,085)	(1)	1	(1,068)	19	1
Forward Physical Contracts	(13,364)	3	3	(123,254)	(1)	32
NGL (MBbls) – Forwards/Swaps	(1,300)	(18)	18	(2,135)	67	67
Crude (MBbls) – Forwards/Swaps	4,465	13	2	20,888	(60)	29
Refined Products (MBbls) – Futures	(2,473)	(2)	16	(1,403)	(8)	6
Corn (thousand bushels)	(1,210)	—	—	(1,920)	—	1
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(31,780)	1	7	(17,445)	(4)	—
Fixed Swaps/Futures	(31,780)	23	7	(17,445)	(10)	6

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

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

Interest Rate Risk

As of December 31, 2019, we and our subsidiaries had $7.38 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $74 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, 2019	December 31, 2018
March 2019	Pay a floating rate and receive a fixed rate of 1.42%	$ —	$ 300
July 2019 [(2)]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	—	400
July 2020 [(2)(3)]	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	400
July 2022 [(2)]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	400	—

(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.

(3) The July 2020 interest rate swaps were terminated in January 2020.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains (losses) on interest rate derivatives) of $327 million as of December 31, 2019. 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 ETP LLC, 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 ETP LLC, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2019.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer Operating, L.P. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of ETP LLC, 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, 2019.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2019 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner, Energy Transfer Partners GP, L.P. (“ETP GP”), manages and directs all of our activities. The activities of ETP GP are managed and directed by its general partner, ETP LLC, which we refer to in this Item as “our General Partner.” Our officers and directors are officers and directors of ETP LLC. ET, as the sole member of ETP LLC, is entitled under the limited liability company agreement of ETP LLC to appoint all of the directors of ETP LLC. This agreement provides that the Board of Directors of ETP LLC shall consist of not more than 13 persons, at least three of whom are required to qualify as independent directors.

As of January 1, 2020, our Board of Directors is comprised of six persons, three of whom qualified as “independent” under the NYSE’s corporate governance standards. Our Board of Directors determined that Messrs. Smith, Skidmore and Williams all met the NYSE’s independence requirements. Our current directors who are not independent consist of Kelcy L. Warren, ETP LLC’s Chief Executive Officer, Matthew S. Ramsey, ETP LLC’s President and Chief Operating Officer and Marshall S. McCrea, III, ETP LLC’s Chief Commercial Officer.

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

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

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

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

Corporate Governance

The Board of Directors has adopted both a Code of Business Conduct and Ethics applicable to our directors, officers and employees, and Corporate Governance Guidelines for directors and the Board. Current copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and charters of the Audit and Compensation Committees of our Board of Directors are available on our website at www.energytransfer.com.

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 2019, our CEO provided to the NYSE the annual CEO certification regarding our compliance with the NYSE corporate governance listing standards.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Partnership and its Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to the Partnership. Pursuant to the terms of our Partnership Agreement, any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders. These duties are limited by our Partnership Agreement (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE's standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407 (d)(5) of Regulation S-K. The Board has determined that based on relevant experience, Audit Committee member David K. Skidmore qualified as Audit Committee financial expert during 2019. A description of the qualifications of Mr. Skidmore may be found elsewhere in this Item under "Directors and Executive Officers of our General Partner."

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

Compensation and Nominating/Corporate Governance Committees

We are not required under NYSE rules to appoint a compensation committee or a nominating/corporate governance committee because we are a limited partnership; however, our Board of Directors previously established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. Following the Energy Transfer Merger, the duties of the ETO compensation committee have been delegated to the Compensation Committee of ET.

Code of Business Conduct and Ethics

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

Meetings of Non-management Directors and Communications with Directors

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

We have established a procedure by which interested parties may communicate directly with the Board of Directors, any committee of the Board, any independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person or entity to the attention of our General Counsel at Energy Transfer Operating, L.P., 8111 Westchester Drive, Suite 600, Dallas, Texas 75225 or generalcounsel@energytransfer.com. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Directors and Executive Officers of 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 21, 2020. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	64	Chief Executive Officer and Chairman of the Board of Directors
Matthew S. Ramsey	64	Director, President and Chief Operating Officer
Thomas E. Long	63	Chief Financial Officer
Marshall S. (Mackie) McCrea, III	60	Director and ET President and Chief Commercial Officer
James M. Wright, Jr.	51	General Counsel
A. Troy Sturrock	49	Senior Vice President, Controller and Principal Accounting Officer
David K. Skidmore	64	Director
W. Brett Smith	60	Director
William P. Williams	82	Director

Messrs. Warren, McCrea and Ramsey also serve as directors of ET's general partner. Mr. Ramsey also serves as chairman of the board of the general partner of Sunoco LP, and Mr. Long serves as a director of the board 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 is the Chief Executive Officer and Chairman of the Board of Directors of the general partner of ETO. Mr. Warren also serves as Chairman of the Board of Directors of ET's general partner. 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 in 2004, Mr. Warren co-founded the entities that acquired and operated the midstream assets that were contributed in the merger. From 1996 to 2000, Mr. Warren served as a Director of Crosstex Energy, Inc. and from 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. The member of our general partner selected Mr. Warren to serve as a director and as Chairman because he is the Partnership'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.

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 was named President and Chief Operating Officer of ETO's general partner in November 2015. He became the Chief Operating Officer of ET's general partner in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. 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 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 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 E. Long. Mr. Long has served as the Chief Financial Officer of our general partner since February 2016 and a director of our general partner since April 2019. He also joined the Board of Directors of ET's general partner in April 2019. 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, Colorado. 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 was appointed as a director of the general partner of ETO and as a a director of ET's general partner 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 member 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.

James M. Wright, Jr. Mr. Wright was elected General Counsel of our general partner in December 2015. He became Executive Vice President - Legal and Chief Compliance Officer of ET's general partner in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. Mr. Wright has been a part of the Energy Transfer legal team with increasing levels of responsibility since July 2005, and served as its Deputy General Counsel from May 2008 to December 2015. Prior to joining Energy Transfer, Mr. Wright gained significant experience at Enterprise Products Partners, L.P., El Paso Corp., Sonat Exploration Company and KPMG Peat Marwick LLP. Mr. Wright earned a Bachelor of Business Administration degree in Accounting and Finance from Texas A&M University and a JD from South Texas College of Law.

A. Troy Sturrock. Mr. Sturrock 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 since 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. He became Senior Vice President, Controller and Principal Accounting Officer of ET's general partner in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. 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.

David K. Skidmore. Mr. Skidmore has served as a director of our general partner since March 2013. He has been Vice President of Ventex Oil & Gas, Inc. since 1995 and has been actively involved in exploration and production throughout the Gulf Coast and mid-Continent regions for over 35 years. He founded Skidmore Exploration, Inc. in 1981 and has been an independent oil and gas producer since that time. From 1977 to 1981, he worked for Paraffine Oil Corporation and Texas Oil & Gas in Houston. He holds BS degrees in both Geology and Petroleum Engineering, is a Certified Petroleum Geologist and Registered Professional Engineer, and active member of the AAPG, and SPE. Mr. Skidmore is also a member of ETO's audit committee. Mr. Skidmore was selected to serve as a director because of his continual involvement in geological, geophysical, legal, engineering and accounting aspects of an active oil and gas exploration company. As an energy professional, active oil and gas producer and successful business owner, Mr. Skidmore possesses valuable first-hand knowledge of the energy transportation business and market conditions affecting its economics.

W. Brett Smith. Mr. Smith was appointed to the Board of Directors of our general partner in February 2018 and has served on the audit committee since that time. He has served as President and Managing Partner of Rubicon Oil & Gas, LLC since October 2000. He has also served as President of Rubicon Oil & Gas II, LP since May 2005, President of Quientesa Royalty LP since February 2005 and President of Action Energy LP since October 2008. Mr. Smith was President of Rubicon Oil & Gas, LP from October 2000 to May 2005. For more than 30 years Mr. Smith has been active in assembling exploration prospects in the Permian Basin, Oklahoma, New Mexico and the Rocky Mountain areas. Mr. Smith previously served on the board of directors of Sunoco LP and was a member of its audit and compensation committees. Mr. Smith was selected to serve on the Board of Directors of our general partner based on his experience as an executive in the oil and gas exploration and production business, which gives him unique insight into the Partnership's business, as well as his recent experience on the board of another publicly traded limited partnership.

William P. Williams. Mr. Williams began his career in the oil and gas industry in 1967 with Texas Power and Light Company as Manager of Pipeline Construction for Bi-Stone Fuel Company, a predecessor of Texas Utilities Fuel Company. In 1980, he was employed by Endevco as Vice President of Pipeline and Plant Construction, Engineering, and Operations. Prior to Endevco, he worked for Cornerstone Natural Gas followed by Vice President of Engineering and Operations at Energy Transfer Partners, L.P., ending his career as Vice President of Measurement on May 1, 2011. The member of our general partner selected Mr. Williams due to his experience in the pipeline industry and his familiarity with our business.

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. Our General Partner and its affiliates performing services for the Partnership are reimbursed at cost for all expenses incurred on behalf of the Partnership, including the costs of employee compensation allocable to, but not paid directly by, the Partnership, if any, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Our employees are employed by our subsidiaries, and thus, our General Partner does not incur additional reimbursable costs.

Our General Partner is ultimately controlled by the general partner of ET, which general partner entity is partially-owned by certain of our current and prior named executive officers. We pay quarterly distributions to our General Partner in accordance with our Partnership Agreement with respect to its ownership of a general partner interest and the incentive distribution rights specified in our Partnership Agreement. The amount of each quarterly distribution that we must pay to our General Partner is based solely on the provisions of our Partnership Agreement, which agreement specifies the amount of cash we distribute to our General Partner based on the amount of cash that we distribute to our limited partners each quarter. Accordingly, the cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner's executive officers. Our General Partner's distribution rights are described in detail in Note 7 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.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner. Our General Partner is owned by ET.

Compensation Discussion and Analysis

Named Executive Officers

ETO 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 ETO's management functions. In addition, our executive officers are also executive officers of ET. The board of directors of our General Partner does not have a separate compensation committee. Therefore, we do not administer any policies or programs relating to the compensation of ET's named executive officers. The compensation of our executive officers is administered by the compensation committee of the board of directors of ET's general partner (the "ET Compensation Committee"). This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of ET's General Partner as set forth below. Compensation amounts discussed herein include all compensation paid to ET's named executive officers, including amounts attributable to services performed for us. The persons we refer to in this discussion as the "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; and
- Thomas P. Mason, Executive Vice President, General Counsel and President — LNG.

ET's General Partner's Philosophy for Compensation of Executives

In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based 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 its executive officers, including the named executive officers that provides for a slightly below the median market annual base compensation (i.e. approximately the 30^{th} to 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 executive officers, including the 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 executive officers awards, including awards to the named executive officers, 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.

ET's General Partner 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. ET's General Partner 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 ET's General Partner places on aligning the interests of its named executive officers with those of unitholders.

As discussed below, the ET Compensation Committee, the ETO Compensation Committee (prior to the Energy Transfer Merger) is responsible for the compensation policies and compensation level of our executive officers, including the named executive officers. In this discussion, we refer to ET Compensation Committee and the ETO Compensation Committee prior to the Energy Transfer Merger as the "ET Compensation Committee."

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

Compensation Philosophy

ET's 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, 2019, the compensation paid to the 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 ET's 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 the executive officers of its General Partner, 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, 2019. 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 the 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 entities from an energy industry perspective. During 2019, 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 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 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 peers. This decision was 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 focus 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	• Marathon Petroleum Corporation
• Enterprise Products Partners, L.P.	• Kinder Morgan, Inc.
• Plains All American Pipeline, L.P.	• The Williams Companies, Inc.
• Valero Energy Corporation	• Phillips 66

The compensation analysis provided by Longnecker in 2019 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 public disclosures of peer companies, including 10-K and proxy data and published survey data from multiple sources that are relevant to ET's peer group, industry, financial size and operational breadth. The Longnecker review process also included significant engagement with management to fully understand job scope, responsibilities and roles of each of the executive officers, which discussions allow Longnecker the ability to completely evaluate specific aspects of an executive officer's position to allow for more accurate benchmarking.

Following Longnecker's 2019 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 could be considered moving forward to allow the Partnership to continue to achieve its targeted percentiles on base compensation and incentive compensation (short and long-term). Those adjustments are being considered by the ET Compensation Committee and management, and will, as deemed appropriate, be implemented.

In addition to the information received as part of Longnecker's 2019 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.

In addition to the 2019 compensation analysis for executive officers, Longnecker also provided advice and feedback on certain other matters, including the appropriateness, targets and composition of the annual equity award pools and the annual bonus awards under the Energy Transfer Annual Bonus Plan (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 30th to 40th percentile of market) and are determined by the ET Compensation Committee after taking into account the recommendations of Mr. Warren.

During the 2019 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 3.5% increase to the base salary of Mr. McCrea to $1,114,555 from its prior level of $1,076,865; an approximately 10% base salary increase to Mr. Long to $600,000 from its prior level of $545,900; a 3.5% base salary increase to Mr. Ramsey to $696,598 from its prior level of $673,041; and a 3.5% base salary increase to Mr. Mason to $631,396 from its prior level of $610,044. 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 2019.

The 3.5% increase to Messrs. McCrea, Ramsey and Mason reflected a base salary increase substantially the same as the annual merit increase pool set for all employees of ET and its affiliates for 2019. The 10% increase for Mr. Long was undertaken to continue the process to more closely align Mr. Long with the targeted total compensation of similarly situated officers of peer group companies and the market data.

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 2019, 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 and Mason 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 2018 period.

In February 2020, the ET Compensation Committee certified 2019 performance results under the Bonus Plan, which resulted in a bonus payout of 100% of the bonus pool target, which reflected achievement of 100.3% of the Adjusted EBITDA Target, 99.7% of the DCF Target and 101.6% or $13 million under the Department Budget Target. Based on the approved results, the ET Compensation Committee approved a cash bonus relating to the 2019 calendar year to Messrs. McCrea, Long, Ramsey, and Mason in the amounts of $1,750,817, $900,000, $889,100 and $805,900, respectively.

In approving the 2019 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 2019 and the individual performances of each of the named executive officers. The cash bonuses awarded to each of the named executive officers for 2019 performance were materially consistent with their applicable bonus pool targets, except Mr. Long who received approximately 120% of his targeted bonus award in consideration of (i) a recommendation to increase his award by Mr. Warren in recognition of Mr. Long's efforts on certain key financial objectives during 2019 and (ii) a further alignment of Mr. Long with the targeted total compensation of similarly situated officers of peer group companies and the market data. As with base salary and equity awards, Mr. Warren does not accept or receive an annual bonus.

Equity Awards. ET maintains and operates (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"); the (iii) Energy Transfer LP 2015 Long-Term Incentive Plan (the "2015 Plan"); (iv) the Amended and Restated Energy Transfer LP Long-Term Incentive Plan (the "ET 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. ET has generally used time-vested restricted units and/or phantom units as the vehicle for its annual equity awards to eligible employees, including the named executive officers.

For 2019, 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. The targets of the named executive officers were the same as the prior year's targets.

The annual long-term incentive targets are used as the basis to determine the target number of units to be awarded to the eligible participant, including the named executive officers. A multiple of base salary is used to set the pool target, that number is then divided by a weighted average price determined by considering ET's modified total unitholder return "(TUR") performance as measured against the average return of ET's identified peer group over defined time periods. For purposes of establishing an initial price, ET utilizes a 60 trading-day trailing weighted average price of ET common units prior to November 1, 2019. This average trading price is then subject to adjustment when ET's TUR is more than 5% greater or less than that of its identified peer group. If the TUR analysis yields a result that is within 5% percent of its identified peer group, the ET Compensation Committee will simply use the 60 trading day trailing weighted average price divided by the applicable salary multiple to establish a target pool for each eligible participant, including the named executive officers. If ET's TUR is outside of the 5% deviation, the 60 trading day trailing weighted average will be adjusted up or down based on ET's performance as compared to the identified group. For 2019, the peer group included the following:

- Enterprise Products Partners, L.P.
- The Williams Companies, Inc.
- Phillips 66
- Kinder Morgan, Inc.
- Plains All American Pipeline, L.P.
- MPLX LP

For 2019, the Partnership's TUR underperformed the identified peer group based on the average of the identified three comparison periods: (i) year-to-date 2019, (ii) trailing twelve months, and (iii) full-year 2018. Consequently, the 2019 long-term incentive base price was increased to reduce the total available restricted pool by approximately 13%.

In December 2019, the ET Compensation Committee in consultation with Mr. Warren approved grants of phantom unit awards to Messrs. McCrea, Long, Ramsey and Mason of 682,400 units, 215,000 units, 189,600 units and 214,800 units, respectively. As with base salary and annual bonus, Mr. Warren does not accept or receive annual long-term incentive awards. Mr. Long's award of 215,000 units represents an increase of approximately 30% over his pool target number. The increase for Mr. Long reflected (i) a recommendation to increase his award by Mr. Warren in recognition of Mr. Long's efforts on certain key financial objectives during 2019 and (ii) a further alignment of Mr. Long with the targeted total compensation of similarly situated officers of peer group companies and the market data.

As more fully described below in the section titled *Affiliate and Subsidiary Equity Awards*, for 2019, in discussions between the General Partner, the ET Compensation Committee and the compensation committee of the general partner of Sunoco LP, it was determined that for 2019 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 2019 long-term awards were allocated approximately 80% to the ET Incentive Plans and approximately 20% to the 2018 Sunoco LP Plan. The awards of Messrs. McCrea and Mason for 2019 were allocated entirely to the ET Incentive Plans. 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. For purposes of establishing a pool value for awards to eligible participants, including Messrs. Ramsey and Long, Sunoco LP utilized the same practices in terms of utilizing a peer group TUR analysis to set a grant date valuation.

The restricted unit awards granted in 2019 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 2019 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 awards 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 award agreements for the restricted units awarded in 2019, 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 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 for ET and ETO during 2019, 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 2019 approved grants of restricted unit awards to Messrs. Long and Ramsey of 19,500 and 22,600 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.

Unit Ownership Guidelines. The Board of Directors of ET's 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, were 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 8 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

We do not have a compensation committee and have not since the time of the Energy Transfer Merger. Messrs. Anderson, Grimm and Washburne are the members of the ET Compensation Committee. During 2019, no member of the ET Compensation Committee was an officer or employee of ET, ETO or any of our subsidiaries or served as an officer of any company with respect to which any named 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.

Board Report on Compensation

Following the Energy Transfer Merger, the duties of the ETO Compensation Committee have been delegated to the ET Compensation Committee. The board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management. 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 Board of Directors of Energy Transfer Partners, L.L.C., the
general partner of Energy Transfer Partners GP, L.P., the
general partner of Energy Transfer Operating, L.P.

Kelcy L. Warren
Matthew S. Ramsey
Marshall S. (Mackie) McCrea, III
David K. Skidmore
W. Brett Smith
William P. Williams

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 ($)	Bonus ($)	Equity Awards [(1)] ($)	Non-Equity Incentive Plan Compensation[(2)] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation[(3)] ($)	Total ($)
Kelcy L. Warren [(4)]	2019	$ 6,156	$ —	$ —	$ —	$ —	$ —	$ 6,156
Chief Executive Officer	2018	6,138	—	—	—	—	—	6,138
	2017	5,926	—	—	—	—	—	5,926
Thomas E. Long	2019	570,869	—	3,352,795	900,000	—	21,544	4,845,208
Chief Financial Officer	2018	537,338	1,000,000	4,251,335	800,000	—	21,294	6,609,967
	2017	480,846	—	2,519,954	625,100	—	18,320	3,644,220
Marshall S. (Mackie) McCrea, III	2019	1,094,260	—	8,734,720	1,750,817	—	21,544	11,601,341
President and Chief Commercial Officer	2018	1,059,976	—	7,834,782	1,866,000	—	19,362	10,780,120
	2017	1,027,846	—	9,033,341	1,644,554	—	16,834	11,722,575
Matthew S. Ramsey	2019	683,913	—	3,123,186	889,100	—	19,544	4,715,743
Chief Operating Officer	2018	662,486	—	2,818,415	900,000	—	19,294	4,400,195
	2017	642,404	—	3,763,893	835,125	—	18,618	5,260,040
Thomas P. Mason	2019	619,899	—	2,749,440	805,900	—	19,544	4,194,783
Executive Vice President, General Counsel and President – LNG	2018	600,477	—	2,466,882	858,700	—	19,294	3,945,353
	2017	582,275	—	2,816,048	756,958	—	18,618	4,173,899

(1) 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.

(2) ET maintains the Bonus Plan which provides for discretionary bonuses. Awards 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 2019 reflect cash bonuses approved by the ET Compensation Committee in February 2020 that are expected to be paid on or before March 15, 2020.

(3) The amounts reflected for 2019 in this column include (i) matching contributions to the ET 401(k) Plan made on behalf of the named executive officers of $14,000 each for Messrs. Long, McCrea, Ramsey and Mason, (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 2019, distribution payments in connection with distribution equivalent rights totaled $796,382 for Mr. Long, $2,178,361 for Mr. McCrea, $857,108 for Mr. Ramsey, and $756,879 for Mr. Mason.

(4) 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 in 2019

Name	Grant Date	All Other Unit Awards: Number of Units (#)	Grant Date Fair Value of Unit Awards [1]
ET Unit Awards:			
Kelcy L. Warren	N/A	—	$ —
Thomas E. Long	12/16/2019	215,000	2,752,000
Marshal S. (Mackie) McCrea, III	12/16/2019	682,400	8,734,720
Matthew S. Ramsey	12/16/2019	189,600	2,426,880
Thomas P. Mason	12/16/2019	214,800	2,749,440
Sunoco LP Unit Awards:			
Thomas E. Long	12/16/2019	19,500	600,795
Matthew S. Ramsey	12/16/2019	22,600	696,306

(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 8 to our consolidated financial statements.

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 2019 Fiscal Year-End

		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	12/16/2019	215,000	2,758,450
	12/18/2018	136,475	1,750,974
	10/19/2018	115,200	1,478,016
	12/20/2017	121,074	1,553,379
	12/29/2016	30,235	387,918
	12/9/2015	14,227	182,535
	12/4/2015	5,739	73,635
Marshal S. (Mackie) McCrea, III	12/16/2019	682,400	8,755,192
	12/18/2018	605,740	7,771,644
	12/20/2017	537,379	6,894,573

	12/29/2016	172,231		2,209,729
	12/9/2015	94,855		1,216,987
	12/4/2015	47,816		613,480
Matthew S. Ramsey	12/16/2019	189,600		2,432,568
	12/18/2018	168,260		2,158,776
	12/20/2017	223,908		2,872,740
	12/29/2016	73,440		942,235
	12/9/2015	59,282		760,592
Thomas P. Mason	12/16/2019	214,800		2,755,884
	12/18/2018	190,640		2,445,911
	12/20/2017	135,300		1,735,899
	12/29/2016	40,645		521,474
	12/9/2015	22,391		287,277
	12/4/2015	11,287		144,812
Sunoco LP Unit Awards:				
Thomas E. Long	12/16/2019	19,500	$	596,700
	12/19/2018	19,325		591,345
	12/21/2017	17,097		523,168
	12/29/2016	8,884		271,850
	12/16/2015	5,650		172,890
Matthew S. Ramsey	12/16/2019	22,600		691,560
	12/19/2018	23,825		729,045
	1/2/2015	814		24,908
Thomas P. Mason	12/21/2017	19,106		584,644
	12/29/2016	9,320		285,192
	12/16/2015	7,410		226,752

(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 2022 and 40% in December 2024 for awards granted in December 2019. 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;
- 100% in December 2021 for the remaining outstanding portion of awards granted in December 2016; and
- 100% in December 2020 for the remaining outstanding portion of awards granted in December 2015.

(3) Market value was computed as the number of unvested awards as of December 31, 2019 multiplied by the closing price of respective common units of ET and Sunoco LP.

Units Vested in 2019

	Unit Awards	
Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($) [(1)]
ET Unit Awards:		
Kelcy L. Warren	N/A	$ —
Thomas E. Long	55,839	647,730
Marshall S. (Mackie) McCrea, III	327,520	3,799,236
Matthew S. Ramsey	110,161	1,277,868
Thomas P. Mason	85,300	989,482
Sunoco LP Unit Awards:		
Thomas E. Long	13,326	401,779
Matthew S. Ramsey	299	9,033
Thomas P. Mason	13,980	421,497

(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 October 20108 equity 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 approval of the Special Bonus was conditioned upon entry by Mr. Mason into a Retention Agreement (the "Retention Agreement") which provided certain requirements for continued employment, including the following requirements that are still in effect: (i) 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 (ii) if, after the fourth (4^{th}) anniversary but prior to the fifth (5^{th}) 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. Warren, the Chairman and Chief Executive Officer and the annual total compensation of our employees.

For the 2019 calendar year:

The annual total compensation of Mr. Warren, as reported in the Summary Compensation Tables of this Item 11was $6,156; and

For 2019, the median total compensation of the employees supporting ETO (other than Mr. Warren) was $124,622, which amount was updated from 2017 for the designated "median employee."

Based on this information, for 2019 the ratio of the annual total compensation of Mr. Warren to the median of the annual total compensation of the 8,256 employees supporting ETO as of December 31, 2019 was approximately 1 to 20 as Mr. Warren has voluntarily elected not to accept any salary, bonus or equity incentive compensation (other than a salary of $1.00 per year plus an amount sufficient to cover his allocated employee premium contributions for health and welfare benefits).

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, 2019, the applicable employee populations consisted of 8,256 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 2018 or 2019 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 2019, updated with compensation of the "median employee" as reflected in our payroll records as reported on Form W-2 for 2019.
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 2019 resulting in an annual compensation of $124,622. 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 $10,989) and the employee's 401(k) matching contribution and profit sharing contribution (estimated at $6,040 per employee, includes $3,775 per employee on average matching contribution and $2,265 per employee on average profit sharing contribution (employees earning over $175,000 in base are ineligible for profit sharing)).
5. With respect to Mr. Warren, we used the amount reported in the "Total" column of our 2019 Summary Compensation Table under this Item 11.

Director Compensation

In 2019, the compensation arrangements for outside directors included a $100,000 annual retainer for services on the board. If a director served on the Audit Committee, such director would receive an annual cash retainer of $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 retainer of $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 Conflicts Committee assignment.

The outside directors of our General Partner are also entitled to an annual restricted unit 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 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 2019 is reflected in the following table:

Name	Fees Paid in Cash[(1)] ($)	Unit Awards[(2)] ($)	All Other Compensation ($)	Total ($)
David K. Skidmore	125,000	99,998	—	224,998
W. Brett Smith	115,000	99,998	—	214,998
William P. Williams	115,000	99,998	—	214,998

(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 or ETO common units (prior to the Energy Transfer Merger), accordingly, as of the grant date.

As of December 31, 2019, Mr. Skidmore had 23,136 unvested ET restricted units outstanding, Mr. Smith had 10,747 unvested ET restricted units outstanding and Mr. Williams had 21,243 unvested ET restricted units outstanding.

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

Equity Compensation Plan Information

The Partnership does not currently have any equity compensation plans. In connection with the Energy Transfer Merger in October 2018, all of the Partnership's equity compensation plans, as well as the Partnership's obligations under those plans, were assumed by ET.

Energy Transfer Operating, L.P. Units

All of the Partnership's common units are owned by ET and its subsidiaries as of December 31, 2019. In addition, the Partnership has Class K, Class L and Class M units, all of which are held by wholly-owned subsidiaries of the Partnership.

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

For a discussion of director independence, see Item 10. "Directors, Executive Officers and Corporate Governance."

As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The Partnership's board of directors makes the determinations as to whether there exists a related-party transaction in the normal course of reviewing transactions for approval as the Partnership's board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors' approval is sought by the Partnership's management. In addition, the Partnership's board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership's board makes those determinations in light of its contractually-limited fiduciary duties to the Unitholders. The Partnership Agreement provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all the partners of the Partnership and not a breach by the General Partner or its Board of Directors of any duties they may owe the Partnership or the Unitholders (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

ET owns directly and indirectly the general partner interest in ETP GP and all of the outstanding ETO Common Units.

See discussion in Note 15 to our consolidated financial statements, included in "Item 8. Financial Statements and Supplementary Data" for a discussion of our related party transactions.

Class M Units

On July 1, 2019, ETO issued a total of 220.5 million units of a new class of limited partner interests titled Class M Units to ETP Holdco, a wholly-owned subsidiary of the Partnership, in exchange for the contribution of ETP Holdco's equity ownership interest in PEPL to the Partnership.

The Class M Units generally do not have any voting rights. The Class M Units are entitled to quarterly cash distributions of $0.20 per Class M Unit. Distributions shall be paid quarterly, in arrears, within 45 days after the end of each quarter. As the Class M Units are owned by a wholly-owned subsidiary, the cash distributions on those units are 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,	
	2019	2018
Audit fees[1]	$ 10.8	$ 11.1
Audit related fees	0.1	0.5
Tax fees[2]	—	0.1
Total	$ 10.9	$ 11.7

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

(2) Includes fees in 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 2019 and 2018 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

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 January 25, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Regency Energy Partners LP, Regency GP LP and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on January 26, 2015).
2.2	Amendment No. 1 to Agreement and Plan of Merger, dated as of February 18, 2015, by and among Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., Rendezvous I LLC, Rendezvous II LLC, Regency Energy Partners LP, Regency GP LP, ETE GP Acquirer LLC and, solely for purposes of certain provisions therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.2 to Registrant's Form 8-K filed on February 19, 2015).
2.3	Contribution Agreement, dated October 24, 2016 by and among Energy Transfer Partners, L.P. and NGP X US Holdings, LP, PennTex Midstream Partners, LLC, MRD Midstream LLC, WHR Midstream LLC and certain individual investors and managers named therein (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed October 26, 2016).
2.4	Membership Interest Purchase Agreement, dated as of August 2, 2016, by and between Bakken Holdings Company LLC and MarEn Bakken Company LLC (incorporated by reference to Exhibit 2.2 to the Registrant's Form 10-Q for the quarter ended September 30, 2016).
2.5	First Amendment, dated December 14, 2016, to the Membership Interest Purchase Agreement, dated as of August 2, 2016, by and between Bakken Holdings Company LLC and MarEn Bakken Company LLC (incorporated by reference to Exhibit 2.12 to the Registrant's Form 10-K for the year ended December 31, 2016).
2.6	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 filed November 21, 2016).
2.7	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 filed December 21, 2016).
2.8	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 the Registrant's Form 8-K filed January 16, 2018).
2.9	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 the Registrant's Form 8-K filed January 16, 2018).
2.10	Contribution Agreement, dated as of July 30, 2017, by and among Energy Transfer Interstate Holdings, LLC, ET Rover Pipeline LLC and BCP Renaissance, L.L.C. (incorporated by reference to Exhibit 2.1 to the Registrant's Form 8-K filed August 2, 2017).
2.11	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 to the Form 8-K filed August 3, 2018).
3.1	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P. (formerly known as Sunoco Logistics Partners L.P.) (incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on April 28, 2017).
3.2	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.5 to the Registrant's Form 10-Q for the quarter ended May 31, 2007).
3.2.1	Amendment No. 2, dated March 26, 2012, to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P., dated as of April 17, 2007 (incorporated by reference to Exhibit 3.2 to Registrant's Form 8-K filed on March 28, 2012).
3.3	Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed August 10, 2010).

Exhibit Number	Description
3.3.1	Amendment No. 1, dated March 26, 2012, to the Fourth Amended and Restated Limited Liability Company Agreement of Energy Transfer Partners, L.L.C., dated as of August 10, 2010 (incorporated by reference to Exhibit 3.3 to Registrant's Form 8-K filed on March 28, 2012).
3.4	Certificate of Limited Partnership of Sunoco Logistics Partners L.P. (incorporated by reference to Exhibit 3.1 to Form S-1 filed October 22, 2001).
3.4.1	Amendment to the Certificate of Limited Partnership of Sunoco Logistics Partners L.P. dated as of August 28, 2015 (incorporated by reference to Exhibit 3.1 of Form 8-K filed September 1, 2015).
3.4.2	Amendment to the Certificate of Limited Partnership of Sunoco Logistics Partners L.P. dated as of April 28, 2017 (incorporated by reference to Exhibit 3.3 to the Registrant's Form 8-K filed April 28, 2017).
3.5	Certificate of Formation of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.13 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).
3.5.1	Certificate of Amendment of Energy Transfer Partners, L.L.C. (incorporated by reference to Exhibit 3.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).
3.6	Restated Certificate of Limited Partnership of Energy Transfer Partners GP, L.P. (incorporated by reference to Exhibit 3.14 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).
3.7	Certificate of Merger of Streamline Merger Sub, LLC, with and into Energy Transfer Partners, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed October 19, 2018).
3.8	Fifth Amended and Restated Agreement of Limited Partnership of Energy Transfer Operating, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed October 19, 2018).
3.8.1	Amendment No. 1, dated December 31, 2018, to Fifth Amended and Restated Agreement of Limited Partnership of Energy Transfer Operating, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed January 4, 2019).
3.8.2	Amendment No. 2, dated as of April 25, 2019, to Fifth Amended and Restated Agreement of Limited Partnership of Energy Transfer Operating, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed April 25, 2019).
3.8.3	Amendment No. 3, dated as of July 1, 2019, to Fifth Amended and Restated Agreement of Limited Partnership of Energy Transfer Operating, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed July 2, 2019).
4.1	Registration Rights Agreement, dated April 30, 2013, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed on May 1, 2013).
4.2	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed January 19, 2005).
4.3	Form of Senior Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.11 to the Registrant's Form S-3 filed August 9, 2006).
4.4	Form of Subordinated Indenture of Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 4.12 to the Registrant's Form S-3 filed August 9, 2006).
4.5	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K filed October 25, 2006).
4.6	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed March 31, 2008).
4.7	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed May 12, 2011).
4.8	Tenth Supplemental Indenture, dated as of January 17, 2012, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 17, 2012).
4.9	Eleventh Supplemental Indenture dated as of January 22, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 23, 2013).

Exhibit Number	Description
4.10	Twelfth Supplemental Indenture dated as of January 24, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed June 26, 2013).
4.11	Thirteenth Supplemental Indenture dated as of September 19, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed September 19, 2013).
4.12	Fourteenth Supplemental Indenture dated as of March 12, 2015 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed on March 12, 2015).
4.13	Fifteenth Supplemental Indenture dated as of June 23, 2015 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.3 to the Registrant's Form 8-K filed June 23, 2015).
4.14	Sixteenth Supplemental Indenture, dated as of January 17, 2017 between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Form 8-K filed January 17, 2017).
4.15	Seventeenth Supplemental Indenture, dated as of December 1, 2017 between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 10.8 to the Registrant's Form 8-K filed December 6, 2017).
4.16	Second Supplemental Indenture, dated December 1, 2017 among Energy Transfer Partners, L.P., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.5 of Form 8-K filed December 6, 2017).
4.17	Indenture, dated as of May 15, 1994, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., relating to Sunoco, Inc.'s 9.00% Debentures due 2024 (incorporated by reference to Exhibit 4.8 to the Registrant's Form 8-K filed October 5, 2012).
4.18	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of May 15, 1994 (incorporated by reference to Exhibit 4.9 to the Registrant's Form 8-K filed October 5, 2012).
4.19	Sixteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.4 of Form 8-K filed September 25, 2017).
4.20	Fifteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.2 of Form 8-K filed September 25, 2017).
4.21	Third Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed December 15, 2017).
4.22	Eighteenth Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed December 15, 2017).
4.23	Tenth Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp., Sunoco Logistics Partners Operations L.P. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 of Form 8-K filed December 15, 2017).
4.24	Eleventh Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp., Sunoco Logistics Partners Operations L.P. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.4 of Form 8-K filed December 15, 2017).
4.25	Second Supplemental Indenture, dated as of December 1, 2017, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.6 of Form 8-K filed December 6, 2017).
4.26	Indenture, dated as of June 8, 2018, among Energy Transfer Partners, L.P. as issuer, Sunoco Logistics Partners Operations L.P., as guarantor, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed June 8, 2018).
4.27	First Supplemental Indenture dated as of June 8, 2018 by and among Energy Transfer Partners, L.P., as issuer, the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed June 8, 2018).
4.28	Forms of Notes (included in Exhibit 4.36 hereto, incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed June 8, 2018).

Exhibit Number	Description
4.29	Second Supplemental Indenture, dated as of January 15, 2019, by and among Energy Transfer Operating, L.P., as issuer, the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed January 15, 2019).
4.30	Third Supplemental Indenture, dated as of March 25, 2019, by and among Energy Transfer Operating, L.P., as issuer, the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed March 27, 2019).
4.31*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Listed Senior Notes.
4.32*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Series C Preferred Units.
4.33*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Series D Preferred Units.
4.34*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Series E Preferred Units.
10.1+	Energy Transfer Partners Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2010).
10.2+	Form of Grant Agreement under the Energy Transfer Partners, L.P. Amended and Restated 2004 Unit Plan and the 2008 Energy Transfer Partners, L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 1, 2004).
10.3+	Energy Transfer Partners, L.L.C. Annual Bonus Plan effective January 1, 2014 (incorporated by reference to Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended June 30, 2014).
10.3.1+	Amended and Restated Energy Transfer Partners, L.L.C. Annual Bonus Plan (incorporated by reference to Exhibit 10.3 of Form 10-Q filed August 9, 2018).
10.4	Guarantee of Collection, dated as of April 30, 2013, by and between Regency Energy Partners LP, PEPL Holdings, LLC and Regency Energy Finance Corp. (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed on April 30. 2013).
10.5	Exchange and Redemption Agreement by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and ETE Common Holdings, LLC dated August 7, 2013 (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed on August 8, 2013).
10.6	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed February 1, 2005).
10.7	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed September 18, 2006).
10.8	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.56 to the Registrant's Form 10-Q for the quarter ended May 31, 2007).
10.8.1	Note Purchase Agreement, dated December 9, 2009, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 14, 2009).
10.9	Credit Agreement dated as of December 1, 2017 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, the other lenders party thereto and the other parties named therein (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed December 6, 2017).
10.10	Amendment No. 1 to Five-Year Credit Agreement, Joinder and Increase and Extension Agreement, dated as of October 19, 2018, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P., and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed October 19, 2018).
10.11	364-Day Credit Agreement dated December 1, 2017 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, the other lenders party thereto and other parties thereto (incorporated by referenced to Exhibit 10.2 to the Registrant's Form 8-K filed December 6, 2017).
10.11.1	Amendment No. 1 to 364-Day Credit Agreement, Joinder and Increase and Extension Agreement, dated as of October 19, 2018, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P., and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed October 19, 2018).

Exhibit Number	Description
10.11.2	Amendment No. 2 to 364-Day Credit Agreement and Extension Agreement dated as of November 19, 2019 among Energy Transfer Operating, L.P., Sunoco Logistics Partners Operations L.P., Wells Fargo Bank, National Association, as Administrative Agent, the other lenders party thereto and the other parties named therein (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on November 21, 2019).
10.12	Guaranty dated as of December 1, 2017 by Sunoco Logistics Partners Operations, L.P. and each other Subsidiary from time to time party thereto in favor of Wells Fargo Bank, National Association, as Administrative Agent for the Lenders under that certain Credit Agreement dated as of December 1, 2017 (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K No. 1-31219, filed December 6, 2017).
10.13	Guaranty dated as of December 1, 2017 by Sunoco Logistics Partners Operations, L.P. and each other Subsidiary from time to time party thereto in favor of Wells Fargo Bank, National Association, as Administrative Agent for the Lenders under that certain 364-Day Credit Agreement dated as of December 1, 2017 (incorporated by reference to Exhibit 10.4 to the Registrant's Form 8-K filed December 6, 2017).
10.14	Guarantee of Collection made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on March 28, 2012).
10.15	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P., and Citrus ETP Finance LLC (incorporated by reference to Exhibit 10.2 to Registrant's Form 8-K filed on March 28, 2012).
10.16	Contingent Residual Support Agreement by and among Energy Transfer Partners, L.P., AmeriGas Finance LLC, AmeriGas Finance Corp., AmeriGas Partners, L.P. and, for certain limited purposes, UGI Corporation, dated January 12, 2012 (incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on January 13, 2012).
10.17	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 to Registrant's Form 8-K filed on May 1, 2012).
10.18	Guarantee of Collection, made as of April 1, 2015, by ETP Retail Holdings, LLC to Sunoco LP and Sunoco Finance Corp. (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed on April 1, 2015).
10.19	Support Agreement, made as of April 1, 2015, by and among Sunoco, Inc. (R&M), Sunoco LP, Sunoco Finance Corp. and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 1, 2015).
10.20	Support Agreement, made as of April 1, 2015, by and among Atlantic Refining & Marketing Corp., Sunoco LP, Sunoco Finance Corp. and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.4 to the Registrant's Form 8-K filed April 1, 2015).
10.21	Sixth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, as guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 30, 2015).
10.22	Eighth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.4 to the Registrant's Form 8-K filed April 30, 2015).
10.23+	Separation and Non-Solicit Agreement and Full Release of Claims (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed May 14, 2015).
10.24	Seventh Supplemental Indenture, dated as of May 28, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, Energy Transfer Partners, L.P., as co-obligor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed June 1, 2015).
10.25	Eighth Supplemental Indenture, dated as of August 10, 2015, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed August 13, 2015).
10.26	Ninth Supplemental Indenture, dated as of December 1, 2017 by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.9 to the Registrant's Form 8-K filed December 6, 2017).
10.27	Ninth Supplemental Indenture, dated as of August 10, 2015, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed August 13, 2015).
10.28	Tenth Supplemental Indenture, dated as of December 1, 2017 by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.10 to the Registrant's Form 8-K filed December 6, 2017).

Exhibit Number	Description
10.29	Contribution Agreement, dated as of July 14, 2015, by and among Susser Holdings Corporation, Heritage Holdings, Inc., ETP Holdco Corporation, Sunoco LP, Sunoco GP LLC and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed July 15, 2015).
10.30	Exchange and Repurchase Agreement, dated as of July 14, 2015, by and among Energy Transfer Equity, L.P., Energy Transfer Partners GP, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed July 15, 2015).
10.31	Contribution Agreement dated as of November 15, 2015, by and among Sunoco, LLC, Sunoco, Inc., ETP Retail Holdings, LLC, Sunoco LP, Sunoco GP LLC, and solely with respect to Section 11.19 and other provisions related thereto, Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed November 19, 2015).
10.32	Energy Transfer Partners Deferred Compensation Plan for Former Sunoco Executives effective October 5, 2012 (incorporated by reference to Exhibit 10.21 of the Form 10-K of Sunoco Logistics Partners L.P. filed February 25, 2016).
10.33	Guarantee of Collection, dated as of March 31, 2016, by and between ETP Retail Holdings, LLC and Sunoco LP (incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed April 1, 2016).
10.34	Support Agreement, dated as of March 31, 2016, by and between Sunoco, Inc., Sunoco LP, and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.2 to the Registrant's Form 8-K filed April 1, 2016).
10.35	Support Agreement, dated as of March 31, 2016, by and between Atlantic Refining & Marketing Corp., Sunoco LP, and ETP Retail Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Registrant's Form 8-K filed April 1, 2016).
10.36	Form of Commercial Paper Dealer Agreement between Energy Transfer Partners, L.P., as Issuer, and the Dealer party thereto (incorporated by reference to Exhibit 99.1 to the Registrant's Form 8-K filed August 22, 2016).
10.37	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).
10.38	Transition Services Agreement, dated as of April 2, 2018, by and among USA Compression Partners, LP, CDM Resource Management LLC, CDM Environmental & Technical Services LLC and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed April 3, 2018).
10.39	Term Loan Credit Agreement dated as of October 17, 2019 among Energy Transfer Operating, L.P., Toronto Dominion (Texas) LLC, as Administrative Agent, the other lenders party thereto and the other parties named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 18, 2019).
10.40	Guaranty dated as of October 17, 2019 between Sunoco Logistics Partners Operations L.P. and Toronto Dominion (Texas) LLC, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed October 18, 2019).
21.1*	List of Subsidiaries.
23.1*	Consent of Grant Thornton LLP.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of December 31, 2019 and December 31, 2018; (ii) our Consolidated Statements of Operations for the years ended December 31, 2019, 2018 and 2017; (iii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2019, 2018 and 2017; (iv) our Consolidated Statement of Partners' Capital for the years ended December 31, 2019, 2018 and 2017; (v) our Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; and (vi) the notes to our Consolidated Financial Statements.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

*	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 OPERATING, L.P.

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

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

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

Dated: February 21, 2020

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 of Directors (Principal Executive Officer)	February 21, 2020
/s/ Thomas E. Long Thomas E. Long	Chief Financial Officer (Principal Financial Officer)	February 21, 2020
/s/ A. Troy Sturrock A. Troy Sturrock	Senior Vice President and Controller (Principal Accounting Officer)	February 21, 2020
/s/ Matthew S. Ramsey Matthew S. Ramsey	President, Chief Operating Officer and Director	February 21, 2020
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	Chief Commercial Officer and Director	February 21, 2020
/s/ David K. Skidmore David K. Skidmore	Director	February 21, 2020
/s/ W. Brett Smith W. Brett Smith	Director	February 21, 2020
/s/ William P. Williams William P. Williams	Director	February 21, 2020

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of Energy Transfer Partners, L.L.C. and
Unitholders of Energy Transfer Operating, L.P.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Energy Transfer Operating, L.P. (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

Change in accounting principle
As discussed in Note 2 to the consolidated financial statements, the Partnership has changed its method of accounting for leases due to the adoption of the new leasing standard. The Partnership adopted the new leasing standard by recognizing a cumulative catch-up adjustment to the opening balance sheet as of January 1, 2019.

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 Public Company Accounting Board (United States) ("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. The Partnership is not required to have an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

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.

Critical audit matters
The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Goodwill Impairment Assessment (Note 2)
Of the $4.9 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2019, approximately $380.0 million is recorded in a reporting unit for which the estimated fair value exceeded the carrying value by less than 20% in the most recent quantitative test. The Partnership engaged third party valuation specialists for the estimation of the fair value of this reporting unit. We identified the estimation of the fair value of the reporting unit as a critical audit matter.

The principal considerations for our determination that the estimation of the fair value of the reporting unit was a critical audit matter are that the extent to which the fair value of the reporting unit exceeds its carrying value is relatively low, the estimate of the future cash flows, including projected growth rates, forecasted costs, discount rates and future market conditions requires a high degree of judgement, and the application of valuation methodologies can be complex.

Our audit procedures related to the estimation of the fair value of the reporting unit included the following procedures, among others. We tested the effectiveness of controls relating to management's review of the assumptions used to develop the future cash flows, the reconciliation of cash flows prepared by management to the data used in the third party valuation reports, the discount rates used, and valuation methodologies applied. In addition to testing the effectiveness of controls, we also performed the following:

- Compared the actual current results of the relevant reporting unit to the expected performance of that reporting unit based on prior period financial forecasts, as applicable.
- Utilized an internal valuation specialist to evaluate:
    - The methodologies used and whether they were acceptable for the underlying assets or operations and being applied correctly by performing independent calculations,
    - The appropriateness of the discount rates by recalculating the weighted average costs of capital, and
    - The qualifications of the third party valuation specialists engaged by the Partnership based on their credentials and experience.
- Tested the reasonableness of the projected growth rate and forecasted costs by comparing such items to historical operating results of the relevant reporting unit and by assessing the likelihood or capability of the reporting unit to undertake activities or initiatives underpinning significant drivers of growth in the forecasted period.

Environmental Remediation (Note 10)
The Partnership's operations are subject to extensive federal, tribal, state and local environmental and safety laws and regulations that require expenditures for remediation at current and former facilities. We identified the identification, assessment and estimation of the environmental exposure associated with certain sites of ETC Sunoco Holdings LLC as a critical audit matter.

The principal considerations for our determination that the identification, assessment and estimation of the environmental exposure was a critical audit matter are that there was a high estimation uncertainty due to the complexity of the actuarial methods utilized, the discount rate applied and the potential for changes in the timing and extent of remediation. This required an increased extent of effort when performing audit procedures, related to identification, assessment and estimation of the environmental exposure, including the need to involve actuarial specialists.

Our audit procedures related to the identification, assessment and estimation of the Partnership's environmental exposure included the following procedures, among others. We tested the effectiveness of controls relating to the identification and review of the historical claims, payments and reserve data provided to the third party actuary specialist and the reconciliation of that data to that used in the actuary report, and the review of the discount rate and actuarial methods applied. In addition to testing the effectiveness of controls, we performed the following procedures:

- Utilized an external actuarial specialist to evaluate:
    - The methodologies used and whether they were acceptable for the underlying operations,
    - The qualifications of the third party actuary specialist engaged by the Partnership based on their credentials and experience.
- Evaluated the appropriateness of the discount rate used by comparing it to the historical rate of return from the captive insurance company's investment portfolio used to fund the underlying liabilities, and
- Evaluated the life-to-date payments, reserves, and payment patterns by agreeing the historical claims and payment amounts to the underlying claims or general ledger.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2004.

Dallas, Texas
February 21, 2020

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

	December 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 253	$ 418
Accounts receivable, net	4,439	4,009
Accounts receivable from related companies	175	176
Inventories	1,847	1,677
Income taxes receivable	141	73
Derivative assets	23	111
Other current assets	282	356
Total current assets	7,160	6,820
Property, plant and equipment	85,359	79,280
Accumulated depreciation and depletion	(15,388)	(12,625)
	69,971	66,655
Advances to and investments in unconsolidated affiliates	3,018	2,636
Lease right-of-use assets, net	877	—
Other non-current assets, net	976	1,006
Long-term affiliate receivable	5,926	440
Intangible assets, net	5,695	6,000
Goodwill	4,902	4,885
Total assets	$ 98,525	$ 88,442

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

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

	December 31, 2019	December 31, 2018
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,625	$ 3,491
Accounts payable to related companies	27	119
Derivative liabilities	147	185
Operating lease current liabilities	54	—
Accrued and other current liabilities	3,216	2,847
Current maturities of long-term debt	12	2,655
Total current liabilities	7,081	9,297
Long-term debt, less current maturities	50,334	37,853
Non-current derivative liabilities	273	104
Non-current operating lease liabilities	816	—
Deferred income taxes	3,113	2,884
Other non-current liabilities	1,109	1,184
Commitments and contingencies		
Redeemable noncontrolling interests	492	499
Equity:		
Limited Partners:		
Series A Preferred Unitholders (950,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	958	958
Series B Preferred Unitholders (550,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	556	556
Series C Preferred Unitholders (18,000,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	440	440
Series D Preferred Unitholders (17,800,000 units authorized, issued and outstanding as of December 31, 2019 and 2018, respectively)	434	434
Series E Preferred Unitholders (32,000,000 units authorized, issued and outstanding as of December 31, 2019)	786	—
Common Unitholders and Other	24,133	26,372
Accumulated other comprehensive loss	(18)	(42)
Total partners' capital	27,289	28,718
Noncontrolling interests	8,018	7,903
Total equity	35,307	36,621
Total liabilities and equity	$ 98,525	$ 88,442

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

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

	Years Ended December 31,		
	2019	2018	2017
REVENUES:			
Refined product sales	$ 16,634	$ 17,458	$ 11,166
Crude sales	15,917	14,425	10,706
NGL sales	8,290	9,986	7,781
Gathering, transportation and other fees	9,042	6,797	4,435
Natural gas sales	3,295	4,452	4,172
Other	854	969	2,263
Total revenues	54,032	54,087	40,523
COSTS AND EXPENSES:			
Cost of products sold	39,603	41,658	30,966
Operating expenses	3,267	3,089	2,644
Depreciation, depletion and amortization	3,124	2,843	2,541
Selling, general and administrative	679	664	568
Impairment losses	74	431	1,039
Total costs and expenses	46,747	48,685	37,758
OPERATING INCOME	7,285	5,402	2,765
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(2,257)	(1,709)	(1,575)
Equity in earnings of unconsolidated affiliates	298	344	144
Impairment of investments in unconsolidated affiliates	—	—	(313)
Losses on extinguishments of debt	(2)	(109)	(42)
Gains (losses) on interest rate derivatives	(241)	47	(37)
Other, net	303	69	206
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	5,386	4,044	1,148
Income tax expense (benefit) from continuing operations	200	5	(1,804)
INCOME FROM CONTINUING OPERATIONS	5,186	4,039	2,952
Loss from discontinued operations, net of income taxes	—	(265)	(177)
NET INCOME	5,186	3,774	2,775
Less: Net income attributable to noncontrolling interests	1,051	715	420
Less: Net income attributable to redeemable noncontrolling interests	51	39	—
Less: Net income (loss) attributable to predecessor	—	(5)	274
NET INCOME ATTRIBUTABLE TO PARTNERS	$ 4,084	$ 3,025	$ 2,081

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

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

	Years Ended December 31,		
	2019	2018	2017
Net income	$ 5,186	$ 3,774	$ 2,775
Other comprehensive income (loss), net of tax:			
Change in value of available-for-sale securities	11	(4)	6
Actuarial gain (loss) relating to pension and other postretirement benefits	23	(43)	(12)
Change in other comprehensive income from unconsolidated affiliates	(10)	4	1
	24	(43)	(5)
Comprehensive income	5,210	3,731	2,770
Less: Comprehensive income attributable to noncontrolling interests	1,051	715	420
Less: Comprehensive income attributable to redeemable noncontrolling interests	51	39	—
Less: Comprehensive income (loss) attributable to predecessor	—	(5)	274
Comprehensive income attributable to partners	$ 4,108	$ 2,982	$ 2,076

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

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

	Limited Partners						
	Preferred Unitholders	Common Unitholders and Other	General Partner	AOCI	Non-controlling Interest	Predecessor Equity	Total
Balance, December 31, 2016	$ —	$ 18,407	$ 206	$ 8	$ 7,820	$ 2,497	$ 28,938
Distributions to partners	—	(2,516)	(952)	—	—	—	(3,468)
Distributions to noncontrolling interests	—	—	—	—	(430)	(284)	(714)
Partnership units issued for cash	1,479	2,283	—	—	—	—	3,762
Subsidiary units issued for cash	—	—	—	—	—	333	333
Sunoco Logistics Merger	—	5,938	—	—	(5,938)	—	—
Capital contributions from noncontrolling interests	—	—	—	—	2,202	—	2,202
Sale of Bakken pipeline interest	—	1,260	—	—	740	—	2,000
Sale of Rover pipeline interest	—	93	—	—	1,385	—	1,478
Acquisition of PennTex noncontrolling interest	—	(48)	—	—	(232)	—	(280)
Other comprehensive loss, net of tax	—	—	—	(5)	—	—	(5)
Other, net	—	35	—	—	(85)	(4)	(54)
Net income	12	1,079	990	—	420	274	2,775
Balance, December 31, 2017	1,491	26,531	244	3	5,882	2,816	36,967
Distributions to partners	(100)	(3,376)	(1,080)	—	—	—	(4,556)
Distributions to noncontrolling interests	—	—	—	—	(891)	(276)	(1,167)
Partnership units issued for cash	867	58	—	—	—	—	925
Subsidiary units repurchased	—	—	—	—	—	(300)	(300)
Energy Transfer Merger	—	1,370	(340)	—	1,474	(2,504)	—
Capital contributions from noncontrolling interests	—	—	—	—	649	—	649
Cumulative effect adjustment due to change in accounting principle	—	—	—	—	—	(54)	(54)
Deemed distribution, net	—	37	—	—	58	(497)	(402)
Acquisition of USAC	—	—	—	—	—	832	832
Other comprehensive loss, net of tax	—	—	—	(43)	—	—	(43)
Other, net	(3)	53	(17)	(2)	16	(12)	35
Net income (loss), excluding amounts attributable to redeemable noncontrolling interests	133	1,699	1,193	—	715	(5)	3,735
Balance, December 31, 2018	2,388	26,372	—	(42)	7,903	—	36,621
Distributions to partners	(197)	(6,087)	—	—	—	—	(6,284)
Distributions to noncontrolling interests	—	—	—	—	(1,399)	—	(1,399)
Partnership units issued for cash	780	—	—	—	—	—	780
Capital contributions from noncontrolling interests	—	—	—	—	348	—	348
Sale of noncontrolling interest in subsidiary	—	—	—	—	93	—	93
Other comprehensive loss, net of tax	—	—	—	24	—	—	24
Other, net	(1)	(32)	—	—	22	—	(11)
Net income, excluding amounts attributable to redeemable noncontrolling interests	204	3,880	—	—	1,051	—	5,135
Balance, December 31, 2019	$ 3,174	$ 24,133	$ —	$ (18)	$ 8,018	$ —	$ 35,307

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

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

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES:			
Net income	$ 5,186	$ 3,774	$ 2,775
Reconciliation of net income to net cash provided by operating activities:			
Loss from discontinued operations	—	265	177
Depreciation, depletion and amortization	3,124	2,843	2,541
Deferred income taxes	221	(8)	(1,841)
Inventory valuation adjustments	(79)	85	(24)
Non-cash compensation expense	111	105	99
Impairment losses	74	431	1,039
Impairment of investments in unconsolidated affiliates	—	—	313
Losses on extinguishment of debt	2	109	42
Distributions on unvested awards	(9)	(33)	(35)
Equity in earnings of unconsolidated affiliates	(298)	(344)	(144)
Distributions from unconsolidated affiliates	285	328	297
Other non-cash	113	(113)	(249)
Net change in operating assets and liabilities, net of effects of acquisitions	(479)	117	(173)
Net cash provided by operating activities	8,251	7,559	4,817
INVESTING ACTIVITIES:			
Cash proceeds from sale of noncontrolling interest in subsidiary	93	—	—
Cash proceeds from USAC acquisition, net of cash received	—	711	—
Cash proceeds from Bakken pipeline transaction	—	—	2,000
Cash proceeds from Rover pipeline transaction	—	—	1,478
Cash paid for acquisition of PennTex noncontrolling interest	—	—	(280)
Cash paid for all other acquisitions	(7)	(429)	(303)
Capital expenditures, excluding allowance for equity funds used during construction	(5,936)	(7,407)	(8,444)
Contributions in aid of construction costs	80	109	24
Contributions to unconsolidated affiliates	(523)	(26)	(268)
Distributions from unconsolidated affiliates in excess of cumulative earnings	98	69	135
Proceeds from the sale of assets	54	87	45
Other	18	(16)	1
Net cash used in investing activities	(6,123)	(6,902)	(5,612)

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

FINANCING ACTIVITIES:			
Proceeds from borrowings	22,583	28,538	29,389
Repayments of debt	(16,874)	(27,297)	(29,387)
Repayments of notes payable to related party	(1,328)	(440)	(423)
Common units issued for cash	—	58	2,283
Preferred units issued for cash	780	867	1,479
Redeemable noncontrolling interests issued for cash	—	465	—
Predecessor units issued for cash	—	—	333
Capital contributions from noncontrolling interests	348	649	1,214
Distributions to partners	(6,284)	(4,556)	(3,468)
Predecessor distributions to partners	—	(276)	(284)
Distributions to noncontrolling interests	(1,399)	(891)	(430)
Distributions to redeemable noncontrolling interests	—	(24)	—
Repurchases of common units	—	(24)	—
Subsidiary repurchases of common units	—	(300)	—
Redemption of Legacy ETP Preferred Units	—	—	(53)
Debt issuance costs	(117)	(162)	(83)
Other	(2)	85	2
Net cash provided by (used in) financing activities	(2,293)	(3,308)	572
DISCONTINUED OPERATIONS:			
Operating activities	—	(484)	136
Investing activities	—	3,207	(38)
Changes in cash included in current assets held for sale	—	11	(5)
Net increase in cash and cash equivalents of discontinued operations	—	2,734	93
Increase (decrease) in cash and cash equivalents	(165)	83	(130)
Cash and cash equivalents, beginning of period	418	335	465
Cash and cash equivalents, end of period	$ 253	$ 418	$ 335

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

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

1. OPERATIONS AND BASIS OF PRESENTATION:

The consolidated financial statements presented herein contain the results of Energy Transfer Operating, L.P. and its subsidiaries (the "Partnership," "we," "us," "our" or "ETO").

ETO is a consolidated subsidiary of Energy Transfer LP. 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, the former common 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.

The Energy Transfer Merger was a combination of entities under common control; therefore, Sunoco LP, Lake Charles LNG and USAC's (see Note 3 for more information) assets and liabilities were not adjusted. The Partnership's consolidated financial statements have been retrospectively adjusted to reflect consolidation beginning January 1, 2017 of Sunoco LP and Lake Charles LNG and April 2, 2018 of USAC (the date ET acquired USAC, see Note 3). Predecessor equity included on the consolidated financial statements represents Sunoco LP, Lake Charles LNG and USAC's equity prior to the Energy Transfer Merger.

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." For purposes of maintaining clarity, the following references are used herein:

- References to "Sunoco Logistics" refer to the entity named Sunoco Logistics Partners L.P. and its subsidiaries prior to the close of the Sunoco Logistics Merger; and
- References to "ETO" for periods prior to the Sunoco Logistics Merger refer to the consolidated entity named Energy Transfer Partners, L.P. and its subsidiaries prior to the close of the Sunoco Logistics Merger.

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

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

The historical common units amount presented in these consolidated financial statements have been retrospectively adjusted to reflect the 1.5 to one unit-for-unit exchange in connection with the Sunoco Logistics Merger.

The Partnership is engaged in the gathering and processing, compression, treating and transportation of natural gas, focusing on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring and Avalon shales.

The Partnership 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, 2019, 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, 2019, our interest in USAC consisted of 100% of the general partner and 46.1 million common units.

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

The consolidated financial statements of the Partnership presented herein include the results of operations of our controlled subsidiaries, including Sunoco LP and USAC.

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.

Lease Accounting

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, *Leases (Topic 842)*, which has amended the FASB Accounting Standards Codification ("ASC") and introduced Topic 842, Leases. On January 1, 2019, the Partnership has adopted ASC Topic 842 ("Topic 842"), which is effective for interim and annual reporting periods beginning on or after December 15, 2018. Topic 842 requires entities to recognize lease assets and liabilities on the balance sheet for all leases with a term of more than one year, including operating leases, which historically were not recorded on the balance sheet in accordance with the prior standard.

To adopt Topic 842, the Partnership recognized a cumulative catch-up adjustment to the opening balance sheet as of January 1, 2019 related to certain leases that existed as of that date. As permitted, we have not retrospectively modified our consolidated financial statements for comparative purposes. The adoption of the standard had a material impact on our consolidated balance sheet, but did not have an impact on our consolidated statements of operations, comprehensive income or cash flows. As a result of adoption, we have recorded additional net right-of-use ("ROU") lease assets and lease liabilities of approximately $888 million and $888 million, respectively, as of January 1, 2019. In addition, we have updated our business processes, systems, and internal controls to support the on-going reporting requirements under the new standard.

To adopt Topic 842, the Partnership elected the package of practical expedients permitted under the transition guidance within the standard. The expedient package allowed us not to reassess whether existing contracts contained a lease, the lease classification of existing leases and initial direct cost for existing leases. In addition to the package of practical expedients, the Partnership has elected not to capitalize amounts pertaining to leases with terms less than twelve months, to use the portfolio approach to determine discount rates, not to separate non-lease components from lease components and not to apply the use of hindsight to the active lease population.

Cumulative-effect adjustments made to the opening balance sheet at January 1, 2019 were as follows:

	Balance at December 31, 2018, as previously reported	Adjustments due to Topic 842 (Leases)	Balance at January 1, 2019
Assets:			
Property, plant and equipment, net	$ 66,655	$ (1)	$ 66,654
Lease right-of-use assets, net	—	889	889
Liabilities:			
Operating lease current liabilities	$ —	$ 71	$ 71
Accrued and other current liabilities	2,847	(1)	2,846
Current maturities of long-term debt	2,655	1	2,656
Long-term debt, less current maturities	37,853	6	37,859
Non-current operating lease liabilities	—	823	823
Other non-current liabilities	1,184	(12)	1,172

Additional disclosures related to lease accounting 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 the 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) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31,		
	2019	2018	2017
Accounts receivable	$ (423)	$ 506	$ (951)
Accounts receivable from related companies	(25)	128	(462)
Inventories	(98)	282	58
Other current assets	100	7	40
Other non-current assets, net	(126)	(109)	(88)
Accounts payable	101	(769)	713
Accounts payable to related companies	(94)	(206)	486
Accrued and other current liabilities	50	365	(56)
Other non-current liabilities	(183)	(34)	78
Price risk management assets and liabilities, net	219	(53)	9
Net change in operating assets and liabilities, net of effects of acquisitions	$ (479)	$ 117	$ (173)

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

	Years Ended December 31,		
	2019	2018	2017
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 1,265	$ 1,030	$ 1,060
Lease assets obtained in exchange for new lease liabilities	67	—	—
Net gains (losses) from subsidiary common unit transactions	—	(127)	5
NON-CASH FINANCING ACTIVITIES:			
Contribution of assets from noncontrolling interests	$ —	$ —	$ 988
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 1,798	$ 1,537	$ 1,516
Cash paid for income taxes	30	508	50

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 consider many factors including historical customer collection experience, general and specific economic trends, and known specific issues related to individual customers, sectors, and transactions that might impact collectability. 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.

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,	
	2019	2018
Natural gas, NGLs and refined products [1]	$ 833	$ 833
Crude oil	566	506
Spare parts and other	448	338
Total inventories	$ 1,847	$ 1,677

[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,	
	2019	2018
Deposits paid to vendors	$ 95	$ 141
Prepaid expenses and other	187	215
Total other current assets	$ 282	$ 356

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 2019, USAC recognized a $6 million fixed asset impairment related to certain idle compressor assets. Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York.

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.

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,	
	2019	2018
Land and improvements	$ 1,075	$ 1,168
Buildings and improvements (1 to 45 years)	2,581	2,636
Pipelines and equipment (5 to 83 years)	62,508	58,783
Product storage and related facilities and equipment (2 to 83 years)	4,739	4,978
Right of way (20 to 83 years)	4,736	4,533
Other (1 to 48 years)	1,499	1,115
Construction work-in-process	8,221	6,067
Property, plant and equipment, gross	85,359	79,280
Less: Accumulated depreciation and depletion	(15,388)	(12,625)
Property, plant and equipment, net	$ 69,971	$ 66,655

We recognized the following amounts for the periods presented:

	Years Ended December 31,		
	2019	2018	2017
Depreciation, depletion and amortization expense	$ 2,816	$ 2,522	$ 2,199
Capitalized interest	166	294	286

Advances to and Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies. 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,	
	2019	2018
Regulatory assets	$ 42	$ 43
Pension assets	84	68
Deferred charges	178	178
Restricted funds	178	178
Other	494	539
Total other non-current assets, net	$ 976	$ 1,006

Restricted funds includes an immaterial amount of restricted cash primarily 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, 2019		December 31, 2018	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 7,074	$ (1,741)	$ 7,106	$ (1,493)
Patents (10 years)	48	(35)	48	(30)
Trade Names (20 years)	66	(31)	66	(28)
Other (5 to 20 years)	19	(12)	33	(9)
Total amortizable intangible assets	7,207	(1,819)	7,253	(1,560)
Non-amortizable intangible assets:				
Trademarks	295	—	295	—
Other	12	—	12	—
Total non-amortizable intangible assets	307	—	307	—
Total intangible assets	$ 7,514	$ (1,819)	$ 7,560	$ (1,560)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2019	2018	2017
Reported in depreciation, depletion and amortization expense	$ 308	$ 321	$ 336

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

Years Ending December 31:		
2020	$	371
2021		367
2022		337
2023		297
2024		284

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 assets were originally recorded.

Sunoco LP performed impairment tests on its indefinite-lived intangible assets during the fourth quarter of 2017 and recognized a total of $17 million in impairment charges on their contractual rights and liquor licenses primarily due to decreases in projected future revenues and cash flows from the date the intangible assets were 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, 2017	$ 10	$ 196	$ 870	$ 693	$ 1,167	$ 1,430	$ —	$ 363	$ 4,729
Acquired	—	—	—	—	—	129	366	—	495
CDM Contribution	—	—	—	—	—	—	253	(253)	—
Impaired	—	—	(378)	—	—	—	—	—	(378)
Other	—	—	—	—	—	—	—	39	39
Balance, December 31, 2018	10	196	492	693	1,167	1,559	619	149	4,885
Acquired	—	42	—	—	—	—	—	—	42
Impaired	—	(12)	(9)	—	—	—	—	—	(21)
Other	—	—	—	—	—	(4)	—	—	(4)
Balance, December 31, 2019	$ 10	$ 226	$ 483	$ 693	$ 1,167	$ 1,555	$ 619	$ 149	$ 4,902

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized.

During the third quarter of 2019, the Partnership recognized a goodwill impairment of $12 million related to the Southwest Gas operations within the interstate segment primarily due to decreases in projected future revenues and cash flows. During the fourth quarter of 2019, the Partnership recognized a goodwill impairment of $9 million related to our North Central operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows.

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.

In connection with aforementioned impairments, 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.

Management does not believe that any of the goodwill balances in its reporting units is currently at significant risk of impairment; however, of the $4.90 billion of goodwill on the Partnership's consolidated balance sheet as of December 31, 2019, approximately $380 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.

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 ARO 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 AROs as of December 31, 2019 and 2018, 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. ETC Sunoco 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, ETC Sunoco is legally or contractually required to abandon in place or remove the asset. We believe we may have additional AROs related to ETC Sunoco'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, 2019 and 2018, other non-current liabilities in the Partnership's consolidated balance sheets included AROs of $223 million and $193 million, respectively. For the years ended December 31, 2019, 2018 and 2017 aggregate accretion expense related to AROs was $5 million, $13 million and $9 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.

Oher non-current assets on the Partnership's consolidated balance sheet included $31 million and $26 million of legally restricted funds for the purpose of settling AROs as of December 31, 2019 and 2018, respectively.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2019	2018
Interest payable	$ 576	$ 503
Customer advances and deposits	123	128
Accrued capital expenditures	1,265	1,030
Accrued wages and benefits	217	283
Taxes payable other than income taxes	263	256
Exchanges payable	67	112
Other	705	535
Total accrued and other current liabilities	$ 3,216	$ 2,847

Deposits or advances are received from our 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 6 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 debt obligations as of December 31, 2019 was $54.08 billion and$50.35 billion , respectively. As of December 31, 2018, the aggregate fair value and carrying amount of our debt obligations was $39.54 billion and $40.51 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, 2019, 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, 2019 and 2018 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at December 31, 2019	
		Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 17	$ 17	$ —
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	65	65	—
Forward Physical Contracts	3	—	3
Power:			
Forwards	11	—	11
Futures	4	4	—
Options – Puts	1	1	—
Options – Calls	1	1	—
NGLs – Forwards/Swaps	260	260	—
Refined Products – Futures	8	8	—
Crude – Forwards/Swaps	13	13	—
Total commodity derivatives	384	369	15
Other non-current assets	31	20	11
Total assets	$ 415	$ 389	$ 26
Liabilities:			
Interest rate derivatives	$ (399)	$ —	$ (399)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(49)	(49)	—
Swing Swaps IFERC	(1)	—	(1)
Fixed Swaps/Futures	(43)	(43)	—
Power:			
Forwards	(5)	—	(5)
Futures	(3)	(3)	—
NGLs – Forwards/Swaps	(278)	(278)	—
Refined Products – Futures	(10)	(10)	—
Total commodity derivatives	(389)	(383)	(6)
Total liabilities	$ (788)	$ (383)	$ (405)

	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:			
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)

Contributions in Aid of Construction Costs

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

Shipping and Handling Costs

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

Costs and Expenses

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. For the years ended December 31, 2019, 2018 and 2017, excise taxes collected by Sunoco LP were $386 million, $370 million and $234 million, 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 interests are adjusted as a change in partners' capital.

Income Taxes

ETO is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to our preferred unitholders as a result of differences between the tax basis and financial basis of assets and liabilities, differences between the tax accounting and financial accounting treatment of certain items, and due to allocation requirements related to taxable income under our Fifth 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, ETO would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2019, 2018 and 2017, 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. 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.

In August 2017, the FASB issued ASU 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. The Partnership adopted the new rules in the first quarter of 2019, and the adoption of the new accounting rules did not have a material impact on the consolidated financial statements and related disclosures.

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 the underlying 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 the underlying 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.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests. The capital account provisions of our Partnership Agreement incorporate principles established for United States Federal income tax purposes and may not be comparable to the partners' capital balances reflected under GAAP in our consolidated financial statements. Subsequent to the Energy Transfer Merger, our general partner owns a non-economic interest in us and, therefore, our net income for partners’ capital and statement of operations presentation purposes is allocated entirely to the Limited Partners.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

2019 and 2020 Transactions

ET Contribution of SemGroup Assets to ETO

On December 5, 2019, ET completed the acquisition of SemGroup. During the first quarter of 2020, ET contributed certain SemGroup assets to ETO through sale and contribution transactions. The Partnership and SemGroup are under common control by ET subsequent to ET’s acquisition of SemGroup; therefore, we will account for these transactions as reorganizations of entities under common control. Accordingly, beginning with the quarter ending March 31, 2020, the Partnership’s consolidated financial statements will be retrospectively adjusted to reflect the consolidation of the contributed SemGroup businesses beginning December 5, 2019 (the date ET acquired SemGroup).

The following table represents the preliminary fair value, as of December 5, 2019, of the SemGroup assets and liabilities transferred from ET to ETO:

	At December 5, 2019
Total current assets	$ 548
Property, plant and equipment	2,544
Other non-current assets	574
Goodwill	230
Intangible assets	280
Total assets	4,176
Total current liabilities	480
Long-term debt, less current maturities	812
Other non-current liabilities	109
Total liabilities	1,401
Noncontrolling interest	335
Partners’ capital	2,440
Total liabilities and partners’ capital	$ 4,176

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 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 IDRs 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 newly authorized and established 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 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 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.

As noted above, ET contributed its interests in USAC to ETO in October 2018. ET's contribution of its interests in USAC was a transaction between entities under common control; therefore, the Partnership's consolidated financial statements reflect USAC on a consolidated basis beginning April 2, 2018, the date that ET obtained control of USAC. The Partnership had previously deconsolidated CDM upon its contribution to USAC on April 2, 2018; however, due to the retrospective consolidation of USAC as of that date, CDM is reflected as a consolidated subsidiary for all periods presented herein.

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 Retail Store Divestment

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, Sunoco LP recorded sales to the sites that were subsequently sold to 7-Eleven of $199 million and $3.2 billion, respectively, which were eliminated in consolidation. Sunoco LP received payments on trade receivables of $3.7 billion and $3.4 billion, respectively, from 7-Eleven for the years ended December 31, 2019 and December 31, 2018 subsequent to the closing of the sale.

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.

There were no results of operations associated with discontinued operations for the year ended December 31, 2019. The results of operations associated with discontinued operations for the years ended December 31, 2018 and 2017 are presented in the following table:

	Years Ended December 31,	
	2018	2017
REVENUES	$ 349	$ 6,964
COSTS AND EXPENSES		
Cost of products sold	305	5,806
Operating expenses	61	763
Depreciation, depletion and amortization	—	34
Selling, general and administrative	7	168
Impairment losses	—	285
Total costs and expenses	373	7,056
OPERATING LOSS	(24)	(92)
OTHER EXPENSE		
Interest expense, net	2	36
Loss on extinguishment of debt	20	—
Other, net	61	1
LOSS FROM DISCONTINUED OPERATIONS BEFORE INCOME TAX EXPENSE	(107)	(129)
Income tax expense	158	48
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	$ (265)	$ (177)

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.

4. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Citrus

We own CrossCountry Energy, LLC, a wholly-owned subsidiary of ETO, 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 5,362-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

We have a 50% interest in FEP which owns an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline in Panola County, Mississippi. Our 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

We own a 50% interest in MEP, which owns approximately 500 miles of natural gas pipeline that extends from Southeast Oklahoma, across Northeast Texas, Northern Louisiana and Central Mississippi to an interconnect with the Transcontinental natural gas pipeline system in Butler, Alabama. Our investment in MEP is reflected in the interstate transportation and storage segment.

The carrying values of the Partnership's advances to and investments in unconsolidated affiliates as of December 31, 2019 and 2018 were as follows:

	December 31,	
	2019	2018
Citrus	$ 1,876	$ 1,737
FEP	218	107
MEP	429	225
Others	495	567
Total	$ 3,018	$ 2,636

The following table presents equity in earnings (losses) of unconsolidated affiliates:

	Years Ended December 31,		
	2019	2018	2017
Citrus	$ 148	$ 141	$ 144
FEP	59	55	53
MEP	15	31	38
Other	76	117	(91)
Total equity in earnings of unconsolidated affiliates	$ 298	$ 344	$ 144

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, Citrus, FEP and MEP (on a 100% basis) for all periods presented, except as noted below:

	December 31,	
	2019	2018
Current assets	$ 247	$ 212
Property, plant and equipment, net	7,680	7,800
Other assets	40	39
Total assets	$ 7,967	$ 8,051
Current liabilities	$ 738	$ 1,534
Non-current liabilities	3,242	3,439
Equity	3,987	3,078
Total liabilities and equity	$ 7,967	$ 8,051

	Years Ended December 31,		
	2019	2018	2017
Revenue	$ 1,192	$ 1,249	$ 1,358
Operating income	683	723	407
Net income	443	460	145

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

5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2019	December 31, 2018
ETO Debt		
9.70% Senior Notes due March 15, 2019	$ —	$ 400
9.00% Senior Notes due April 15, 2019	—	450
5.50% Senior Notes due February 15, 2020 (1)	250	250
5.75% Senior Notes due September 1, 2020 (1)	400	400
4.15% Senior Notes due October 1, 2020 (1)	1,050	1,050
7.50% Senior Notes due October 15, 2020 (1)	1,135	—
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
4.25% Senior Notes due March 15, 2023	995	—
4.20% Senior Notes due September 15, 2023	500	500
4.50% Senior Notes due November 1, 2023	600	600
5.875% Senior Notes due January 15, 2024	1,127	—
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
4.50% Senior Notes due April 15, 2024	750	—
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
5.50% Senior Notes due June 1, 2027	956	—
4.00% Senior Notes due October 1, 2027	750	750
4.95% Senior Notes due June 15, 2028	1,000	1,000
5.25% Senior Notes due April 15, 2029	1,500	—
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	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	1,000
6.25% Senior Notes due April 15, 2049	1,750	—
Floating Rate Junior Subordinated Notes due November 1, 2066	546	546
ETO $2.00 billion Term Loan facility due October 2022	2,000	—
ETO $5.00 billion Revolving Credit Facility due December 2023	4,214	3,694

Unamortized premiums, discounts and fair value adjustments, net	(5)	17
Deferred debt issuance costs	(207)	(178)
	42,120	32,288
Transwestern Debt		
5.36% Senior Notes due December 9, 2020 [(1)]	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		
8.125% Senior Notes due June 1, 2019	—	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	11	14
	246	399
Bakken Project Debt		
3.625% Senior Notes due April 1, 2022	650	—
3.90% Senior Notes due April 1, 2024	1,000	—
4.625% Senior Notes due April 1, 2029	850	—
Bakken $2.50 billion Credit Facility due August 2019	—	2,500
Unamortized premiums, discounts and fair value adjustments, net	(3)	—
Deferred debt issuance costs	(16)	(3)
	2,481	2,497
Sunoco LP Debt		
4.875% Senior Notes Due January 15, 2023	1,000	1,000
5.50% Senior Notes Due February 15, 2026	800	800
6.00% Senior Notes Due April 15, 2027	600	—
5.875% Senior Notes Due March 15, 2028	400	400
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	162	700
Lease-related obligations	135	107
Deferred debt issuance costs	(26)	(23)
	3,071	2,984
USAC Debt		
6.875% Senior Notes due April 1, 2026	725	725
6.875% Senior Notes due September 1, 2027	750	—
USAC $1.60 billion Revolving Credit Facility due April 2023	403	1,050
Deferred debt issuance costs	(26)	(16)
	1,852	1,759
Other	2	7
Total debt	50,346	40,508
Less: Current maturities of long-term debt	12	2,655
Long-term debt, less current maturities	$ 50,334	$ 37,853

(1) As of December 31, 2019, 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 redeemed in January 2020.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $273 million in unamortized net premiums, fair value adjustments and deferred debt issuance costs:

2020	$ 3,021
2021	1,412
2022	5,792
2023	8,960
2024	4,337
Thereafter	27,097
Total	$ 50,619

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.

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.

ETO January 2020 Senior Notes Offering and Redemption

On January 22, 2020, ETO completed a registered offering (the "January 2020 Senior Notes Offering") of $1.00 billion aggregate principal amount of the Partnership's 2.900% Senior Notes due 2025, $1.50 billion aggregate principal amount of the Partnership's 3.750% Senior Notes due 2030 and $2.00 billion aggregate principal amount of the Partnership's 5.000% Senior Notes due 2050, (collectively, the "Notes"). The Notes are fully and unconditionally guaranteed by the Partnership's wholly owned subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis.

Utilizing proceeds from the January 2020 Senior Notes Offering, ETO redeemed its $400 million aggregate principal amount of 5.75% Senior Notes due September 1, 2020, its $1.05 billion aggregate principal amount of 4.15% Senior Notes due October 1, 2020, its $1.14 billion aggregate principal amount of 7.50% Senior Notes due October 15, 2020, its $250 million aggregate principal amount of 5.50% Senior Notes due February 15, 2020, ET's $52 million aggregate principal amount of 7.50% Senior Notes due October 15, 2020 and Transwestern's $175 million aggregate principal amount of 5.36% Senior Notes due December 9, 2020.

ET-ETO Senior Notes Exchange

In February 2019, ETO commenced offers to exchange all of ET's outstanding senior notes for senior notes issued by ETO (the "ET-ETO senior notes exchange"). Approximately 97% of ET's outstanding senior notes were tendered and accepted, and substantially all the exchanges settled on March 25, 2019. In connection with the exchange, ETO issued approximately $4.21 billion aggregate principal amount of the following senior notes:

- $1.14 billion aggregate principal amount of 7.50% senior notes due 2020;
- $995 million aggregate principal amount of 4.25% senior notes due 2023;
- $1.13 billion aggregate principal amount of 5.875% senior notes due 2024; and
- $956 million aggregate principal amount of 5.50% senior notes due 2027.

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.

Panhandle Senior Notes Redemption

In June 2019, Panhandle's $150 million aggregate principal amount of 8.125% senior notes matured and were repaid with borrowings under an affiliate loan agreement with ETO.

Bakken Senior Notes Offering

In March 2019, Midwest Connector Capital Company LLC, a wholly-owned subsidiary of Dakota Access, issued the following senior notes related to the Bakken pipeline:

- $650 million aggregate principal amount of 3.625% senior notes due 2022;
- $1.00 billion aggregate principal amount of 3.90% senior notes due 2024; and
- $850 million aggregate principal amount of 4.625% senior notes due 2029.

The $2.48 billion in net proceeds from the offering were used to repay in full all amounts outstanding on the Bakken credit facility and the facility was terminated.

Sunoco LP Senior Notes Offering

In March 2019, Sunoco LP issued $600 million aggregate principal amount of 6.00% senior notes due 2027 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP's existing borrowings under its credit facility. In July 2019, Sunoco LP completed an exchange of these notes for registered notes with substantially identical terms.

USAC Senior Notes Offering

In March 2019, USAC issued $750 million aggregate principal amount of 6.875% senior notes due 2027 in a private placement, and in December 2019, USAC exchanged those notes for substantially identical senior notes registered under the Securities Act. The net proceeds from this offering were used to repay a portion of USAC's existing borrowings under its credit facility and for general partnership purposes.

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.

Credit Facilities, Term Loan and Commercial Paper

ETO Term Loan

On October 17, 2019, ETO entered into a term loan credit agreement (the "ETO Term Loan") providing for a $2.00 billion three-year term loan credit facility. Borrowings under the term loan agreement mature on October 17, 2022 and are available for working capital purposes and for general partnership purposes. The term loan agreement is unsecured and is guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P.

As of December 31, 2019, the ETO Term Loan had $2.00 billion outstanding and was fully drawn. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.78%.

ETO Five-Year Credit Facility

ETO's revolving credit facility (the "ETO Five-Year Credit Facility") allows for unsecured borrowings up to $5.00 billion and matures on 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, 2019, the ETO Five-Year Credit Facility had $4.21 billion outstanding, of which $1.64 billion was commercial paper. The amount available for future borrowings was $709 million after taking into account letters of credit of $77 million. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 2.88%.

ETO 364-Day Facility

ETO's 364-day revolving credit facility (the "ETO 364-Day Facility") allows for unsecured borrowings up to $1.00 billion and matures on November 27, 2020. As of December 31, 2019, the ETO 364-Day Facility had no outstanding borrowings.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.50 billion revolving credit facility (the "Sunoco LP Credit Facility"). As of December 31, 2019, the Sunoco LP Credit Facility had $162 million outstanding borrowings and $8 million in standby letters of credit. The amount available for future borrowings was $1.33 billion at December 31, 2019. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 3.75%.

USAC Credit Facility

USAC maintains a $1.60 billion revolving credit facility (the "USAC Credit Facility"), which matures on April 2, 2023 and permits up to $400 million of future increases in borrowing capacity. As of December 31, 2019, USAC had $403 million of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2019, USAC had $1.2 billion of availability under its credit facility. The weighted average interest rate on the total amount outstanding as of December 31, 2019 was 4.31%.

Covenants Related to Our Credit Agreements

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 contain 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 1.250% 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 4.04 to 1 at December 31, 2019, 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.

Panhandle's restrictive covenants include restrictions on liens securing debt and guarantees and restrictions on mergers and on the sales of assets. A breach of any of these covenants could result in acceleration of Panhandle's debt.

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) 5.5 to 1 through the end of the fiscal quarter ending December 31, 2019 and (ii) 5.0 to 1.0 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 and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2019.

6. REDEEMABLE NONCONTROLLING INTERESTS

Certain redeemable noncontrolling interests in the Partnership's subsidiaries are reflected as mezzanine equity on the consolidated balance sheet. Redeemable noncontrolling interests as of December 31, 2019 included a balance of $477 million related to the USAC Preferred Units described below and a balance of $15 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

In 2018, USAC issued 500,000 USAC Preferred Units in a private placement 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.

7. EQUITY:

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

Class K Units

As of December 31, 2019, a total of 101.5 million Class K Units were held by wholly-owned subsidiaries of ETO. Each Class K Unit 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 ETP Holdco. If the Partnership 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.

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 previously 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.

Class M Units

On July 1, 2019, ETO issued a new class of limited partner interests titled Class M Units to ETP Holdco, a wholly-owned subsidiary of the Partnership, in exchange for the contribution of ETP Holdco's equity ownership interest in Panhandle to the Partnership.

The Class M Units generally do not have any voting rights. The Class M Units are entitled to aggregate cash distributions equal to 8.00% 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 M Units are owned by a wholly-owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements.

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. In April 2019, ETO issued 32 million of its 7.600% Series E Preferred Units at a price of $25 per unit. As of December 31, 2019 all of our Series A, Series B, Series C, Series D and Series E Preferred Units issued remain outstanding.

The following table summarizes changes in the amounts of our Series A, Series B, Series C, Series D and Series E preferred units for the years ended December 31, 2019, 2018 and 2017 were as follows:

	Preferred Unitholders					
	Series A	Series B	Series C	Series D	Series E	Total
Balance, December 31, 2016	$ —	$ —	$ —	$ —	$ —	$ —
Distributions to partners	—	—	—	—	—	—
Partnership units issued for cash	937	542	—	—	—	1,479
Other, net	—	—	—	—	—	—
Net income	7	5	—	—	—	12
Balance, December 31, 2017	944	547	—	—	—	1,491
Distributions to partners	(44)	(27)	(18)	(11)	—	(100)
Partnership units issued for cash	—	—	436	431	—	867
Other, net	(1)	—	(1)	(1)	—	(3)
Net income	59	36	23	15	—	133
Balance, December 31, 2018	958	556	440	434	—	2,388
Distributions to partners	(59)	(37)	(33)	(34)	(34)	(197)
Partnership units issued for cash	—	—	—	—	780	780
Other, net	—	—	—	—	(1)	(1)
Net income	59	37	33	34	41	204
Balance, December 31, 2019	$ 958	$ 556	$ 440	$ 434	$ 786	$ 3,174

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.

ETO Series E Preferred Units

Distributions on the Series E Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2024, at a rate of 7.600% per annum of the stated liquidation preference of $25. On and after May 15, 2024, distributions on the Series E 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 5.161% per annum. The Series E Preferred Units are redeemable at ETO's option on or after May 15, 2024 at a redemption price of $25 per Series E Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series F Preferred Units

On January 22, 2020, the Partnership issued 500,000 of its 6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units representing limited partner interest in the Partnership, at a price to the public of $1,000 per unit. Distributions on the Series F Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2025, at a rate equal to 6.750% per annum of the $1,000 liquidation preference. On and after May 15, 2025, the distribution rate on the Series F Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.134% per annum. The Series F Preferred Units are redeemable at ETO's option on or after May 15, 2025 at a redemption price of $1,000 per Series F Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

ETO Series G Preferred Units

On January 22, 2020, the Partnership issued 1,100,000 of its 7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units representing limited partner interest in the Partnership, at a price to the public of $1,000 per unit. Distributions on the Series G Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2030, at a rate equal to 7.125% per annum of the $1,000 liquidation preference. On and after May 15, 2030, the distribution rate on the Series G Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.306% per annum. The Series G Preferred Units are redeemable at ETO's option on or after May 15, 2030 at a redemption price of $1,000 per Series G 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

Sunoco LP is party to an equity distribution agreement for an at-the-market ("ATM") offering pursuant to which Sunoco LP may sell its common units from time to time. For the years ended December 31, 2019 and 2018, Sunoco LP issued no units under its ATM program. For the year ended December 31, 2017, Sunoco LP issued an additional 1.3 million units with total net proceeds of $33 million , net of commissions of $0.3 million. As of December 31, 2019, $295 million of Sunoco LP common units remained available to be issued under the currently effective equity distribution agreement.

Sunoco LP's Series A Preferred Units

On March 30, 2017, the Partnership 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 the 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 year ended December 31, 2019 and 2018, distributions of $1 million and $0.6 million, respectively, were reinvested under the USAC distribution reinvestment program resulting in the issuance of approximately 60,584 and 39,280 USAC common units, respectively.

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 automatically converted into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019.

On July 30, 2019, the 6,397,965 USAC Class B units held by the Partnership converted into 6,397,965 common units representing limited partner interests in USAC. These common units participate in distributions declared by USAC.

Cash Distributions

ETO Preferred Unit Distributions

Distributions on the Partnership's Series A, Series B, Series C, Series D and Series E preferred units declared and/or paid by the Partnership were as follows:

Period Ended	Record Date	Payment Date	Series A (1)	Series B (1)	Series C	Series D	Series E
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	—
March 31, 2019	May 1, 2019	May 15, 2019	—	—	0.4609	0.4766	—
June 30, 2019	August 1, 2019	August 15, 2019	31.2500	33.1250	0.4609	0.4766	0.5806 *
September 30, 2019	November 1, 2019	November 15, 2019	—	—	0.4609	0.4766	0.4750
December 31, 2019	February 3, 2020	February 18, 2020	31.2500	33.1250	0.4609	0.4766	0.4750

* Represent prorated initial distributions. Prorated initial distributions on the recently issued Series F and Series G preferred units will be payable in May 2020.

(1) Series A Preferred Units and Series B Preferred Unit distributions are paid on a semi-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, 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
March 31, 2019	May 7, 2019	May 15, 2019	0.8255
June 30, 2019	August 6, 2019	August 14, 2019	0.8255
September 30, 2019	November 5, 2019	November 19, 2019	0.8255
December 31, 2019	February 7, 2020	February 19, 2020	0.8255

USAC Cash Distributions

Subsequent to the Energy Transfer Merger and USAC Transactions described in Note 1 and Note 3, respectively, ETO owned approximately 39.7 million USAC common units and 6.4 million USAC Class B units. Subsequent to the conversion of the USAC Class B Units to USAC common units on July 30, 2019, ETO owns approximately 46.1 million USAC common units. As of December 31, 2019, USAC had approximately 96.6 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding IDRs.

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
March 31, 2019	April 29, 2019	May 10, 2019	0.5250
June 30, 2019	July 29, 2019	August 9, 2019	0.5250
September 30, 2019	October 28, 2019	November 8, 2019	0.5250
December 31, 2019	January 27, 2020	February 7, 2020	0.5250

Accumulated Other Comprehensive Income

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

	December 31, 2019	December 31, 2018
Available-for-sale securities	$ 13	$ 2
Foreign currency translation adjustment	(5)	(5)
Actuarial loss related to pensions and other postretirement benefits	(25)	(48)
Investments in unconsolidated affiliates, net	(1)	9
Total AOCI, net of tax	$ (18)	$ (42)

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

	December 31, 2019	December 31, 2018
Available-for-sale securities	$ (1)	$ (1)
Foreign currency translation adjustment	2	2
Actuarial loss relating to pension and other postretirement benefits	8	12
Total	$ 9	$ 13

8. NON-CASH COMPENSATION PLANS:

ETO Long-Term Incentive Plan

We have previously issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETO Common Units, restricted units, phantom units, distribution equivalent rights (“DERs”), Common Unit appreciation rights, and other unit-based awards.

The Partnership does not currently have any equity compensation plans. In connection with the Energy Transfer Merger in October 2018, all of the Partnership’s equity compensation plans, as well as the Partnership’s obligations under those plans, were assumed by ET. The Partnership recorded stock compensation expenses of $111 million, $105 million and $99 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Subsidiary Long-Term Incentive 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, 2018	2.1	$ 29.15	1.4	$ 14.98
Awards granted	0.7	30.70	0.7	15.88
Awards vested	(0.5)	30.04	(0.3)	13.06
Awards forfeited	(0.2)	28.16	—	16.78
Unvested awards as of December 31, 2019	2.1	29.21	1.8	15.09

The following table summarizes the weighted average grant-date fair value per unit award granted:

	Years Ended December 31,		
	2019	2018	2017
Sunoco LP	$ 30.70	$ 27.67	$ 28.31
USAC	15.88	15.47	N/A

The total fair value of Subsidiary Unit Awards vested for the years ended December 31, 2019, 2018 and 2017 was $17 million, $22 million and $9 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, 2019 and 2018 and Sunoco LP for the year ended December 31, 2017. As of December 31, 2019, estimated compensation cost related to Subsidiary Unit Awards not yet recognized was $57 million, and the weighted average period over which this cost is expected to be recognized in expense is 3.6 years.

9. 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,		
	2019	2018	2017
Current expense (benefit):			
Federal	$ (20)	$ (7)	$ 53
State	(1)	20	(16)
Total	(21)	13	37
Deferred expense (benefit):			
Federal	176	183	(2,025)
State	45	(191)	184
Total	221	(8)	(1,841)
Total income tax expense (benefit)	$ 200	$ 5	$ (1,804)

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 Partnership's income tax benefit for the years ended December 31, 2019, 2018 and 2017 is as follows:

	Years Ended December 31,		
	2019	2018	2017
Income tax expense at United States statutory rate	$ 1,131	$ 849	$ 402
Increase (reduction) in income taxes resulting from:			
Partnership earnings not subject to tax	(940)	(718)	(626)
Federal rate change	—	—	(1,784)
Goodwill impairments	—	—	208
State income taxes (net of federal income tax effects)	14	(125)	123
Dividend received deduction	(3)	(5)	(14)
Change in tax status of subsidiary	—	—	(124)
Other	(2)	4	11
Income tax expense (benefit)	$ 200	$ 5	$ (1,804)

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,	
	2019	2018
Deferred income tax assets:		
Net operating losses, alternative minimum tax credit and other carryforwards	$ 669	$ 768
Pension and other postretirement benefits	—	34
Long-term debt	—	13
Other	62	181
Total deferred income tax assets	731	996
Valuation allowance	(49)	(96)
Net deferred income tax assets	$ 682	$ 900
Deferred income tax liabilities:		
Property, plant and equipment	$ (258)	$ (742)
Investments in affiliates	(3,452)	(2,869)
Trademarks	(72)	(63)
Other	(13)	(110)
Total deferred income tax liabilities	(3,795)	(3,784)
Net deferred income taxes	$ (3,113)	$ (2,884)

As of December 31, 2019, ETP Holdco had a federal net operating loss carryforward of $2.65 billion, of which $1.10 billion will expire in 2031 through 2037 while the remaining can be carried forward indefinitely. As of December 31, 2019, Sunoco Property Company LLC, a corporate subsidiary of Sunoco LP, has no federal net operating loss carryforward.

Our corporate subsidiaries have $15 million of federal alternative minimum tax credits at December 31, 2019, of which $8 million is expected to be reclassified to current income tax receivable in 2020 pursuant to the Tax Cuts and Jobs Act. Our corporate subsidiaries have state net operating loss carryforward benefits of $95 million, net of federal tax, some of which will expire between 2020 and 2038, while others are carried forward indefinitely. A valuation allowance of $49 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,		
	2019	2018	2017
Balance at beginning of year	$ 624	$ 609	$ 615
Additions attributable to tax positions taken in the current year	—	8	—
Additions attributable to tax positions taken in prior years	11	7	28
Reduction attributable to tax positions taken in prior years	(541)	—	(25)
Lapse of statute	—	—	(9)
Balance at end of year	$ 94	$ 624	$ 609

As of December 31, 2019, we have $90 million ($72 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 2019, we recognized interest and penalties of $1 million. At December 31, 2019, we have interest and penalties accrued of $3 million, net of tax.

We appealed the adverse Court of Federal Claims decision against ETC Sunoco regarding the IRS' denial of ethanol blending credits claims under Section 6426 to the Federal Circuit. The Federal Circuit affirmed the CFC's denial on November 1, 2018. ETC Sunoco filed a petition for certiorari with the Supreme Court on May 24, 2019 to review the Federal Circuit's affirmation of the CFC's ruling, and the Court denied Sunoco's petition on October 7, 2019. The petition for certiorari applied to ETC Sunoco's 2004 through 2009 tax years, and 2010 through 2011 are on extension with the IRS through March 30, 2020. Due to the uncertainty surrounding the litigation, a reserve of $530 million was previously established for the full amount of the pending refund claims, and the receivable and reserve for this issue were netted in the consolidated balance sheet. Subsequent to the Supreme Court's denial of the petition in October 2019, the receivable and reserve have been reversed, with no impact to the Partnership's financial position and results of operations.

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. ETC Sunoco 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, ETO and its subsidiaries are no longer subject to examination by the IRS, and most state jurisdictions, for the 2014 and prior tax years.

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

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

FERC Proceedings

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. On August 30, 2019, Panhandle filed a general rate proceeding under Section 4 of the Natural Gas Act. The Natural Gas Act Section 5 and Section 4 proceedings were consolidated by the Order dated October 1, 2019. A hearing in the combined proceedings is scheduled for August 2020, with an initial decision expected in early 2021.

By Order issued February 19, 2019, the FERC initiated a review of Southwest Gas' existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates currently charged by Southwest Gas are just and reasonable and set the matter for hearing. Southwest Gas filed a cost and revenue study on May 6, 2019. On July 10, 2019, Southwest Gas filed an Offer of Settlement in this Section 5 proceeding, which settlement was supported or not opposed by Commission Trial Staff and all active parties. By order dated October 29, 2019, the FERC approved the settlement as filed, and there is not a material impact on revenue.

In addition, on November 30, 2018, Sea Robin filed a rate case pursuant to Section 4 of the Natural Gas Act. On July 22, 2019, Sea Robin filed an Offer of Settlement in this Section 4 proceeding, which settlement was supported or not opposed by Commission Trial Staff and all active parties. By order dated October 17, 2019, the FERC approved the settlement as filed, and there is not a material impact on revenue.

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 rights-of-way ("ROW") commitments, which require fixed payments and either expire upon our chosen abandonment or at various dates in the future. The table below reflects ROW expense included in operating expenses in the accompanying statements of operations:

	Years Ended December 31,		
	2019	2018	2017
ROW expense	$ 45	$ 46	$ 46

PES Refinery Fire and Bankruptcy

We own an approximately 7.4% non-operating interest in PES, which owns a refinery in Philadelphia. In addition, the Partnership provides logistics services to PES under commercial contracts and Sunoco LP has historically purchased refined products from PES. In June 2019, an explosion and fire occurred at the refinery complex.

On July 21, 2019, PES Holdings, LLC and seven of its subsidiaries (collectively, the "Debtors") filed voluntary petitions in the United States Bankruptcy Court for the District of Delaware seeking relief under the provisions of Chapter 11 of the United States Bankruptcy Code, as a result of the explosion and fire at the Philadelphia refinery complex. The Debtors have also defaulted on a $75 million note payable to a subsidiary of the Partnership. The Partnership has not recorded a valuation allowance related to the note receivable as of December 31, 2019, because management is not yet able to determine the collectability of the note in bankruptcy.

In addition, the Partnership's subsidiaries retained certain environmental remediation liabilities when the refinery was sold to PES. As of December 31, 2019, the Partnership has funded these environmental remediation liabilities through its wholly-owned captive insurance company, based upon actuarially determined estimates for such costs, and these liabilities are included in the total environmental liabilities discussed below under "Environmental Remediation." In the event that the PES property is sold in connection with the bankruptcy proceeding, it may be necessary for the Partnership to record additional environmental remediation liabilities in the future depending upon the proposed use of such property by the buyer of the property; however, management is not currently able to estimate such additional liabilities.

PES has rejected certain of the Partnership's commercial contracts pursuant to Section 365 of the Bankruptcy Code; however, the impact of the bankruptcy on the Partnership's commercial contracts and related revenue loss (temporary or permanent) is unknown at this time. In addition, Sunoco LP has been successful at acquiring alternative supplies to replace fuel volume lost from PES and does not anticipate any material impact to its business going forward.

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 27, 2016, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia challenging permits issued by the United States Army Corps of Engineers ("USACE") permitting Dakota Access, LLC ("Dakota Access") to cross the Missouri River at Lake Oahe in North Dakota. The case was subsequently amended to challenge an easement issued by the USACE allowing the pipeline to cross land owned by the USACE adjacent to the Missouri River. Dakota Access and the Cheyenne River Sioux Tribe ("CRST") intervened. Separate lawsuits filed by the Oglala Sioux Tribe ("OST") and the Yankton Sioux Tribe ("YST") were consolidated with this action and several individual tribal members intervened (collectively with SRST and CRST, the "Tribes"). Plaintiffs and Defendants filed cross motions for summary judgment, and the parties await a ruling.

While we believe 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, however, Lone Star is still quantifying the extent of its incurred and ongoing damages and has obtained, and will continue to seek, reimbursement for these losses.

MTBE Litigation

ETC Sunoco Holdings LLC and 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, 2019, Sunoco is a defendant in five cases, including one case each initiated by the States of Maryland 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 ETO, ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals L.P. ("SPMT").

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

On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint related to the Regency-ETO merger (the "Regency Merger") 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.

The Regency Merger Litigation alleges that the Regency Merger breached the Regency partnership agreement. On March 29, 2016, the Delaware Court of Chancery granted the defendants' motion to dismiss the lawsuit in its entirety. Plaintiff appealed, and the Delaware Supreme Court reversed the judgment of the Court of Chancery. Plaintiff then filed an Amended Verified Class Action Complaint, which defendants moved to dismiss. The Court of Chancery granted in part and denied in part the motions to dismiss, dismissing the claims against all defendants other than Regency GP, LP and Regency GP LLC (the "Regency Defendants"). The Court of Chancery later granted Plaintiff's unopposed motion for class certification. Trial was held on December 10-16, 2019, and the parties await a ruling from the court.

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.

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 November 27, 2017, ETO filed a Petition for Review with the Texas Supreme Court. On June 8, 2018, the Texas Supreme Court ordered briefing on the merits. On June 28, 2019, the Texas Supreme Court granted ETO's petition for review and oral argument was heard on October 8, 2019. On January 31, 2020, the Texas Supreme Court affirmed the judgment of the Court of Appeals.

Rover

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and other defendants (collectively, the Defendants") seeking to recover approximately $2.6 million in civil penalties allegedly owed and certain injunctive relief related to permit compliance. The Defendants filed several motions to dismiss, which were granted on all counts. The Ohio EPA appealed, and on December 9, 2019, the Fifth District Court of Appeals entered a unanimous judgment affirming the trial court. The Ohio EPA sought review from the Ohio Supreme Court, which Defendants intend to oppose.

Bayou Bridge

On January 11, 2018, environmental groups and a trade association filed suit against the U.S. Army Corps of Engineers ("USACE") in the United States District Court for the Middle District of Louisiana alleging violations of the National Environmental Policy Act, the Clean Water Act, and the Rivers and Harbors Act. ETO, through its subsidiary Bayou Bridge Pipeline, LLC ("Bayou Bridge"), intervened.

In February 2018, the District Court initially granted Plaintiffs' motion for a preliminary injunction, but the Fifth Circuit Court of Appeals subsequently vacated that decision. The Fifth Circuit's ruling allowed construction to continue and be completed during the pendency of the case. Plaintiffs filed a second motion for preliminary injunction in January 2019, which was denied. Plaintiffs and Defendants filed cross motions for summary judgment, and the parties await a ruling.

Revolution

On September 10, 2018, a pipeline release and fire (the "Incident") occurred on the Revolution pipeline, a natural gas gathering line located in Center Township, Beaver County, Pennsylvania. There were no injuries. On February 8, 2019, the Pennsylvania Department of Environmental Protection ("PADEP") issued a Permit Hold on any requests for approvals/permits or permit amendments for any project in Pennsylvania pursuant to the state's water laws. The Partnership filed an appeal of the Permit Hold with the Pennsylvania Environmental Hearing Board. On January 3, 2020, the Partnership entered into a Consent Order and Agreement with the Department in which, among other things, the Permit Hold was lifted, the Partnership agreed to pay a $28.6 million civil penalty and fund a $2 million community environmental project, and all related appeals were withdrawn.

The Pennsylvania Office of Attorney General has commenced an investigation regarding the Incident, and the United States Attorney for the Western District of Pennsylvania has issued a federal grand jury subpoena for documents relevant to the Incident. The scope of these investigations is not further known at this time.

Chester County, Pennsylvania Investigation

In December 2018, the former Chester County District Attorney ("DA") sent a letter to the Partnership stating that his office was investigating the Partnership and related entities for "potential crimes" related to the Mariner East pipelines.

Subsequently, the matter was submitted to an Investigating Grand Jury in Chester County, Pennsylvania, which has issued subpoenas seeking documents and testimony. On September 24, 2019, the former DA sent a Notice of Intent to the Partnership of its intent to pursue an abatement action if certain conditions were not remediated. The Partnership responded to the Notice of Intent within the proscribed time period. To date, the Partnership is not aware of any further action with regard to this Notice.

In December 2019, the former DA announced charges against a current employee related to the provision of security services. The Partnership has secured independent counsel for the employee. While the Partnership will continue to cooperate with the investigation, it intends to vigorously defend itself.

Delaware County, Pennsylvania Investigation

On March 11, 2019, the Delaware County District Attorney's Office ("DA") announced that the DA and the Pennsylvania Attorney General's Office, at the request of the DA, are conducting an investigation of alleged criminal misconduct involving the construction and related activities of the Mariner East pipelines in Delaware County. The Partnership has not been appraised of the specific conduct under investigation. While the Partnership will cooperate with the investigation, it intends to vigorously defend itself.

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, 2019 and 2018, accruals of approximately $98 million and $53 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.

In addition, other legal proceedings exist that are considered reasonably possible to result in unfavorable outcomes. For those where possible losses can be estimated, the range of possible losses related to these contingent obligations is estimated to be up to $80 million; however, no accruals have been recorded as of December 31, 2019.

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 Louisiana Department of Environmental Quality ("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 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 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma which allegedly occurred in January 2015. In January 2019, a 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. Subsequently, the court approved the Consent Decree and the penalty payment of $5.4 million was satisfied. 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 related to the Caddo Parish, Louisiana release.

In October 2018, Pipeline Hazardous Materials Safety Administration ("PHMSA") issued a notice of proposed safety order (the "Notice") to SPMT, a wholly owned subsidiary of ETO. The Notice alleged that conditions exist on certain pipeline facilities owned and operated by SPMT in Nederland, Texas that pose a pipeline integrity risk to public safety, property or the environment. The Notice also made preliminary findings of fact and proposed corrective measures. SPMT responded to the Notice by submitting a timely written response on November 2, 2018, attended an informal consultation held on January 30, 2019 and entered into a consent agreement with PHMSA resolving the issues in the Notice as of March 2019. SPMT is currently awaiting response from PHMSA regarding the approval status of the submitted Remedial Work Plan.

On June 4, 2019, the Oklahoma Corporation Commission's ("OCC") Transportation Division filed a complaint against SPLP seeking a penalty of up to $1 million related to a May 2018 rupture near Edmond, Oklahoma. The release occurred on the Noble to Douglas 8" pipeline in an area of external corrosion and caused the release of approximately fifteen barrels of crude oil. SPLP responded immediately to the release and remediated the surrounding environment and pipeline in cooperation with the OCC. The OCC filed the complaint alleging that SPLP failed to provide adequate cathodic protection to the pipeline causing the failure. SPLP is negotiating a settlement agreement with the OCC for a lesser penalty. The OCC has accepted our counter offer in conjunction with a proposed consent order. The Consent Order will be presented to the OCC at a final hearing the date of which is to be determined.

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 be contractually 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 that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that Sunoco no longer operates, closed and/or sold refineries and other formerly owned sites.

  Sunoco is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of December 31, 2019, Sunoco had been named as a PRP at approximately 40 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. Sunoco is usually one of a number of companies identified as a PRP at a site. Sunoco has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco’s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

To the extent estimable, expected remediation costs are included in the amounts recorded for environmental matters in our consolidated balance sheets. In some circumstances, future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. To the extent that an environmental remediation obligation is recorded by a subsidiary that applies regulatory accounting policies, amounts that are expected to be recoverable through tariffs or rates are recorded as regulatory assets on our consolidated balance sheets.

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. 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,	
	2019	2018
Current	$ 43	$ 42
Non-current	274	295
Total environmental liabilities	$ 317	$ 337

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

During the years ended December 31, 2019 and 2018, the Partnership recorded $39 million and $48 million, respectively, of expenditures related to environmental cleanup programs.

Our pipeline operations are subject to regulation by the United States Department of Transportation under PHMSA, pursuant to which PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. 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.

11. REVENUE:

The following disclosures discuss the Partnership's revised revenue recognition policies upon the adoption of ASU 2014-09 on January 1, 2018. These policies were applied to the amounts reflected in the Partnership's consolidated financial statements for the years ended December 31, 2019 and 2018, while the amounts reflected in the Partnership's consolidated financial statements for the year ended December 31, 2017 were recorded under the Partnership's previous accounting policies.

Disaggregation of revenue

The major types of revenue within 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;
  - 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 2019 and 2018 and ASC Topic 605 for 2017.

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.

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.

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. 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.

Our midstream segment also generates revenues from the sale of residue gas and NGLs at the tailgate of our processing facilities primarily to affiliates and some third-party customers.

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 services segment revenues are primarily derived from providing 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.

The following table summarizes the consolidated activity of our contract liabilities:

	Contract Liabilities
Balance, January 1, 2018	$ 221
Additions	765
Revenue recognized	(592)
Balance, December 31, 2018	394
Additions	643
Revenue recognized	(679)
Balance, December 31, 2019	$ 358

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 balances of Sunoco LP's contract assets and contract liabilities as of December 31, 2019 and 2018 were as follows:

	December 31, 2019	December 31, 2018
Contract balances:		
Contract asset	$ 117	$ 75
Accounts receivable from contracts with customers	366	347
Contract liability	—	1

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 current assets and other non-current 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 Sunoco LP recognized for the years ended December 31, 2019 and 2018 was $17 million and $14 million, respectively. 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.

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, 2019, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations is $40.70 billion and the Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	Years Ending December 31,				
	2020	2021	2022	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of December 31, 2019	$ 5,913	$ 5,056	$ 4,672	$ 25,059	$ 40,700

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.

12. LEASE ACCOUNTING:

Lessee Accounting

The Partnership leases terminal facilities, tank cars, office space, land and equipment under non-cancelable operating leases whose initial terms are typically five to 15 years, with some real estate leases having terms of 40 years or more, along with options that permit renewals for additional periods. At the inception of each, we determine if the arrangement is a lease or contains an embedded lease and review the facts and circumstances of the arrangement to classify lease assets as operating or finance leases under Topic 842. The Partnership has elected not to record any leases with terms of 12 months or less on the balance sheet.

At present, the majority of the Partnership's active leases are classified as operating in accordance with Topic 842. Balances related to operating leases are included in operating lease ROU assets, accrued and other current liabilities, operating lease current liabilities and non-current operating lease liabilities in our consolidated balance sheets. Finance leases represent a small portion of the active lease agreements and are included in finance lease ROU assets, current maturities of long-term debt and long-term debt, less current maturities in our consolidated balance sheets. The ROU assets represent the Partnership's right to use an underlying asset for the lease term and lease liabilities represent the obligation of the Partnership to make minimum lease payments arising from the lease for the duration of the lease term.

Most leases include one or more options to renew, with renewal terms that can extend the lease term from one to 20 years or greater. The exercise of lease renewal options is typically at the sole discretion of the Partnership and lease extensions are evaluated on a lease-by-lease basis. Leases containing early termination clauses typically require the agreement of both parties to the lease. At the inception of a lease, all renewal options reasonably certain to be exercised are considered when determining the lease term. Presently, the Partnership does not have leases that include options to purchase or automatic transfer of ownership of the leased property to the Partnership. The depreciable life of lease assets and leasehold improvements are limited by the expected lease term.

To determine the present value of future minimum lease payments, we use the implicit rate when readily determinable. Presently, because many of our leases do not provide an implicit rate, the Partnership applies its incremental borrowing rate based on the information available at the lease commencement date to determine the present value of minimum lease payments. The operating and finance lease ROU assets include any lease payments made and exclude lease incentives.

Minimum rent payments are expensed on a straight-line basis over the term of the lease. In addition, some leases require additional contingent or variable lease payments, which are based on the factors specific to the individual agreement. Variable lease payments the Partnership is typically responsible for include payment of real estate taxes, maintenance expenses and insurance.

For short-term leases (leases that have term of twelve months or less upon commencement), lease payments are recognized on a straight-line basis and no ROU assets are recorded.

The components of operating and finance lease amounts recognized in the accompanying consolidated balance sheet as of December 31, 2019 were as follows:

	December 31, 2019
Operating leases:	
Lease right-of-use assets, net	$ 848
Operating lease current liabilities	54
Accrued and other current liabilities	1
Non-current operating lease liabilities	816
Finance leases:	
Property, plant and equipment, net	$ 1
Lease right-of-use assets, net	29
Accrued and other current liabilities	1
Current maturities of long-term debt	6
Long-term debt, less current maturities	26
Other non-current liabilities	2

The components of lease expense for the year ended December 31, 2019 were as follows:

	Income Statement Location	Year Ended December 31, 2019
Operating lease costs:		
Operating lease cost	Cost of goods sold	$ 28
Operating lease cost	Operating expenses	72
Operating lease cost	Selling, general and administrative	16
Total operating lease costs		116
Finance lease costs:		
Amortization of lease assets	Depreciation, depletion and amortization	6
Interest on lease liabilities	Interest expense, net of capitalized interest	1
Total finance lease costs		7
Short-term lease cost	Operating expenses	42
Variable lease cost	Operating expenses	17
Lease costs, gross		182
Less: Sublease income	Other revenue	47
Lease costs, net		$ 135

The weighted average remaining lease terms and weighted average discount rates as of December 31, 2019 were as follows:

	December 31, 2019
Weighted-average remaining lease term (years):	
Operating leases	22
Finance leases	5
Weighted-average discount rate (%):	
Operating leases	5%
Finance leases	5%

Cash flows and non-cash activity related to leases for the year ended December 31, 2019 were as follows:

	Year Ended December 31, 2019
Operating cash flows from operating leases	$ (158)
Lease assets obtained in exchange for new finance lease liabilities	28
Lease assets obtained in exchange for new operating lease liabilities	39

Maturities of lease liabilities as of December 31, 2019 are as follows:

	Operating leases	Finance leases	Total
2020	$ 98	$ 8	$ 106
2021	89	8	97
2022	77	8	85
2023	71	7	78
2024	68	4	72
Thereafter	1,141	5	1,146
Total lease payments	1,544	40	1,584
Less: present value discount	674	5	679
Present value of lease liabilities	$ 870	$ 35	$ 905

Lessor Accounting

The Partnership leases or subleases a portion of its real estate portfolio to third-party companies as a stable source of long-term revenue. Our lessor and sublease portfolio consists mainly of operating leases with convenience store operators. At this time, most lessor agreements contain five-year terms with renewal options to extend and early termination options based on established terms specific to the individual agreement.

Rental income included in other revenue in our consolidated statement of operations for the year ended December 31, 2019 was $146 million.

Future minimum operating lease payments receivable as of December 31, 2019 are as follows:

	Lease Payments
2020	$ 125
2021	99
2022	62
2023	7
2024	2
Thereafter	7
Total undiscounted cash flows	$ 302

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, 2019		December 31, 2018	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	1,483	2020	468	2019
Basis Swaps IFERC/NYMEX[(1)]	(35,208)	2020-2024	16,845	2019-2020
Options – Puts	—	—	10,000	2019
Power (Megawatt):				
Forwards	3,213,450	2020-2029	3,141,520	2019
Futures	(353,527)	2020	56,656	2019-2021
Options – Puts	51,615	2020	18,400	2019
Options – Calls	(2,704,330)	2020-2021	284,800	2019
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(18,923)	2020-2022	(30,228)	2019-2021
Swing Swaps IFERC	(9,265)	2020	54,158	2019-2020
Fixed Swaps/Futures	(3,085)	2020-2021	(1,068)	2019-2021
Forward Physical Contracts	(13,364)	2020-2021	(123,254)	2019-2020
NGL (MBbls) – Forwards/Swaps	(1,300)	2020-2021	(2,135)	2019
Crude (MBbls) – Forwards/Swaps	4,465	2020	20,888	2019
Refined Products (MBbls) – Futures	(2,473)	2020-2021	(1,403)	2019
Corn (thousand bushels)	(1,210)	2020	(1,920)	2019
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(31,780)	2020	(17,445)	2019
Fixed Swaps/Futures	(31,780)	2020	(17,445)	2019
Hedged Item – Inventory	31,780	2020	17,445	2019

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

Interest Rate Risk

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

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

		Notional Amount Outstanding	
Term	Type [1]	December 31, 2019	December 31, 2018
March 2019	Pay a floating rate and receive a fixed rate of 1.42%	$ —	$ 300
July 2019 [2]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	—	400
July 2020 [2][3]	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	400
July 2022 [2]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	400	—

(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.

(3) The July 2020 interest rate swaps were terminated in January 2020.

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, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 24	$ —	$ —	$ (13)
	24	—	—	(13)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	319	402	(350)	(397)
Commodity derivatives	41	158	(39)	(173)
Interest rate derivatives	—	—	(399)	(163)
	360	560	(788)	(733)
Total derivatives	$ 384	$ 560	$ (788)	$ (746)

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, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (399)	$ (163)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	41	158	(39)	(173)
Broker cleared derivative contracts	Other current assets (liabilities)	343	402	(350)	(410)
		384	560	(788)	(746)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(18)	(47)	18	47
Counterparty netting	Other current assets (liabilities)	(318)	(397)	318	397
Total net derivatives		$ 48	$ 116	$ (452)	$ (302)

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,		
		2019	2018	2017
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$ —	$ (3)	$ 26

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2019	2018	2017
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Cost of products sold	$ 21	$ 32	$ 31
Commodity derivatives – Non-trading	Cost of products sold	(78)	(102)	5
Interest rate derivatives	Gains (losses) on interest rate derivatives	(241)	47	(37)
Embedded derivatives	Other, net	—	—	1
Total		$ (298)	$ (23)	$ —

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 $66 million, $62 million and $59 million to these 401(k) savings plans for the years ended December 31, 2019, 2018 and 2017, respectively.

Pension and Other Postretirement Benefit Plans

Panhandle

Postretirement benefits expense for the years ended December 31, 2019, 2018 and 2017 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 closed group of former employees based on certain criteria.

ETC Sunoco

ETC Sunoco 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 ETC Sunoco. and its retirees. Access to postretirement medical benefits was phased out or eliminated for all employees retiring after July 1, 2010. In March, 2012, ETC Sunoco established a trust for its postretirement benefit liabilities. ETC Sunoco made a tax-deductible contribution of approximately $200 million to the trust. The funding of the trust eliminated substantially all of ETC Sunoco's future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2019			December 31, 2018		
	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	$ 37	$ 198	$ 1	$ 47	$ 156
Service cost	—	—	1	—	—	1
Interest cost	—	1	7	—	1	5
Amendments	—	—	—	—	—	60
Benefits paid, net	—	(7)	(16)	—	(7)	(17)
Actuarial (gain) loss and other	—	—	18	—	(4)	(7)
Benefit obligation at end of period	1	31	208	1	37	198
Change in plan assets:						
Fair value of plan assets at beginning of period	1	—	241	1	—	257
Return on plan assets and other	—	—	35	—	—	(8)
Employer contributions	—	—	10	—	—	9
Benefits paid, net	—	—	(16)	—	—	(17)
Fair value of plan assets at end of period	1	—	270	1	—	241
Amount underfunded (overfunded) at end of period	$ —	$ 31	$ (62)	$ —	$ 37	$ (43)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$ —	$ —	$ 88	$ —	$ —	$ 68
Current liabilities	—	(5)	(2)	—	(6)	(2)
Non-current liabilities	—	(26)	(24)	—	(31)	(23)
	$ —	$ (31)	$ 62	$ —	$ (37)	$ 43
Amounts recognized in accumulated other comprehensive income (loss) (pre-tax basis) consist of:						
Net actuarial gain (loss)	$ —	$ 1	$ (5)	$ —	$ 1	$ (7)
Prior service cost	—	—	40	—	—	66
	$ —	$ 1	$ 35	$ —	$ 1	$ 59

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

	December 31, 2019			December 31, 2018		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$ —	$ 31	N/A	$ —	$ 37	N/A
Accumulated benefit obligation	1	31	208	1	37	198
Fair value of plan assets	1	—	270	1	—	241

Components of Net Periodic Benefit Cost

	December 31, 2019		December 31, 2018	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$ —	$ 1	$ —	$ 1
Interest cost	1	7	1	5
Expected return on plan assets	—	(10)	—	(10)
Prior service cost amortization	—	26	—	16
Net periodic benefit cost	$ 1	$ 24	$ 1	$ 12

Assumptions

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

	December 31, 2019		December 31, 2018	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	4.07%	2.71%	4.02%	3.40%
Rate of compensation increase	—	—	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, 2019		December 31, 2018	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	3.29%	3.76%	3.52%	3.51%
Expected return on assets:				
Tax exempt accounts	3.26%	7.00%	3.26%	6.63%
Taxable accounts	—	4.75%	N/A	4.50%
Rate of compensation increase	—	—	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 weighted-average rates used to measure the expected cost of benefits covered by the plans are shown in the table below:

	December 31,	
	2019	2018
Health care cost trend rate	7.25%	7.15%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.83%	4.82%
Year that the rate reaches the ultimate trend rate	2026	2024

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 ETC Sunoco funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns and maintain a sufficient funded status of the plans. In anticipation of the pension plan termination, ETC Sunoco 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, 2019		
	Fair Value Total	Level 1	Level 2	Level 3
Mutual funds[1]	$ 1	$ 1	$ —	$ —

[1] Comprised of approximately 100% equities as of December 31, 2019.

		Fair Value Measurements at December 31, 2018		
	Fair Value Total	Level 1	Level 2	Level 3
Mutual funds[1]	$ 1	$ 1	$ —	$ —

[1] Comprised of approximately 100% equities as of December 31, 2018.

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

		Fair Value Measurements at December 31, 2019		
	Fair Value Total	Level 1	Level 2	Level 3
Asset category:				
Cash and cash equivalents	$ 14	$ 14	$ —	$ —
Mutual funds[1]	177	177	—	—
Fixed income securities	79	—	79	—
Total	$ 270	$ 191	$ 79	$ —

[1] Primarily comprised of approximately 59% equities, 40% fixed income securities and 1% cash as of December 31, 2019.

		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.

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 $5 million to pension plans and $8 million to other postretirement plans in 2020. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

Panhandle and ETC Sunoco's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

Years	Pension Benefits - Unfunded Plans [(1)]	Other Postretirement Benefits (Gross, Before Medicare Part D)
2020	$ 5	$ 20
2021	5	20
2022	4	19
2023	4	18
2024	3	15
2025 - 2029	10	67

(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 7.

ET-ETO Long-Term Notes

In October 2018, in connection with the Energy Transfer Merger, ET and ETO entered into an intercompany promissory note ("ET-ETO Promissory Note A") for an aggregate amount up to $2.20 billion that accrues interest at a weighted average rate based on interest payable by ETO on its outstanding indebtedness. The balance outstanding on this note receivable from ET as of December 31, 2018 was $440 million. On August 19, 2019, the entire outstanding balance of $268 million was paid off.

In March 2019, in connection with the ET-ETO senior notes exchange, ET and ETO entered into an intercompany promissory note ("ET-ETO Promissory Note B") for an aggregate amount up to $4.25 billion that accrues interest at a weighted average rate based on interest payable by ETO on its outstanding indebtedness. The ET-ETO Promissory Note B matures on December 31, 2024. As of December 31, 2019 the ET-ETO Promissory Note B had an outstanding balance of $3.71 billion.

As of December 31, 2019, ETO has a long-term intercompany payable due to ET of $104 million, which has been netted against the outstanding promissory notes receivable in our consolidated balance sheet.

ETO-SemGroup Long-Term Notes

In December 2019, in connection with the SemGroup acquisition, ETO and SemGroup entered into an intercompany promissory note for an aggregate amount up to $2.5 billion that accrues interest at 5.20% per annum. The ETO-SemGroup promissory note matures on December 31, 2029. As of December 31, 2019 the ETO-SemGroup Promissory Note B had an outstanding balance of $2.32 billion.

For the year ended December 31, 2019, ETO recognized $191 million in interest income related to these notes, recorded in Other, net on its consolidated statements of operations.

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 revenues from related companies on our consolidated statements of operations:

	Years Ended December 31,		
	2019	2018	2017
Revenues from related companies	$ 492	$ 431	$ 303

The following table summarizes the related company accounts receivable and accounts payable balances on our consolidated balance sheets:

	December 31,	
	2019	2018
Accounts receivable from related companies:		
ET	$ 8	$ 65
FGT	50	25
Phillips 66	36	42
Traverse Rover LLC	42	—
Other	39	44
Total accounts receivable from related companies	$ 175	$ 176
Accounts payable to related companies:		
ET	$ —	$ 59
Other	27	60
Total accounts payable to related companies	$ 27	$ 119

16. REPORTABLE SEGMENTS:

Our reportable segments 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.

Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

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 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 total Partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Segment Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

The following tables present financial information by segment:

	Years Ended December 31,		
	2019	2018	2017
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$ 2,749	$ 3,428	$ 2,891
Intersegment revenues	350	309	192
	3,099	3,737	3,083
Interstate transportation and storage:			
Revenues from external customers	1,941	1,664	1,112
Intersegment revenues	22	18	19
	1,963	1,682	1,131
Midstream:			
Revenues from external customers	2,268	2,090	2,510
Intersegment revenues	3,751	5,432	4,433
	6,019	7,522	6,943
NGL and refined products transportation and services:			
Revenues from external customers	9,920	10,119	7,885
Intersegment revenues	1,721	1,004	763
	11,641	11,123	8,648
Crude oil transportation and services:			
Revenues from external customers	18,307	17,236	11,672
Intersegment revenues	—	96	31
	18,307	17,332	11,703
Investment in Sunoco LP:			
Revenues from external customers	16,590	16,982	11,713
Intersegment revenues	6	12	10
	16,596	16,994	11,723
Investment in USAC:			
Revenues from external customers	678	495	—
Intersegment revenues	20	13	—
	698	508	—
All other:			
Revenues from external customers	1,579	2,073	2,740
Intersegment revenues	81	155	161
	1,660	2,228	2,901
Eliminations	(5,951)	(7,039)	(5,609)
Total revenues	$ 54,032	$ 54,087	$ 40,523

	Years Ended December 31,		
	2019	2018	2017
Cost of products sold:			
Intrastate transportation and storage	$ 1,909	$ 2,665	$ 2,327
Midstream	3,570	5,145	4,761
NGL and refined products transportation and services	8,393	8,462	6,508
Crude oil transportation and services	14,649	14,439	9,826
Investment in Sunoco LP	15,380	15,872	10,615
Investment in USAC	91	67	—
All other	1,496	2,006	2,509
Eliminations	(5,885)	(6,998)	(5,580)
Total cost of products sold	$ 39,603	$ 41,658	$ 30,966

	Years Ended December 31,		
	2019	2018	2017
Depreciation, depletion and amortization:			
Intrastate transportation and storage	$ 184	$ 169	$ 147
Interstate transportation and storage	387	334	254
Midstream	1,065	1,006	954
NGL and refined products transportation and services	613	466	401
Crude oil transportation and services	430	445	402
Investment in Sunoco LP	181	167	169
Investment in USAC	231	169	—
All other	33	87	214
Total depreciation, depletion and amortization	$ 3,124	$ 2,843	$ 2,541

	Years Ended December 31,		
	2019	2018	2017
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ 18	$ 19	$ (156)
Interstate transportation and storage	222	227	236
Midstream	20	26	20
NGL and refined products transportation and services	51	64	33
Crude oil transportation and services	(3)	6	4
All other	(10)	2	7
Total equity in earnings of unconsolidated affiliates	$ 298	$ 344	$ 144

	Years Ended December 31,		
	2019	2018	2017
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 999	$ 927	$ 626
Interstate transportation and storage	1,792	1,680	1,274
Midstream	1,599	1,627	1,481
NGL and refined products transportation and services	2,663	1,979	1,641
Crude oil transportation and services	2,949	2,330	1,379
Investment in Sunoco LP	665	638	732
Investment in USAC	420	289	—
All other	104	76	219
Total Segment Adjusted EBITDA	11,191	9,546	7,352
Depreciation, depletion and amortization	(3,124)	(2,843)	(2,541)
Interest expense, net of interest capitalized	(2,257)	(1,709)	(1,575)
Impairment losses	(74)	(431)	(1,039)
Gains (losses) on interest rate derivatives	(241)	47	(37)
Non-cash compensation expense	(111)	(105)	(99)
Unrealized gains (losses) on commodity risk management activities	(4)	(11)	59
Inventory valuation adjustments	79	(85)	24
Losses on extinguishments of debt	(2)	(109)	(42)
Adjusted EBITDA related to unconsolidated affiliates	(621)	(655)	(716)
Equity in earnings of unconsolidated affiliates	298	344	144
Impairment of investments in unconsolidated affiliates	—	—	(313)
Adjusted EBITDA related to discontinued operations	—	25	(223)
Other, net	252	30	154
Income from continuing operations before income tax expense	5,386	4,044	1,148
Income tax expense from continuing operations	(200)	(5)	1,804
Income from continuing operations	5,186	4,039	2,952
Loss from discontinued operations, net of income taxes	—	(265)	(177)
Net income	$ 5,186	$ 3,774	$ 2,775

	December 31,		
	2019	2018	2017
Segment assets:			
Intrastate transportation and storage	$ 6,648	$ 6,365	$ 5,020
Interstate transportation and storage	18,111	15,081	15,316
Midstream	20,070	19,745	20,004
NGL and refined products transportation and services	19,145	18,267	17,600
Crude oil transportation and services	18,915	18,022	17,730
Investment in Sunoco LP	5,438	4,879	8,344
Investment in USAC	3,730	3,775	—
All other and eliminations	6,468	2,308	2,470
Total segment assets	$ 98,525	$ 88,442	$ 86,484

	Years Ended December 31,		
	2019	2018	2017
Additions to property, plant and equipment [1]:			
Intrastate transportation and storage	$ 124	$ 344	$ 175
Interstate transportation and storage	375	812	728
Midstream	826	1,161	1,308
NGL and refined products transportation and services	2,976	2,381	2,971
Crude oil transportation and services	392	474	453
Investment in Sunoco LP	148	103	103
Investment in USAC	200	205	—
All other	213	150	268
Total additions to property, plant and equipment [1]	$ 5,254	$ 5,630	$ 6,006

[1] Excluding acquisitions, net of contributions in aid of construction costs (capital expenditures related to the Partnership's proportionate ownership on an accrual basis).

	December 31,		
	2019	2018	2017
Advances to and investments in unconsolidated affiliates:			
Intrastate transportation and storage	$ 88	$ 83	$ 85
Interstate transportation and storage	2,524	2,070	2,118
Midstream	112	124	126
NGL and refined products transportation and services	243	243	234
Crude oil transportation and services	24	28	22
All other	27	88	113
Total advances to and investments in unconsolidated affiliates	$ 3,018	$ 2,636	$ 2,698

17. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total Year
2019:					
Revenues	$ 13,121	$ 13,877	$ 13,495	$ 13,539	$ 54,032
Operating income	1,928	1,827	1,834	1,696	7,285
Net income	1,281	1,281	1,224	1,400	5,186
Net income attributable to partners	1,012	1,002	951	1,119	4,084

	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	1,105	1,138	1,715	1,444	5,402
Income from continuing operations	814	760	1,494	971	4,039
Net income	577	734	1,492	971	3,774
Net income attributable to partners	715	432	1,135	743	3,025

18. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

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

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

The following supplemental condensed consolidating financial information reflects the Parent Guarantor's separate accounts, the Subsidiary Issuer's separate accounts, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and the Parent Guarantor's consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent Guarantor's investments in its subsidiaries and the Subsidiary Issuer's investments in its subsidiaries are accounted for under the equity method of accounting.

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

	December 31, 2019				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ —	$ 253	$ —	$ 253
All other current assets	4,905	44,047	45,997	(88,042)	6,907
Property, plant and equipment	—	—	69,971	—	69,971
Investments in unconsolidated affiliates	57,383	15,045	3,033	(72,443)	3,018
All other assets	5,786	131	12,459	—	18,376
Total assets	$ 68,074	$ 59,223	$ 131,713	$ (160,485)	$ 98,525
Current liabilities	$ 3,394	$ 41,148	$ 48,350	$ (85,811)	$ 7,081
Non-current liabilities	34,782	7,602	13,753	—	56,137
Noncontrolling interests	—	—	8,018	—	8,018
Total partners' capital	29,898	10,473	61,592	(74,674)	27,289
Total liabilities and equity	$ 68,074	$ 59,223	$ 131,713	$ (160,485)	$ 98,525

	December 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ —	$ 418	$ —	$ 418
All other current assets	4,070	36,889	73,336	(107,893)	6,402
Property, plant and equipment	—	—	66,655	—	66,655
Investments in unconsolidated affiliates	51,876	13,090	2,636	(64,966)	2,636
All other assets	12	75	12,244	—	12,331
Total assets	$ 55,958	$ 50,054	$ 155,289	$ (172,859)	$ 88,442
Current liabilities	$ 3,430	$ 33,517	$ 80,731	$ (108,381)	$ 9,297
Non-current liabilities	24,787	7,605	10,132	—	42,524
Noncontrolling interests	—	—	7,903	—	7,903
Total partners' capital	27,741	8,932	56,523	(64,478)	28,718
Total liabilities and equity	$ 55,958	$ 50,054	$ 155,289	$ (172,859)	$ 88,442

	Year Ended December 31, 2019				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 54,032	$ —	$ 54,032
Operating costs, expenses, and other	—	—	46,747	—	46,747
Operating income	—	—	7,285	—	7,285
Interest expense, net	(1,612)	(374)	(271)	—	(2,257)
Equity in earnings of unconsolidated affiliates	5,623	1,938	298	(7,561)	298
Losses on debt extinguishment	—	—	(2)		(2)
Losses on interest rate derivatives	(241)	—	—	—	(241)
Other, net	314	3	(14)	—	303
Income before income tax expense	4,084	1,567	7,296	(7,561)	5,386
Income tax expense	—	—	200	—	200
Net income	4,084	1,567	7,096	(7,561)	5,186
Less: Net income attributable to noncontrolling interests	—	—	1,051	—	1,051
Less: Net income attributable to redeemable noncontrolling interests			51		51
Net income attributable to partners	$ 4,084	$ 1,567	$ 5,994	$ (7,561)	$ 4,084
Other comprehensive income	$ —	$ —	$ 24	$ —	$ 24
Comprehensive income	4,084	1,567	7,120	(7,561)	5,210
Comprehensive income attributable to noncontrolling interests	—	—	1,051	—	1,051
Comprehensive income attributable to redeemable noncontrolling interests			51		51
Comprehensive income attributable to partners	$ 4,084	$ 1,567	$ 6,018	$ (7,561)	$ 4,108

	Year Ended December 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 54,087	$ —	$ 54,087
Operating costs, expenses, and other	—	—	48,685	—	48,685
Operating income	—	—	5,402	—	5,402
Interest expense, net	(1,196)	(176)	(337)	—	(1,709)
Equity in earnings of unconsolidated affiliates	4,170	1,430	344	(5,600)	344
Losses on extinguishments of debt	—	—	(109)	—	(109)
Gains on interest rate derivatives	47	—	—	—	47
Other, net	—	—	69	—	69
Income from continuing operations before income tax expense	3,021	1,254	5,369	(5,600)	4,044
Income tax expense from continuing operations	—	—	5	—	5
Net income from continuing operations	3,021	1,254	5,364	(5,600)	4,039
Loss from discontinued operations, net of income taxes	—	—	(265)	—	(265)
Net income	3,021	1,254	5,099	(5,600)	3,774
Less: Net income attributable to noncontrolling interests	—	—	715	—	715
Less: Net income attributable to redeemable noncontrolling interests	—	—	39	—	39
Less: Net loss attributable to predecessor	—	—	(5)	—	(5)
Net income attributable to partners	$ 3,021	$ 1,254	$ 4,350	$ (5,600)	$ 3,025
Other comprehensive loss	$ —	$ —	$ (43)	$ —	$ (43)
Comprehensive income	3,021	1,254	5,056	(5,600)	3,731
Less: Comprehensive income attributable to noncontrolling interests	—	—	715	—	715
Less: Comprehensive income attributable to redeemable noncontrolling interests	—	—	39	—	39
Less: Comprehensive loss attributable to predecessor	—	—	(5)	—	(5)
Comprehensive income attributable to partners	$ 3,021	$ 1,254	$ 4,307	$ (5,600)	$ 2,982

	Year Ended December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 40,523	$ —	$ 40,523
Operating costs, expenses, and other	—	1	37,757	—	37,758
Operating income (loss)	—	(1)	2,766	—	2,765
Interest expense, net	—	(156)	(1,419)	—	(1,575)
Equity in earnings of unconsolidated affiliates	2,564	1,242	144	(3,806)	144
Impairment of investments in unconsolidated affiliates	—	—	(313)	—	(313)
Losses on extinguishments of debt	—	—	(42)	—	(42)
Losses on interest rate derivatives	—	—	(37)	—	(37)
Other, net	—	—	207	(1)	206
Income from continuing operations before income tax benefit	2,564	1,085	1,306	(3,807)	1,148
Income tax benefit from continuing operations	—	—	(1,804)	—	(1,804)
Net income from continuing operations	2,564	1,085	3,110	(3,807)	2,952
Loss from discontinued operations, net of income taxes	—	—	(177)	—	(177)
Net income	2,564	1,085	2,933	(3,807)	2,775
Less: Net income attributable to noncontrolling interests	—	—	420	—	420
Less: Net income attributable to predecessor	—	—	274	—	274
Net income attributable to partners	$ 2,564	$ 1,085	$ 2,239	$ (3,807)	$ 2,081
Other comprehensive loss	$ —	$ —	$ (5)	$ —	$ (5)
Comprehensive income	2,564	1,085	2,928	(3,807)	2,770
Less: Comprehensive income attributable to noncontrolling interests	—	—	420	—	420
Less: Comprehensive income attributable to predecessor	—	—	274	—	274
Comprehensive income attributable to partners	$ 2,564	$ 1,085	$ 2,234	$ (3,807)	$ 2,076

	Year Ended December 31, 2019				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 3,372	$ 2,732	$ 8,988	$ (6,841)	$ 8,251
Cash flows used in investing activities	(2,044)	(2,732)	(8,188)	6,841	(6,123)
Cash flows used in financing activities	(1,328)	—	(965)	—	(2,293)
Change in cash	—	—	(165)	—	(165)
Cash at beginning of period	—	—	418	—	418
Cash at end of period	$ —	$ —	$ 253	$ —	$ 253

	Year Ended December 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 4,041	$ 1,521	$ 5,641	$ (3,644)	$ 7,559
Cash flows used in investing activities	(3,408)	(1,519)	(5,619)	3,644	(6,902)
Cash flows provided by (used in) financing activities	(633)	—	(2,675)	—	(3,308)
Net increase in cash and cash equivalents of discontinued operations	—	—	2,734	—	2,734
Change in cash	—	2	81	—	83
Cash at beginning of period	—	(2)	337	—	335
Cash at end of period	$ —	$ —	$ 418	$ —	$ 418

	Year Ended December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 2,564	$ 1,047	$ 5,013	$ (3,807)	$ 4,817
Cash flows used in investing activities	(2,240)	(1,368)	(5,811)	3,807	(5,612)
Cash flows provided by financing activities	(324)	277	619	—	572
Net decrease in cash and cash equivalents of discontinued operations	—	—	93	—	93
Change in cash	—	(44)	(86)	—	(130)
Cash at beginning of period	—	42	423	—	465
Cash at end of period	$ —	$ (2)	$ 337	$ —	$ 335