Energy Transfer Partners, L.P.
Form 10-K
February 29, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR

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

Commission file number 1-11727
ENERGY TRANSFER PARTNERS, 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	Name of each exchange on which registered
Common Units	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý 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 ý
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 ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filer ý Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ¨ No ý

The aggregate market value as of June 30, 2015, of the registrant’s Common Units held by non-affiliates of the registrant, based on the reported closing price of such Common Units on the New York Stock Exchange on such date, was $24.43 billion. Common Units held by each executive officer and director and by each person who owns 5% or more of the outstanding Common Units have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

At February 19, 2016, the registrant had 507,740,653 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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Forward-Looking Statements

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

Definitions

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

/d	per day
AmeriGas	AmeriGas Partners, L.P.
AOCI	accumulated other comprehensive income (loss)
Aqua – PVR	Aqua – PVR Water Services, LLC
AROs	asset retirement obligations
Bbls	barrels
Bcf	billion cubic feet
BG	BG Group plc
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
Citrus	Citrus, LLC
Coal Handling	Coal Handling Solutions LLC, Kingsport Handling LLC, and Kingsport Services LLC, now known as Materials Handling Solutions LLC
CrossCountry	CrossCountry Energy, LLC

DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
Eagle Rock	Eagle Rock Energy Partners, L.P.
ELG	Edwards Lime Gathering LLC
EPA	U.S. Environmental Protection Agency
ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC

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ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC
ETE Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ET Interstate	Energy Transfer Interstate Holdings, LLC
ETP Credit Facility	ETP's $3.75 billion revolving credit facility
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP Holdco	ETP Holdco Corporation
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
Gulf States	Gulf States Transmission LLC
HPC	RIGS Haynesville Partnership Co.
HOLP	Heritage Operating, L.P.
Hoover Energy	Hoover Energy Partners, LP
IDRs	incentive distribution rights
KMI	Kinder Morgan Inc.
Lake Charles LNG	Lake Charles LNG Company, LLC (previously named Trunkline LNG Company, LLC), a subsidiary of ETE
LCL	Lake Charles LNG Export Company, LLC, a subsidiary of ETP and ETE
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
Lone Star	Lone Star NGL LLC
LPG	liquefied petroleum gas

MACS	Mid-Atlantic Convenience Stores, LLC
MEP	Midcontinent Express Pipeline LLC
MGE	Missouri Gas Energy
Mi Vida JV	Mi Vida JV LLC
MMBtu	million British thermal units
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NEG	New England Gas Company
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

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

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly-owned subsidiaries based on 100% of the subsidiaries' results of operations and for unconsolidated affiliates based on the Partnership's proportionate ownership.

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PART I

ITEM 1. BUSINESS

Overview

We (Energy Transfer Partners, L.P., a Delaware limited partnership, "ETP" or the "Partnership") are one of the largest publicly traded master limited partnerships in the United States in terms of equity market capitalization (approximately $15.05 billion as of January 29, 2016). 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 owned by Energy Transfer Equity, L.P., another publicly traded master limited partnership ("ETE"). The primary activities in which we are engaged, all of which are in the United States, and the operating subsidiaries (collectively referred to as the "Operating Companies") through which we conduct those activities are as follows:

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which we refer to as ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger, CrossCountry and ET Rover Pipeline LLC. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems. ETP owns a 50% interest in MEP.
- Liquids operations, including NGL transportation, storage and fractionation services primarily through Lone Star.
- Product and crude oil operations, including the following:
  - product and crude oil transportation, terminalling services and acquisition and marketing activities through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco, Inc.

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The following chart summarizes our organizational structure as of December 31, 2015. For simplicity, certain immaterial entities and ownership interest have not been depicted.
Unless the context requires otherwise, the Partnership, the Operating Companies, and their subsidiaries are collectively referred to in this report as “we,” “us,” “ETP,” “Energy Transfer” or “the Partnership.”

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Significant Achievements in 2015 and Beyond

Strategic Transactions

Our significant strategic transactions in 2015 and beyond included the following, as discussed in more detail herein:

- ETP, as a member of a consortium, was awarded two pipeline projects for the transportation of natural gas for Mexico's state power company, CFE, under long-term contracts. The Trans-Pecos pipeline is an approximately 143-mile, 42-inch pipeline that will deliver at least 1.356 Bcf/d of natural gas from the Waha Hub to the US/Mexico border near Presidio, Texas. The Comanche Trail pipeline is an approximately 195-mile, 42-inch pipeline that will deliver at least 1.135 Bcf/d of natural gas from the Waha Hub to the US/Mexico border near San Elizario, Texas. ETP will be the construction manager and operator of both pipelines. The expected all-in cost for these two pipelines is anticipated to be approximately $1.3 billion, and we expect both pipelines to be in-service in the first quarter of 2017.
- In December 2015, ETP announced that the Lake Charles LNG Project has received approval from the FERC to site, construct and operate a natural gas liquefaction and export facility in Lake Charles, Louisiana. On February 15, 2016, Royal Dutch Shell plc completed its acquisition of BG Group plc. Final investment decisions from Royal Dutch Shell plc and LCL are expected to be made in 2016, with construction to start immediately following an affirmative investment decision and first LNG export anticipated about four years later.
- In November 2015, ETP and Sunoco LP announced ETP’s contribution to Sunoco LP of the remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP will pay ETP $2.03 billion in cash, subject to certain working capital adjustments, and will issue to ETP 5.7 million Sunoco LP common units. The transaction will be effective January 1, 2016, and is expected to close in March 2016.
- In October 2015, Sunoco Logistics completed the previously announced acquisition of a 40% membership interest (the “Bakken Membership Interest”) in Bakken Holdings Company LLC (“Bakken Holdco”). Bakken Holdco, through its wholly-owned subsidiaries, owns a 75% membership interest in each of Dakota Access, LLC and Energy Transfer Crude Oil Company, LLC, which together intend to develop the Bakken Pipeline system to deliver crude oil from the Bakken/Three Forks production area in North Dakota to the Gulf Coast. ETP transferred the Bakken Membership Interest to Sunoco Logistics in exchange for approximately 9.4 million Class B Units representing limited partner interests in Sunoco Logistics and the payment by Sunoco Logistics to ETP of $382 million of cash, which represented reimbursement for its proportionate share of the total cash contributions made in the Bakken Pipeline project as of the date of closing of the exchange transaction.
- In July 2015, in exchange for the contribution of 100% of Susser from ETP to Sunoco LP, Sunoco LP paid approximately $970 million in cash and issued to ETP subsidiaries 22 million Sunoco LP Class B units valued at approximately $970 million. The Sunoco Class B units did not receive second quarter 2015 cash distributions from Sunoco LP and converted on a one-for-one basis into Sunoco LP common units on the day immediately following the record date for Sunoco LP’s second quarter 2015 distribution. In addition, (i) a Susser subsidiary exchanged its 79,308 Sunoco LP common units for 79,308 Sunoco LP Class A units, (ii) approximately 11 million Sunoco LP subordinated units owned by Susser subsidiaries were converted into approximately 11 million Sunoco LP Class A units and (iii) Sunoco LP issued 79,308 Sunoco LP common units and approximately 11 million Sunoco LP subordinated units to subsidiaries of ETP. The Sunoco LP Class A units were contributed to Sunoco LP as part of the transaction. Sunoco LP subsequently contributed its interests in Susser to one of its subsidiaries.
- Effective July 1, 2015, ETE acquired 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, and in exchange, ETE transferred to ETP 21 million ETP common units. In connection with ETP’s 2014 acquisition of Susser, ETE agreed to provide ETP a $35 million annual IDR subsidy for 10 years, which terminated upon the closing of ETE’s acquisition of Sunoco GP. In connection with the exchange and repurchase, ETE will provide ETP a $35 million annual IDR subsidy for two years beginning with the quarter ended September 30, 2015. In connection with this transaction, the Partnership deconsolidated Sunoco LP. The Partnership continues to hold 37.8 million Sunoco LP common units accounted for under the equity method.
- On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency, with Regency surviving as a wholly-owned subsidiary of the Partnership (the “Regency Merger”). Each Regency common unit and Class F unit was converted into the right to receive 0.4124 Partnership common units. ETP issued 172.2 million ETP common units to

Regency unitholders, including 15.5 million units issued to Partnership subsidiaries. The 1.9 million outstanding Regency series A preferred units were converted into corresponding new Partnership Series A Preferred Units on a one-for-one basis.

- In March 2015, ETE transferred 30.8 million ETP common units, ETE’s 45% interest in the Bakken Pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics. In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously

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provided to ETP. These IDR subsidies, including the impact from distributions on Class I Units, were reduced by $55 million in 2015 and $30 million in 2016.

Significant Organic Growth Projects

Our significant announced organic growth projects in 2015 included the following, as discussed in more detail herein:

- As discussed in "Strategic Transactions" above, ETP and Sunoco Logistics own 60% and 40%, respectively, in Bakken Holdco, which owns 75% of each of the two joint ventures that are developing the Dakota Access Pipeline ("DAPL") and Energy Transfer Crude Oil Pipeline ("ETCOP") projects. Phillips 66 owns the remaining 25% interests and funds its proportionate share of the construction costs. The DAPL and ETCOP projects are expected to begin commercial operations in the fourth quarter of 2016.
- In July 2015, ETP, Sunoco Logistics, and Phillips 66 formed Bayou Bridge Pipeline, LLC to construct the Bayou Bridge pipeline, which will deliver crude oil from the Phillips 66 and Sunoco Logistics terminals in Nederland, Texas to refinery markets in Louisiana. Phillips 66 Partners LP, which acquired Phillips 66's interest in December 2015, holds a 40% interest in Bayou Bridge Pipeline, LLC and ETP and Sunoco Logistics each hold a 30% interest in the entity. Sunoco Logistics will be the operator of the system.
- In May 2015, ETP announced that Lone Star will construct a fourth natural gas liquids fractionation facility at Mont Belvieu, Texas. Fractionator IV, estimated to cost approximately $450 million, is scheduled to be operational by December 2016. The 120,000 barrel per day fractionator is fully subscribed by multiple long-term contracts and will provide off-take for the new 533-mile, 24- and 30-inch Lone Star Express Pipeline.
- Lone Star is currently constructing a 533 mile, 24- and 30-inch NGL pipeline from the Permian Basin to Mont Belvieu, Texas. The new pipeline, estimated to cost approximately $1.5 billion, is expected to be operational by the second quarter of 2016.
- ETP and Traverse Midstream Partners LLC own 65% and 35%, respectively, in a natural gas pipeline project (now called "Rover") to connect Marcellus and Utica shale supplies to markets in the Midwest, Great Lakes, and Gulf Coast regions of the United States and Canada. Rover has secured multiple, long-term binding shipper agreements on the project. As a result of these binding agreements, the pipeline is substantially subscribed with 15- and 20-year fee-based contracts to transport up to 3.25 Bcf/d of capacity. The pipeline is expected to be in-service to Defiance, Ohio by the second quarter of 2017 and to Dawn, Ontario by the third quarter of 2017.

Segment Overview

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

Intrastate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users, storage facilities, utilities and other pipelines. Through our intrastate transportation and storage segment, we own and operate approximately 7,500 miles of natural gas transportation pipelines with approximately 14.1 Bcf/d of transportation capacity and three natural gas storage facilities located in the state of Texas.

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

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

We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and marketing companies on our HPL System. Generally, we purchase natural gas from either the market (including purchases from our marketing operations) or from producers at the wellhead. To the extent the natural gas comes from producers, it is primarily purchased at a discount to a specified market price and typically resold to customers based on an index price. In addition, our intrastate transportation and storage segment generates revenues from fees charged for storing customers' working natural gas in our storage facilities and from managing natural gas for our own account.

Interstate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users, storage facilities, utilities and other pipelines. Through our interstate transportation and storage segment, we directly own and operate approximately 12,300 miles of interstate natural gas pipelines with approximately 11.2 Bcf per day of transportation capacity and have a 50% interest in the joint venture that owns the 185-mile Fayetteville Express pipeline and the 500 mile Midcontinent Express pipeline. ETP also owns a 50% interest in Citrus, which owns 100% of FGT, an approximately 5,325 mile pipeline system that extends from south Texas through the Gulf Coast to south Florida.

Our interstate transportation and storage segment includes Panhandle, which owns and operates a large natural gas open-access interstate pipeline network. The pipeline network, consisting of the Panhandle, Trunkline and Sea Robin transmission systems, serves customers in the Midwest, Gulf Coast and Midcontinent United States with a comprehensive array of transportation and storage services. In connection with its natural gas pipeline transmission and storage systems, Panhandle has five natural gas storage fields located in Illinois, Kansas, Louisiana, Michigan and Oklahoma. Southwest Gas operates four of these fields and Trunkline operates one.

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

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

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

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

Midstream Segment

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

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

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

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

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

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Through our midstream segment, we own and operate approximately 35,000 miles of in service natural gas, 31 natural gas processing plants, 21 natural gas treating facilities and 4 natural gas conditioning facilities with an aggregate processing, treating and conditioning capacity of approximately 10.1 Bcf/d. Our midstream segment focuses on the gathering, compression, treating, blending, and processing, and our operations are currently concentrated in major producing basins and shales, including the Austin Chalk trend and Eagle Ford Shale in South and Southeast Texas, the Permian Basin in West Texas and New Mexico, the Barnett Shale and Woodford Shale in North Texas, the Bossier Sands in East Texas, the Marcellus Shale in West Virginia and Pennsylvania, and the Haynesville Shale in East Texas 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 ELG, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in South Texas, a 33.33% membership interest in Ranch Westex JV LLC, which processes natural gas delivered from the NGLs-rich shale formations in West Texas, a 75% membership interest in ORS, which operates a natural gas gathering system in the Utica shale in Ohio, and a 50% interest in Mi Vida JV, which operates a cryogenic processing plant and related facilities in West Texas, a 51% membership interest in Aqua – PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, and a 50% interest in Sweeny Gathering LP, which operates a natural gas gathering facility in South Texas.

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

Liquids Transportation and Services Segment

Liquids transportation pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities to fractionation plants and storage facilities. NGL storage facilities are used for the storage of mixed NGLs, NGL products and petrochemical products owned by third-parties in storage tanks and underground wells, which allow for the injection and withdrawal of such products at various times of the year to meet demand cycles. NGL fractionators separate mixed NGL streams into purity products, such as ethane, propane, normal butane, isobutane and natural gasoline.

Through our liquids transportation and services segment we own Lone Star, which owns approximately 2,000 miles of NGL pipelines with an aggregate transportation capacity of approximately 388,000 Bbls/d, three NGL processing plants with an aggregate processing capacity of approximately 904 MMcf/d, four NGL and propane fractionation facilities with an aggregate capacity of 325,000 Bbls/d and NGL storage facilities with aggregate working storage capacity of approximately 51 million Bbls. Four NGL and propane fractionation facilities and the NGL storage facilities are located at Mont Belvieu, Texas, one NGL fractionation facility is located in Geismar, Louisiana, and the NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu. We also own and operate approximately 274 miles of NGL pipelines including a 50% interest in the joint venture that owns the Liberty pipeline, an approximately 87-mile NGL pipeline and the recently converted 82-mile Rio Bravo crude oil pipeline.

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

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

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

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

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Investment in Sunoco Logistics Segment

The Partnership's interests in Sunoco Logistics consist of 67.1 million Sunoco Logistics common units and 9.4 million Sunoco Logistics Class B Units, collectively representing 27.5% of the limited partner interests in Sunoco Logistics as of December 31, 2015. The Partnership also owns a 99.9% interest in Sunoco Partners LLC, the entity that owns the general partner interest and IDRs in Sunoco Logistics. Because the Partnership controls Sunoco Logistics through its ownership of the general partner, the operations of Sunoco Logistics are consolidated into the Partnership. These operations are reflected by the Partnership in the investment in Sunoco Logistics segment.

Sunoco Logistics owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets that are used to facilitate the purchase and sale of crude oil, NGLs and refined products primarily in the northeast, midwest and southwest regions of the United States. In addition, Sunoco Logistics owns interests in several product pipeline joint ventures.

Sunoco Logistics' crude oil operations provides transportation, terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest and northeastern United States. Included within the operations are approximately 5,900 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States and equity ownership interests in three crude oil pipelines. Sunoco Logistics' crude oil terminalling services operate with an aggregate storage capacity of approximately 28 million barrels, including approximately 24 million barrels at its Gulf Coast terminal in Nederland, Texas and approximately 3 million barrels at its Fort Mifflin terminal complex in Pennsylvania. Sunoco Logistics' crude oil acquisition and marketing activities utilize its pipeline and terminal assets, its proprietary fleet crude oil tractor trailers and truck unloading facilities, as well as third-party assets, to service crude oil markets principally in the mid-continent United States.

Sunoco Logistics' NGLs operations transports, stores, and executes acquisition and marketing activities utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGLs markets. The operations contain approximately 900 miles of NGLs pipelines, primarily related to its Mariner systems located in the northeast and southwest United States. Terminalling services are facilitated by approximately 5 million barrels of NGLs storage capacity, including approximately 1 million barrels of storage at its Nederland, Texas terminal facility and 3 million barrels at its Marcus Hook, Pennsylvania terminal facility (the "Marcus Hook Industrial Complex"). These operations also carry out Sunoco Logistics' NGLs blending activities, including utilizing its patented butane blending technology.

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

Retail Marketing Segment

Our retail marketing business is conducted through our wholly-owned subsidiary, Sunoco, Inc. Our retail marketing operations include the sales of motor fuel (gasoline and diesel) and merchandise at company-operated retail locations and branded convenience stores conducted in 14 states, primarily on the east coast and south regions of the United States.

We also currently own a 68.42% membership interest in Sunoco, LLC, which distributes approximately 5.3 billion gallons per year of motor fuel to customers in the east, midwest and southwest regions of the United States. The remaining 31.58% membership interest in Sunoco, LLC is held by Sunoco LP. Sunoco LP also owns 50.1% of the voting interests in Sunoco, LLC; therefore, we do not have a controlling interest in Sunoco, LLC and account for our investment under the equity method.

As discussed above, ETP expects to contribute to Sunoco LP the remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP will pay ETP $2.03 billion in cash, subject to certain working capital adjustments, and will issue to ETP 5.7 million Sunoco LP common units. The transaction will be effective January 1, 2016 and is expected to close in March 2016.

Our retail marketing segment also currently owns 37.8 million Sunoco LP common units, which we account for under the equity method. Sunoco LP is a master limited partnership that operates more than 850 convenience stores and retail fuel sites and distributes motor fuel to convenience stores, independent dealers, commercial customers and distributors located in 30 states at

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approximately 6,800 sites, both directly as well as through its 31.58% interest in Sunoco, LLC. Sunoco LP's general partner is owned by ETE.

All Other Segment

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

- Prior to the Regency Merger, we owned an investment in Regency common and Class F units, which were received by Southern Union (now Panhandle) in exchange for the contribution of its interest in Southern Union Gathering Company, LLC to Regency on April 30, 2013.
- Sunoco, Inc. owns an approximate 33% non-operating interest in PES, a refining joint venture with The Carlyle Group, L.P. ("The Carlyle Group"), which owns a refinery in Philadelphia. Sunoco, Inc. has a supply contract for gasoline and diesel produced at the refinery for its retail marketing business.
- We conduct marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices of natural gas, less the costs of transportation. For the off-system gas, we purchase gas or act as an agent for small independent producers that may not have marketing operations.
- We own all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.
- We own 100% of the membership interests of Energy Transfer Group, L.L.C. ("ETG"), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including our other segments.
- We own a 40% interest in LCL, which is developing a LNG liquefaction project, as described further under "Asset Overview – All Other" below.
- We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.
- We are involved in the management of coal and natural resources properties and the related collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. These operations also included Coal Handling, which owns and operates end-user coal handling facilities.
- ETP also owns PEI Power Corp. and PEI Power II, which own and operate a facility in Pennsylvania that generates a total of 75 megawatts of electrical power.

Asset Overview

Intrastate Transportation and Storage

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

ET Fuel System

- Capacity of 5.2 Bcf/d
- Approximately 2,770 miles of natural gas pipeline
- Two storage facilities with 12.4 Bcf of total working gas capacity
- Bi-directional capabilities

The ET Fuel System serves some of the most prolific production areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. The ET Fuel System has many interconnections with pipelines providing direct access to power plants, other intrastate and interstate pipelines, and is strategically located near high-growth production areas and provides access to the Waha Hub near Midland, Texas, the Katy Hub near Houston, Texas and the Carthage Hub in East Texas, the three major natural gas trading centers in Texas.

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The ET Fuel System also includes our Bethel natural gas storage facility, with a working capacity of 6.4 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. All of our storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 2017.

In addition, the ET Fuel System is integrated with 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.

Oasis Pipeline

- Capacity of 1.2 Bcf/d
- Approximately 600 miles of natural gas pipeline
- Connects Waha to Katy market hubs
- Bi-directional capabilities

The Oasis pipeline is primarily a 36-inch natural gas pipeline. It has bi-directional capability with approximately 1.2 Bcf/d of throughput capacity moving west-to-east and greater than 750 MMcf/d of throughput capacity moving east-to-west. The Oasis pipeline has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

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

HPL System

- Capacity of 5.3 Bcf/d
- Approximately 3,800 miles of natural gas pipeline
- Bammel storage facility with 52.5 Bcf of total working gas capacity

The HPL System is an extensive network of intrastate natural gas pipelines, an underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from South Texas, the Gulf Coast of Texas, East Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The HPL System is well situated to gather and transport gas in many of the major gas producing areas in Texas including a strong presence in the key Houston Ship Channel and Katy Hub markets, allowing us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel and Agua Dulce, and 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, 2015, we had approximately 9.3 Bcf committed under fee-based arrangements with third parties and approximately 40 Bcf stored in the facility for our own account.

East Texas Pipeline

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

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

System.

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RIGS Haynesville Partnership Co.

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

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

Interstate Transportation and Storage

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

Florida Gas Transmission Pipeline

- Capacity of 3.1 Bcf/d
- Approximately 5,325 miles of interstate natural gas pipeline
- FGT is owned by Citrus, a 50/50 joint venture with Kinder Morgan, Inc. ("KMI")

The Florida Gas Transmission pipeline is an open-access interstate pipeline system with a mainline capacity of 3.1 Bcf/d and approximately 5,325 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The Florida Gas Transmission pipeline system receives natural gas from various onshore and offshore natural gas producing basins. FGT is the principal transporter of natural gas to the Florida energy market, delivering over 66% of the natural gas consumed in the state. In addition, Florida Gas Transmission's pipeline system operates and maintains over 81 interconnects with major interstate and intrastate natural gas pipelines, which provide FGT's customers access to diverse natural gas producing regions.

FGT's customers include electric utilities, independent power producers, industrials and local distribution companies.

Transwestern Pipeline

- Capacity of 2.1 Bcf/d
- Approximately 2,600 miles of interstate natural gas pipeline
- Bi-directional capabilities

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

Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users.

Panhandle Eastern Pipe Line

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

The Panhandle Eastern Pipe Line's transmission system consists of four large diameter pipelines extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan. Panhandle Eastern Pipe Line is owned by a subsidiary of ETP Holdco.

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Trunkline Gas Company

- Capacity of 0.9 Bcf/d
- Approximately 2,000 miles of interstate natural gas pipeline
- Bi-directional capabilities

The Trunkline Gas pipeline's transmission system consists of one large diameter pipeline extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and to Michigan. Trunkline Gas pipeline is owned by a subsidiary of ETP Holdco.

During 2015, 45 miles of Trunkline 24-inch pipeline and 636 miles of Trunkline 30-inch pipeline were taken out of service in advance of being repurposed from natural gas service to crude oil service, coinciding with the transfer of the assets to a related company.

Tiger Pipeline

- Capacity of 2.4 Bcf/d
- Approximately 195 miles of interstate natural gas pipeline
- Bi-directional capabilities

The Tiger pipeline is an approximately 195-mile interstate natural gas pipeline that connects to our dual 42-inch pipeline system near Carthage, Texas, extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana. The pipeline has a capacity of 2.4 Bcf/d, all of which is sold under long-term contracts ranging from 10 to 15 years.

Fayetteville Express Pipeline

- Capacity of 2.0 Bcf/d
- Approximately 185 miles of interstate natural gas pipeline
- 50/50 joint venture through ETC FEP with KMI

The Fayetteville Express pipeline is an approximately 185-mile interstate natural gas pipeline that originates near Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline Gas Company in Panola County, Mississippi. The pipeline has long-term contracts for 1.85 Bcf/d ranging from 10 to 12 years.

Sea Robin Pipeline

- Capacity of 2.0 Bcf/d
- Approximately 1,000 miles of interstate natural gas pipeline

The Sea Robin pipeline's transmission system consists of two offshore Louisiana natural gas supply systems extending approximately 120 miles into the Gulf of Mexico.

Midcontinent Express Pipeline LLC

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

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

Gulf States

- Capacity of 0.1 Bcf/d
- Approximately 10 miles of interstate natural gas pipeline

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

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Midstream

The following details our assets in the midstream segment.

Southeast Texas System

- Approximately 7,100 miles of natural gas pipeline
- One natural gas processing plant (La Grange) with aggregate capacity of 210 MMcf/d
- 10 natural gas treating facilities with aggregate capacity of 1.2 Bcf/d
- One natural gas conditioning facility with aggregate capacity of 200 MMcf/d

The Southeast Texas System is an integrated system that gathers, compresses, treats, processes and transports natural gas from the Austin Chalk trend. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. This system is connected to the Katy Hub through the East Texas pipeline and is connected to the Oasis pipeline, as well as two power plants. This allows us to bypass our processing plants and treating facilities when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with natural gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

The La Grange processing plant is a natural gas processing plant that processes the rich natural gas that flows through our system to produce residue gas and NGLs. Residue gas is delivered into our intrastate pipelines and NGLs are delivered into our NGL pipelines and then 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. In addition, our conditioning facilities remove heavy hydrocarbons from the gas gathered into our systems so the gas can be redelivered and meet downstream pipeline hydrocarbon dew point specifications.

North Texas System

- Approximately 160 miles of natural gas pipeline
- One natural gas processing plant (the Godley plant) with aggregate capacity of 700 MMcf/d
- One natural gas conditioning facility with capacity of 100 MMcf/d

The North Texas System is an integrated system located in four counties in North Texas that gathers, compresses, treats, processes and transports natural gas from the Barnett and Woodford Shales. The system includes our Godley processing plant, which processes rich natural gas produced from the Barnett Shale and is integrated with the North Texas System and the ET Fuel System. The facility consists of a processing plant and a conditioning facility.

Northern Louisiana

- Approximately 280 miles of natural gas pipeline
- Three natural gas treating facilities with aggregate capacity of 385 MMcf/d

Our Northern Louisiana assets comprise 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.

Eagle Ford System

- Approximately 1,090 miles of natural gas pipeline
- Four processing plants (Chisholm, Kenedy, Jackson and King Ranch) with capacity of 1,940 MMcf/d
- One natural gas treating facility with capacity of 300 MMcf/d

The Eagle Ford gathering system consists of 30-inch and 42-inch natural gas transportation pipelines delivering 1.4 Bcf/d of capacity originating in Dimmitt County, Texas and extending to our Chisholm pipeline for ultimate deliveries to our existing processing plants. Our Chisholm, Kenedy and Jackson 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.

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Arklatex System

- Approximately 2,800 miles of natural gas pipeline
- Three natural gas processing facilities (Dubach, Dubberly and Brookeland) with aggregate capacity of 510 MMcf/d
- Two natural gas treating facilities
- One conditioning facility

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

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

South Texas System

- Approximately 1,300 miles of natural gas pipeline
- Three natural gas treating facilities with aggregate capacity of 335 MMcf/d

The South Texas assets gather, compress, treat and dehydrate natural gas in Bee, LaSalle, Webb, Karnes, Atascosa, McMullen, Frio and Dimmitt counties. The pipeline systems are connected to third-party processing plants and treating facilities that include acid gas reinjection wells located in McMullen County, Texas. We also gather oil for producers in the region and deliver it to tanks for further transportation by truck or pipeline.

The natural gas supply for the south Texas gathering systems is derived from a combination of natural gas wells located in a mature basin that generally have long lives and predictable gas flow rates, including the Frio, Vicksburg, Miocene, Canyon Sands and Wilcox formations, and the NGLs-rich and oil-rich Eagle Ford shale formation.

We own a 60% interest in ELG with Talisman Energy USA Inc. and Statoil Texas Onshore Properties LP owning the remaining 40% interest. We operate a natural gas gathering oil pipeline and oil stabilization facilities for the joint venture while our joint venture partners operate a lean gas gathering system in the Edwards Lime natural gas trend that delivers to this system.

Permian System

- Approximately 7,820 miles of natural gas pipeline
- 8 processing facilities (Waha, Coyanosa, Red Bluff, Halley, Jal, Keyston, Tippet and Rebel) with aggregate capacity of 995 MMcf/d
- Two treating facilities with aggregate capacity of 200 MMcf/d

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

During 2015, Regency completed construction on a 200 MMcf/d cryogenic processing plant on behalf of Mi Vida JV, a joint venture in which we own a 50% membership interest. We operate the plant and related facilities on behalf of Mi Vida JV.

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

Mid-Continent Region

- Approximately 13,500 miles of natural gas pipeline
- 15 natural gas processing facilities (Mocane, Beaver, Antelope Hills, Woodall, Wheeler, Sunray, Hemphill, Phoenix, Crescent, Hamlin, Spearman, Red Deer, Lefors, Cargray and Gray) with aggregate capacity of 910 MMcf/d
- One natural gas treating facilities with aggregate capacity of 20 MMcf/d

The mid-continent systems are located in two large natural gas producing regions in the United States, the Hugoton Basin in southwest Kansas, and the Anadarko Basin in western Oklahoma and the Texas Panhandle. These mature basins have continued to provide generally long-lived, predictable production volume. Our mid-continent gathering assets are extensive systems that

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gather, compress and dehydrate low-pressure gas. We have 15 natural gas producing facilities and approximately 13,500 miles of gathering pipeline.

We operate our mid-continent gathering systems at low pressures to maximize the total throughput volumes from the connected wells. Wellhead pressures are therefore adequate to allow for flow of natural gas into the gathering lines without the cost of wellhead compression.

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

- Approximately 500 miles of natural gas pipeline

The eastern region assets are located in Pennsylvania, Ohio, and West Virginia, and gather natural gas from the Marcellus and Utica basins. Our eastern gathering assets include approximately 500 miles of natural gas gathering pipeline, natural gas trunkline pipelines, and fresh water pipelines, and the Lycoming, Wyoming, East Lycoming, Bradford, Green County, and Preston gathering and processing systems.

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

We and Traverse ORS LLC, a subsidiary of Traverse Midstream Partners LLC, own a 75% and 25% membership interest, respectively, in the ORS joint venture. On behalf of ORS, we constructed and are operating its Ohio Utica River System, (the “ORS System”) which was completed in 2015 and consists of a 52-mile, 36-inch gathering trunkline that will be capable of delivering up to 2.1 Bcf/d to Rockies Express Pipeline (“REX”) and Texas Eastern Transmission, and potentially others and the construction of 25,000 horsepower of compression at the REX interconnect. This project also included the construction of a 12-mile, 30-inch lateral that connected to the tailgate of the Cadiz processing plant and Harrison County wellhead production.

Other Midstream Assets

The midstream segment also includes our interests in various midstream assets located in Texas, New Mexico and Louisiana, with approximately 60 miles of gathering pipelines aggregating a combined capacity of approximately 115 MMcf/d, as well as one conditioning facility and our Rebel processing plant with capacity of 180 MMcf/d. We also own approximately 27 miles of gathering pipelines serving the Marcellus Shale in West Virginia with aggregate capacity of approximately 250 MMcf/d.

Liquids Transportation and Services

The following details our assets in the liquids transportation and services segment. Certain assets, as discussed below, are owned by Lone Star in which we have a 100% interest.

West Texas System

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

The West Texas System, owned by Lone Star, is an intrastate NGL pipeline consisting of 3-inch to 16-inch long-haul, mixed NGLs transportation pipeline that delivers 137,000 Bbls/d of capacity from processing plants in the Permian Basin and Barnett Shale to the Mont Belvieu NGL storage facility.

West Texas Gateway Pipeline

- Capacity of 209,000 Bbls/d
- Approximately 570 miles of NGL transmission pipeline

The West Texas Gateway Pipeline, owned by Lone Star, began service in December 2012 and transports NGLs produced in the Permian and Delaware Basins and the Eagle Ford Shale to Mont Belvieu, Texas.

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

Other NGL pipelines include the 127-mile Justice pipeline with capacity of 340,000 Bbls/d, the 87-mile Liberty pipeline with a capacity of 90,000 Bbls/d, the 45-mile Freedom pipeline with a capacity of 40,000 Bbls/d and the 15-mile Spirit pipeline with a capacity of 20,000 Bbls/d.

Rio Bravo Pipeline
- Aggregate capacity of 100,000 Bbls/d
- Approximately 82 miles of crude oil transmission pipeline

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

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

The Mont Belvieu storage facility, owned by Lone Star, is an integrated liquids storage facility with over 48 million Bbls of salt dome capacity providing 100% fee-based cash flows. The Mont Belvieu storage facility has access to multiple NGL and refined product pipelines, the Houston Ship Channel trading hub, and numerous chemical plants, refineries and fractionators.

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

Hattiesburg Storage Facility
- Working storage capacity of approximately 3.0 million Bbls

The Hattiesburg storage facility, owned by Lone Star, is an integrated liquids storage facility with approximately 3.0 million Bbls of salt dome capacity, providing 100% fee-based cash flows.

Sea Robin Processing Plant
- One processing plant with 850 MMcf/d residue capacity and 26,000 Bbls/d NGL capacity
- 20% non-operating interest held by Lone Star

Sea Robin is a rich gas processing plant located on the Sea Robin Pipeline in southern Louisiana. The plant, which is connected to nine interstate and four intrastate residue pipelines as well as various deep-water production fields, has a residue capacity of 850 MMcf/d and an NGL capacity of 26,000 Bbls/d.

Refinery Services
- One processing plant (Chalmette) with capacity of 54 MMcf/d
- One NGL fractionator with 25,000 Bbls/d capacity
- Approximately 100 miles of NGL pipelines

Refinery Services, owned by Lone Star, consists of a refinery off-gas processing and O-grade NGL fractionation complex located along the Mississippi River refinery corridor in southern Louisiana that cryogenically processes refinery off-gas and fractionates the O-grade NGL stream into its higher value components. The O-grade fractionator located in Geismar, Louisiana is connected by approximately 100 miles of pipeline to the Chalmette processing plant.

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Investment in Sunoco Logistics

The following details our assets in the investment in Sunoco Logistics segment.

Crude Oil

Sunoco Logistics' crude oil consists of an integrate set of pipeline, terminalling and acquisition and marketing assets that service the movement of crude oil from producers to end-user markets.

Crude Oil Pipelines

Southwest United States Pipelines. The Southwest pipelines include crude oil trunk pipelines and crude oil gathering pipelines in Texas. This includes the Permian Express 2 pipeline project which provides takeaway capacity from the Permian Basin, with origins in multiple locations in Western Texas: Midland, Garden City and Colorado City. With an initial capacity of approximately 200,000 Bbls/d, Permian Express 2 began delivery to multiple refiners and markets in the third quarter 2015. In connection with this project, Sunoco Logistics entered into an agreement with Vitol, Inc. to form SunVit, with each party owning a 50% interest. SunVit originates in Midland, Texas and runs to Garden City, Texas, where it connects into the Permian Express 2 pipeline system. The SunVit pipeline also commenced operations in the third quarter 2015.

The Southwest pipelines also include a crude oil pipeline and gathering systems in Oklahoma. Sunoco Logistics has the ability to deliver substantially all of the crude oil gathered on the Oklahoma system to Cushing and is one of the largest purchasers of crude oil from producers in the state.

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

Sunoco Logistics also owns a crude oil pipeline that runs from Marysville, Michigan to Toledo, Ohio, and a truck injection point for local production at Marysville. This pipeline receives crude oil from the Enbridge pipeline system for delivery to refineries located in Toledo, Ohio and to Marathon Petroleum Corporation's Samaria, Michigan tank farm, which supplies its refinery in Detroit, Michigan.

Crude Oil Terminals

Nederland. The Nederland terminal, located on the Sabine-Neches waterway between Beaumont and Port Arthur, Texas, is a large marine terminal providing storage and distribution services for refiners and other large transporters of crude oil and NGLs. The terminal receives, stores, and distributes crude oil, NGLs, feedstocks, lubricants, petrochemicals, and bunker oils (used for fueling ships and other marine vessels), and also blends lubricants. The terminal currently has a total storage capacity of approximately 25 million barrels in approximately 130 above ground storage tanks with individual capacities of up to 660,000 barrels, of which 24 million barrels of storage are dedicated to crude oil.

The Nederland terminal can receive crude oil at each of its five ship docks and three barge berths. The five ship docks are capable of receiving over 2 million Bbls/d of crude oil. In addition to Sunoco Logistics' crude oil pipelines, the terminal can also receive crude oil through a number of other pipelines, including the DOE. The DOE pipelines connect the terminal to the United States Strategic Petroleum Reserve's West Hackberry caverns at Hackberry, Louisiana and Big Hill near Winnie, Texas, which have an aggregate storage capacity of approximately 375 million barrels. The Nederland Terminal can deliver crude oil and other petroleum products via pipeline, barge, ship, rail, or truck. In total, the terminal is capable of delivering over 2 million Bbls/d of crude oil to Sunoco Logistics' crude oil pipelines or a number of third party pipelines including the DOE. The Nederland terminal generates crude oil revenues primarily by providing term or spot storage services and throughput capabilities to a number of customers.

Fort Mifflin. The Fort Mifflin terminal complex is located on the Delaware River in Philadelphia, Pennsylvania and includes the Fort Mifflin terminal, the Hog Island wharf, the Darby Creek tank farm and connecting pipelines. Revenues are generated from the Fort Mifflin terminal complex by charging fees based on throughput. The Fort Mifflin terminal contains two ship docks with freshwater drafts and a total storage capacity of approximately 570,000 barrels. Crude oil and some refined products enter the Fort Mifflin terminal primarily from marine vessels on the Delaware River. One Fort Mifflin dock is designed to handle crude oil from very large crude carrier-class 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.

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

Eagle Point. The Eagle Point terminal is located in Westville, New Jersey and consists of docks, truck loading facilities and a tank farm. The docks are located on the Delaware River and can accommodate three marine vessels (ships or barges) to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges. The tank farm has a total active storage capacity of approximately 1 million barrels and can receive crude oil via barge, pipeline and rail. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage.

Crude Oil Acquisition and Marketing

Sunoco Logistics' crude oil acquisition and marketing activities include the gathering, purchasing, marketing and selling of crude oil primarily in the mid-continent United States. The operations are conducted using Sunoco Logistics' assets, which include approximately 375 crude oil transport trucks and approximately 140 crude oil truck unloading facilities, as well as third-party truck, rail and marine assets. Specifically, the crude oil acquisition and marketing activities include:

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

Natural Gas Liquids

Sunoco Logistics' Natural Gas Liquids consists of an integrate set of pipeline, terminalling and acquisition and marketing assets that service the movement of NGLs from producers to end-user markets.

NGL Pipelines

- Sunoco Logistics owns approximately 900 miles of NGLs pipelines, primarily related to the Mariner systems in the northeast and southwest United States. The Mariner South pipeline is part of a joint project with Lone Star to deliver export-grade propane and butane products from Lone Star's Mont Belvieu, Texas storage and fractionation complex to our marine terminal in Nederland, Texas. The pipeline has a capacity of approximately 200,000 Bbls/d and can be scaled depending on shipper interest.
- The Mariner West pipeline provides transportation of ethane products from the Marcellus shale processing and fractionating areas in Houston, Texas, Pennsylvania to Marysville, Michigan and the Canadian border. Mariner West commenced operations in the fourth quarter 2013, with capacity to transport approximately 50,000 Bbls/d of ethane.
- The Mariner East pipeline transports NGLs from the Marcellus and Utica Shales areas in Western Pennsylvania, West Virginia and Eastern Ohio to destinations in Pennsylvania, including our Marcus Hook Industrial Complex on the Delaware River, where they are processed, stored and distributed to local, domestic and waterborne markets. The first phase of the project, referred to as Mariner East 1, consisted of interstate and intrastate propane and ethane service and commenced operations in the fourth quarter of 2014 and the first quarter of 2016, respectively. The second phase of the project, referred to as Mariner East 2, will expand the total takeaway capacity to 345,000 Bbls/d for interstate and intrastate propane, ethane and butane service, and is expected to commence operations in the first half of 2017.

NGLs Terminals

Marcus Hook Industrial Complex. In 2013, Sunoco Logistics acquired Sunoco, Inc.'s Marcus Hook Industrial Complex. The acquisition included terminalling and storage assets, with a capacity of approximately 3 million barrels of NGL storage capacity in underground caverns, and related commercial agreements. The facility can receive NGLs via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck. In addition to providing NGLs storage and terminalling services to both affiliates and third party customers, the Marcus Hook Industrial Complex currently serves as an off-take outlet for the Mariner East 1 pipeline, and will provide similar off-take capabilities for the Mariner East 2 pipeline when it commences operations.

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Inkster. The Inkster terminal, located near Detroit, Michigan, contains eight salt caverns with a total storage capacity of approximately one million barrels of NGLs. Sunoco Logistics uses 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.

NGLs Acquisition & Marketing

Sunoco Logistics' NGLs acquisition and marketing activities include the acquisition, blending and marketing of such products at Sunoco Logistics' various terminals and third-party facilities.

Refined Products

Sunoco Logistics' refined products consists of an integrate set of pipeline, terminalling and acquisition and marketing assets that service the movement of refined products from producers to end-user markets.

Refined Products Pipelines

Sunoco Logistics owns and operates approximately 1,800 miles of refined products pipelines in several regions of the United States. The pipelines primarily provide transportation in the northeast, midwest, and southwest United States. These pipelines include Sunoco Logistics' controlling financial interest in Inland Corporation ("Inland").

The mix of products delivered varies seasonally, with gasoline demand peaking during the summer months, and demand for heating oil and other distillate fuels peaking in the winter. In addition, weather conditions in the areas served by the refined products pipelines affect both the demand for, and the mix of, the refined products delivered through the pipelines, although historically, any overall impact on the total volume shipped has been short-term. The products transported in these pipelines include multiple grades of gasoline, and middle distillates, such as heating oil, diesel and jet fuel.

In addition to the consolidated pipeline assets, Sunoco Logistics owns equity interests in four common carrier refined products pipelines including: Explorer Pipeline Company, Yellowstone Pipe Line Company, West Shore Pipe Line Company and Wolverine Pipe Line Company.

Refined Products Terminals

Refined Products. Sunoco Logistics has approximately 40 refined products terminals with an aggregate storage capacity of 8 million barrels that facilitate the movement of refined products to or from storage or transportation systems, such as a pipeline, to other transportation systems, such as trucks or other pipelines. Each facility typically consists of multiple storage tanks and is equipped with automated truck loading equipment that is operational 24 hours a day.

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

Marcus Hook Industrial Complex. The Marcus Hook Industrial Complex can receive refined products via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck.

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

Refined Products Acquisition and Marketing

Sunoco Logistics' refined products acquisition and marketing activities include the acquisition, marketing and selling of bulk refined products such as gasoline products and distillates. These activities utilize Sunoco Logistics' refined products pipeline and terminal assets, as well as third-party assets and facilities.

Retail Marketing

As discussed above, the Partnership expects to contribute all of its remaining retail operations to Sunoco LP in early March 2016.

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Company-operated sites, which are operated by Sunoco R&M, are sites at which fuel products are delivered directly to the site by company-operated trucks or by contract carriers. Most of the company-operated sites include a convenience store under the Aplus® brand. The highest concentration of retail outlets are located in Pennsylvania, New York, Florida, New Jersey, and South Carolina.

Brands

We manage a strong proprietary fuel and convenience store brand through our retail portfolio of outlets, including Sunoco® and Aplus®.

Of the total retail outlets that are company-operated, 438 operate under the Sunoco® fuel brand as of December 31, 2015. The Sunoco® brand is positioned as a premium fuel brand. Brand improvements in recent years have focused on physical image, customer service and product offerings. In addition, Sunoco, Inc. believes its brands and high performance gasoline business have benefited from its sponsorship agreements with NASCAR®, INDYCAR® and the NHRA®. Under the sponsorship agreement with NASCAR®, which continues until 2022, Sunoco® is the Official Fuel of NASCAR® and APlus® is the Official Convenience Store of NASCAR®. Sunoco, Inc. has exclusive rights to use certain NASCAR® trademarks to advertise and promote Sunoco, Inc. products and is the exclusive fuel supplier for the three major NASCAR® racing series. The sponsorship agreements with INDYCAR® and NHRA® continue through 2018 and 2024, respectively.

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

Convenience Store Operations

Our subsidiaries operate 384 convenience stores under our proprietary Aplus® convenience store brand as of December 31, 2015. These stores complement sales of fuel products with a broad mix of merchandise, food service, and other services.

The following table sets forth information concerning the company-operated convenience stores during 2015:

Number of stores at December 31, 2015	384	
Merchandise sales (thousands of dollars/store/month)	$119	
Merchandise margin (% sales)	26.5	%

All Other

Liquefaction Project

LCL, an entity owned 60% by ETE and 40% by ETP, is in the process of developing the liquefaction project in conjunction with BG pursuant to a project development agreement entered into in September 2013. Pursuant to this agreement, each of LCL and BG are obligated to pay 50% of the development expenses for the liquefaction project, subject to reimbursement by the other party if such party withdraws from the project prior to both parties making an affirmative FID to become irrevocably obligated to fully develop the project, subject to certain exceptions. The liquefaction project is expected to consist of three LNG trains with a combined design nameplate outlet capacity of 16.2 metric tonnes per annum. Once completed, the liquefaction project will enable LCL to liquefy domestically produced natural gas and export it as LNG. By adding the new liquefaction facility and integrating with the existing LNG regasification/import facility, the enhanced facility will become a bi-directional facility capable of exporting and importing LNG. BG is the sole customer for the existing regasification facility and is obligated to pay reservation fees for 100% of the regasification capacity regardless of whether it actually utilizes such capacity pursuant to a regasification services agreement that terminates in 2030. The liquefaction project will be constructed on 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 construction of the liquefaction project is subject to each of LCL and BG making an affirmative FID to proceed with the project, which decision is in the sole discretion of each party. In the event an affirmative FID is made by both parties, LCL and BG will enter into several agreements related to the project, including a liquefaction services agreement pursuant to which BG will pay LCL for liquefaction services on a tolling basis for a minimum 25-year term with evergreen extension options for 20 years. In addition, a subsidiary of BG, a highly experienced owner and operator of LNG facilities, would oversee construction of the liquefaction facility and, upon completion of construction, manage the operations of the liquefaction facility on behalf of LCL. Subject to receipt of regulatory approvals, we anticipate that each of LCL and BG will make an affirmative FID in 2016 and then commence construction of the liquefaction project in order to place the first and second LNG trains in service in 2021 and the third train in service in early 2022.

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

Prior to being authorized to export LNG, we must also receive wetlands permits from the U.S. Army Corps of Engineers (“USACE”) to perform wetlands mitigation work and to perform modification and dredging work for the temporary and permanent dock facilities at the Lake Charles LNG facilities. We expect to receive the wetlands permit from the USACE in the first quarter of 2016.

In December 2015, ETP announced that the Lake Charles LNG Project has received approval from the FERC to site, construct and operate a natural gas liquefaction and export facility in Lake Charles, Louisiana. On February 15, 2016, Royal Dutch Shell plc completed its acquisition of BG Group plc. Final investment decisions from Royal Dutch Shell plc and LCL are expected to be made in 2016, with construction to start immediately following an affirmative investment decision and first LNG export anticipated about four years later.

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.

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, 2015, we owned or controlled approximately 821 million tons of proven and probable coal reserves in central and northern Appalachia, properties in eastern Kentucky, Tennessee, southwestern Virginia and southern West Virginia, and the Illinois Basin, properties in southern Illinois, Indiana, and western Kentucky and as the operator of end-user coal handling facilities. Since 2004, the Natural Resources segment held a 50% interest in a coal services company with Alpha Natural Resources. In December 2014, we acquired the remaining 50% membership interest. The company, now known as Materials Handling Solutions, LLC, owns and operates facilities for industrial customers on a fee basis. During 2014, our coal reserves located in the San Juan basin were depleted and our associated coal royalties revenues ceased.

Business Strategy

We have designed our business strategy with the goal of creating and maximizing value to our Unitholders. 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 master limited partnership with a focus on increasing the amount of cash available for distribution on each Common Unit. 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.

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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 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 companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.

NGL

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

Crude Oil and Products

In markets served by our products and crude oil pipelines, we face competition from other pipelines. Generally, pipelines are the 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 trucks that deliver products in a number of areas that our pipeline operations serve. While their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for incremental and marginal volume in many areas served by our pipelines.

We also face competition among common carrier pipelines carrying crude oil. This competition is based primarily on transportation charges, access to crude oil supply and market demand. Similar to pipelines carrying products, the high capital costs deter competitors for the crude oil pipeline systems from building new pipelines. Competitive factors in crude oil purchasing and marketing include price and contract flexibility, quantity and quality of services, and accessibility to end markets.

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

Retail Marketing

We face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations of large integrated oil companies, independent gasoline service stations, convenience stores, fast food stores, and other similar retail outlets, some of which are well-recognized national or regional retail systems. The number of competitors varies depending on the geographical area. It also varies with gasoline and convenience store offerings. The principal competitive factors affecting our retail marketing operations include gasoline and diesel acquisition costs, site location, product price, selection and quality,

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site appearance and cleanliness, hours of operation, store safety, customer loyalty and brand recognition. We compete by pricing gasoline competitively, combining retail gasoline business with convenience stores that provide a wide variety of products, and using advertising and promotional campaigns. We believe that we are in a position to compete effectively as a marketer of refined products because of the location of our retail network, which is well integrated with the distribution system operated by Sunoco Logistics.

Credit Risk and Customers

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

The Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, 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 in recent months for crude oil. As a result, some of our exploration and production customers have been negatively impacted; however, we are monitoring these customers and mitigating credit risk as necessary.

During the year ended December 31, 2015, none of our customers individually accounted for more than 10% of our consolidated revenues.

Regulation of Interstate Natural Gas Pipelines. The FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the Natural Gas Act ("NGA"), the FERC generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, "transportation" includes natural gas pipeline transmission (forwardhauls and backhauls), storage and other services. The Florida Gas Transmission, Transwestern, Panhandle Eastern, Trunkline Gas, Tiger, Fayetteville Express, 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 storage facilities that are subject to the FERC's regulatory oversight.

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

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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.

In 2011, in lieu of filing a new NGA Section 4 general rate case, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. In general, the settlement provides for the continued use of Transwestern's currently effective transportation and fuel tariff rates, with the exception of certain San Juan Lateral fuel rates, which we were required to reduce over a three year period beginning in April 2012. On October 1, 2014, Transwestern filed a general NGA Section 4 rate case pursuant to a 2011 settlement agreement with its shippers. On December 2, 2014, the FERC issued an order accepting and suspending the rates to be effective April 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in August 2015. Transwestern reached a settlement with its customers, and filed a settlement on June 22, 2015. The settlement also resolved certain non-rate matters, and approved Transwestern's use of certain previously approved accounting methodologies. The FERC approved the settlement by order dated October 15, 2015.

On October 31, 2014, FGT filed a general NGA Section 4 rate case pursuant to a 2010 settlement agreement with its shippers. On November 28, 2014, the FERC issued an order accepting and suspending the rates to be effective May 1, 2015, subject to refund, and setting a procedural schedule with a hearing scheduled in late 2015. FGT reached a settlement with its customers, and filed a settlement on September 11, 2015. The FERC approved the settlement by order dated December 4, 2015.

On December 2, 2013, Sea Robin filed a general NGA Section 4 rate case at the FERC as required by a previous rate case settlement. In the filing, Sea Robin sought to increase its authorized rates to recover costs related to asset retirement obligations, depreciation, and return and taxes. Filed rates were put into effect June 1, 2014 and estimated settlement rates were put into effect September 1, 2014, subject to refund. A settlement was reached with the shippers and a stipulation and agreement was filed with the FERC on July 23, 2014. The settlement was certified to the FERC by the administrative law judge on October 7, 2014 and the settlement, as modified on January 16, 2015, was approved by the FERC on June 26, 2015. In September 2015, related to the final settlement, Sea Robin made refunds to customers totaling $11 million, including interest.

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

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

Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (i) to defraud using any device, scheme or artifice; (ii) to make any untrue statement of material fact or omit a material fact; or (iii) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("CEA"). With regard to our physical purchases and sales of natural gas, NGLs or other energy commodities; our gathering or transportation of these energy commodities; and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess or seek civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

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

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

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

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

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

To the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to 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 gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and varying interpretations, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by the FERC, the courts and Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana's Pipeline Operations Section of the

Department of Natural Resources' Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities.

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

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

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

Regulation of Interstate Crude Oil and Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the 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 tariffs charged by us ultimately will be upheld if challenged, management believes that the tariffs now in effect for our pipelines are within the maximum rates allowed under current FERC 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.

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

Regulation of Pipeline Safety. Our pipeline operations are subject to regulation by the DOT, through the PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (“NGPSA”), with respect to natural gas and the

Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 ("PSI Act") and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES Act"). The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas ("HCAs"), which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Failure to comply with the 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, or the issuance of injunctions limiting or prohibiting some or all of our operations in the affected area.

The NGPSA and HLPSA were most recently amended in 2012 when President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), which re-authorized the federal pipeline safety programs of PHMSA through 2015 and increased pipeline safety regulation. Among other things, the legislation 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; permitted the DOT Secretary to mandate automatic or remote controlled shut off valves on new or entirely replaced pipelines; required the DOT Secretary to evaluate whether integrity management system requirements should be expanded beyond HCAs; and provided for regulation of carbon dioxide transported by pipeline in a gaseous state and required the DOT Secretary to prescribe minimum safety regulations for such transportation. New pipeline safety legislation that would reauthorize the federal pipeline safety programs of PHMSA through 2019 has been introduced and is expected to be considered by Congress in 2016. One bill entitled "Securing America's Future Energy: Protecting Infrastructure of Pipelines and Enhancing Safety" (or "SAFE PIPES") has already been approved by the Senate Committee on Commerce, Science, and Transportation and is now subject to consideration by the U.S. Senate. Passage of any new legislation reauthorizing the PHMSA pipeline safety programs is expected to require, among other things, pursuit of some or all of those legal mandates included in the 2011 Pipeline Safety Act but not acted upon by the DOT Secretary or PHMSA.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. The states in which we conduct operations typically have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. Under such state regulatory programs, states have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, PHMSA and individual states may pass or implement additional safety requirements that could result in increased compliance costs for us and other companies in our industry. For example, federal construction, maintenance and inspection standards under the NGPSA that apply to pipelines in relatively populated areas may not apply to gathering lines running through rural regions. This "rural gathering exemption" under the NGPSA presently exempts substantial portions of our gathering facilities located outside of cities, towns or any area designated as residential or commercial from jurisdiction under the NGPSA, but does not apply to our intrastate natural gas pipelines. In recent years, the PHMSA has considered changes to this rural gathering exemption, including publishing an advance notice of proposed rulemaking relating to gas pipelines in 2011, in which the agency sought public comment on possible changes to the definition of "high consequence areas" and "gathering lines" and the strengthening of pipeline integrity management requirements. More recently, in October 2015, PHMSA issued a notice of proposed rulemaking relating to hazardous liquid pipelines that, among other things, proposes to extend its integrity management requirements to previously exempt pipelines, and to impose additional obligations on pipeline operators that are already subject to the integrity management requirements. Specifically, PHMSA proposes to extend reporting requirements to all gravity and gathering lines, require periodic inline integrity assessments of pipelines that are located outside of HCAs, and require the use of leak detection systems on pipelines in all locations, including outside of HCAs. The changes proposed by PHMSA in each of these proposals continue to remain under consideration by the agency. 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 OSHA's Process Safety Management ("PSM") regulations and the EPA's Risk Management Planning ("RMP") requirements at regulated facilities, PHMSA and one or more state regulators, including the Texas Railroad Commission, have in 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 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

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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 operations. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall cost of doing business, including our cost of planning, constructing and operating our plants, pipelines and other facilities. As a result of these laws and regulation, 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 on 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, in August 2015, several non-governmental organizations filed notice of intent to sue the EPA under RCRA for, among other things, the agency’s alleged failure to reconsider whether such RCRA exclusion for oilfield exploration, development and production wastes should continue to apply. It is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as “hazardous wastes,” resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes such as these examples in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense.

We currently own or lease sites that have been used over the years by prior owners and lessees and by us for various activities related to gathering, processing, storage and transmission of natural gas, NGLs, crude oil and 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, 2015 and 2014, accruals of $367 million and $401 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover estimated material environmental liabilities including, for example, certain matters assumed in connection with our acquisition of the HPL System, our acquisition of Transwestern, potential environmental liabilities for three sites that were formerly owned by Titan Energy Partners, L.P. or its predecessors, and the predecessor owner's share of certain environmental liabilities of ETC OLP.

The Partnership is subject to extensive and frequently changing federal, tribal, state and local laws and regulations, including those relating to the discharge of materials into the environment or that otherwise relate to the protection of the environment, waste management and the characteristics and composition of fuels. These laws and regulations require environmental assessment and remediation efforts at many of Sunoco, Inc.'s facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $344 million and $363 million at December 31, 2015 and 2014, respectively, which is included in the total accruals above. These legacy sites that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that are no longer operated by Sunoco, Inc., closed and/or sold refineries and other formerly owned sites. In December 2013, a wholly-owned captive insurance company was established for these legacy sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company. As of December 31, 2015 the captive insurance company held $238 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.

The Partnership currently owns or operates certain retail gasoline outlets where releases of petroleum products have occurred. Federal and state laws and regulations require that contamination caused by such certain of releases at these sites and at formerly owned sites be assessed and remediated to meet the applicable standards. Our obligation to remediate this type of contamination varies, depending on the extent of the release and the applicable laws and regulations. If the Partnership is eligible to participate, a portion of the remediation costs may be recoverable from the reimbursement fund of the applicable state, after any deductible has been met.

In general, 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.

In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (that is, it is less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2015, the aggregate of such additional estimated maximum reasonably possible losses, which relate to numerous individual sites, totaled approximately $5 million, which amount is in excess of the $367 million in environmental accruals recorded on December 31, 2015. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets, and in many cases, reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.

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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 $7 million, which is included in the total environmental accruals mentioned above. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCB contamination. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. 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 anticipates designating new non-attainment areas by October 1, 2017, and requiring states to revise implementation plans by October 1, 2020, with compliance dates anticipated between 2021 and 2037 determined by the degree of non-attainment. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended, also known as Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including hydrocarbon-bearing wastes, into state waters and waters of the United States. Pursuant to the Clean Water Act and similar state laws, a National Pollutant Discharge Elimination System, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In May 2015, the EPA issued a final rule that attempts to clarify the federal jurisdictional reach over waters of the United States but this rule has been stayed nationwide by the U.S. Sixth Circuit Court of Appeals as that appellate court and numerous district courts ponder lawsuits opposing implementation of the rule. To the extent the rule expands the scope of the CWA's jurisdiction, we could face 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. The PHMSA, the EPA, or various state regulatory agencies, has approved our oil spill emergency response plans that one 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. Based on findings made by the EPA that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD") and Title V permitting reviews for greenhouse gas emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to "best available control technology" standards for greenhouse gases, which are typically developed by the states. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce or sequester emissions of greenhouse gases associated with our operations and also could adversely affect demand for the natural gas and other hydrocarbon products that we transport, process, or otherwise handle in connection with our services.

In addition, the EPA adopted regulations requiring the annual reporting of greenhouse gas emissions from certain petroleum and natural gas sources in the United States, including onshore oil and natural gas production, processing, transmission, storage and distribution facilities. On October 22, 2015, the EPA published a final rule that expands the petroleum and natural gas system sources for which annual greenhouse gas emissions reporting is currently required to include greenhouse gas emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. We are monitoring greenhouse gas emissions from certain of our facilities pursuant to applicable greenhouse emissions reporting requirements, and management does not believe that the costs of these monitoring and reporting requirements will have a material adverse effect on our results of operations.

Various pieces of legislation to reduce emissions of, or to create cap and trade programs for, greenhouse gases have been proposed by the U.S. Congress over the past several years, but no proposal has yet passed. Numerous states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our own operations, and it could also adversely affect demand for our transportation, storage and processing services by reducing demand for oil, natural gas and NGLs. For example, in August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including oil and natural gas production and natural gas processing and transmission facilities as part of an overall effort to reduce methane emissions by up to 45 percent from 2012 levels in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. Although it is not possible at this time to predict how new methane restrictions would impact our business or how or when the United State might impose restrictions on greenhouse gases as a result of the international agreement agreed to in Paris, any new legal requirements that impose more stringent requirements on the emission

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of greenhouse gases from our operations could result in increased compliance costs or additional operating restrictions, which could have an adverse effect on our business, financial condition and results of operations. Moreover, such new legislation or regulatory programs could also increase the cost to our oil and natural gas exploration and production customers and thereby reduce demand for oil and natural gas, which could reduce the demand for our services to our customers.

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

Employee Health and Safety. We are subject to the requirements of the federal OSHA and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our past 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 January 29, 2016, we employed 9,466 persons, 1,731 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. You may read and copy any materials we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. In addition, the SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We provide electronic access, free of charge, to our periodic and current reports on our Internet website located at http://www.energytransfer.com. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC. Information contained on our website is not part of this report.

ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our structure as a limited partnership, our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. Panhandle and Sunoco Logistics file Annual Reports on Form 10-K that include risk factors that can be reviewed for further information. The risk factors set forth below, and those included in Panhandle's and Sunoco Logistics' 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 holders of our Common Units or other partnership securities depends upon the amount of cash we generate from our operations. 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, crude oil and products transported in our pipelines and gathering systems;
- the level of throughput in our processing and treating operations;
- the fees we charge and the margins we realize for our services;

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- the price of natural gas, NGLs, crude oil and products;
- the relationship between natural gas, NGL and crude oil prices;
- the amount of cash distributions we receive with respect to the Sunoco LP and Sunoco Logistics common units that we or our subsidiaries own;
- the weather in our operating areas;
- the level of competition from other midstream, transportation and storage and retail marketing companies 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 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 our Unitholders.

Furthermore, 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.

We may sell additional limited partner interests, diluting existing interests of Unitholders.

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

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

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

Sunoco Logistics' and Sunoco LP's partnership agreements allow the issuance of an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by Sunoco Logistics or Sunoco LP will have the following effects:

- Unitholders' current proportionate ownership interest in Sunoco Logistics will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;

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- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of Sunoco Logistics' common units may decline.

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

Future sales of our units or other limited partner interests in the public market could reduce the market price of Unitholders' limited partner interests.

As of December 31, 2015, ETE owned 2.6 million ETP Common Units. If ETE were to sell and/or distribute its Common Units to the holders of its equity interests in the future, those holders may dispose of some or all of these units. The sale or disposition of a substantial portion of these units in the public markets could reduce the market price of our outstanding Common Units.

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

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

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

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

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

As of December 31, 2015, we had approximately $28.68 billion of consolidated debt, excluding the debt of our joint ventures. Our level of indebtedness affects our operations in several ways, including, among other things:

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

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.

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Increases in interest rates could adversely affect our business, results of operations, cash flows and financial condition.
In addition to our exposure to commodity prices, we have exposure to changes in interest rates. Approximately $3.59 billion of our consolidated debt as of December 31, 2015 bears interest at variable interest rates and the remainder bears interest at fixed rates. To the extent that we have debt with floating interest rates, our results of operations, cash flows and financial condition could be materially adversely affected by increases in interest rates. We manage a portion of our interest rate exposures by utilizing interest rate swaps.
An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our Common Units. Any such reduction in demand for our Common Units resulting from other more attractive investment opportunities may cause the trading price of our Common Units to decline.
The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile.
The credit and business risk profiles of our General Partner, and of ETE as the indirect owner of our General Partner, may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our General Partner and ETE 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.
ETE 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 ETE will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us, ETP GP and ETP LLC from the entities that control ETP GP (ETE and its general partner), our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of such entities were viewed as substantially lower or riskier than ours.
Unitholders have limited voting rights and are not entitled to elect the General Partner or its directors. In addition, even if Unitholders are dissatisfied, they cannot easily remove the General Partner.
Unlike the holders of common stock in a corporation, Unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our General Partner and will have no right to elect our General Partner on an annual or other continuing basis. Although our General Partner has a contractually-limited fiduciary duty to our Unitholders, the directors of our General Partner and its general partner have a fiduciary duty to manage the General Partner and its general partner in a manner beneficial to the owners of those entities.
Furthermore, if the Unitholders are dissatisfied with the performance of our General Partner, they may be unable to remove our General Partner. The General Partner generally may not be removed except upon the vote of the holders of 66 $^{2}/3$% of the outstanding units voting together as a single class, including units owned by the General Partner and its affiliates. As of December 31, 2015, ETE and its affiliates held approximately 0.5% of our outstanding Common Units and our officers and directors held less than 1% of our outstanding Common Units.
Furthermore, Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than the General Partner and its affiliates, cannot be voted on any matter.
Our General Partner may, in its sole discretion, approve the issuance of partnership securities and specify the terms of such partnership securities.
Pursuant to our partnership agreement, our General Partner has the ability, in its sole discretion and without the approval of the Unitholders, to approve the issuance of securities by the Partnership at any time and to specify the terms and conditions of such securities. The securities authorized to be issued may be issued in one or more classes or series, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of partnership securities), as shall be determined by our General Partner, including:
- the right to share in the Partnership's profits and losses;
- the right to share in the Partnership's distributions;

- the rights upon dissolution and liquidation of the Partnership;
- whether, and the terms upon which, the Partnership may redeem the securities;
- whether the securities will be issued, evidenced by certificates and assigned or transferred; and

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- 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.

Please see "We may sell additional limited partner interests, diluting existing interests of Unitholders." above.

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.

Unitholders may be required to sell their units to the General Partner at an undesirable time or price.

If at any time less than 20% of the outstanding units of any class are held by persons other than the General Partner and its affiliates, the General Partner will have the right to acquire all, but not less than all, of those units at a price no less than their then-current market price. As a consequence, a Unitholder may be required to sell their Common Units at an undesirable time or price. The General Partner may assign this purchase right to any of its affiliates or to us.

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, including Sunoco Logistics. 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.

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

Through our ownership of equity interests in Sunoco Partners, the holder of the incentive distribution rights in Sunoco Logistics, we are entitled to receive our pro rata share of specified percentages of total cash distributions made by Sunoco Logistics as it reaches established target cash distribution levels as specified in the Sunoco Logistics partnership agreement. We currently receive our pro rata share of cash distributions from Sunoco Logistics based on the highest incremental percentage, 48%, to which Sunoco Partners is entitled pursuant to its incentive distribution rights in Sunoco Logistics. A decrease in the amount of distributions by Sunoco Logistics to less than $0.2638 per common unit per quarter would reduce Sunoco Partners' percentage of the incremental cash distributions above $0.0958 per common unit per quarter from 48% to 35%. As a result, any such reduction in quarterly cash distributions from Sunoco Logistics would have the effect of disproportionately reducing the amount of all distributions that we receive from Sunoco Logistics based on our ownership interest in the incentive distribution rights in Sunoco Logistics as compared to cash distributions we receive from Sunoco Logistics on our General Partner interest in Sunoco Logistics and our Sunoco Logistics common units.

Sunoco Logistics is not prohibited from competing with us.

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

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.

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

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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 Unitholders and our General Partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

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

A downgrade of our credit ratings might 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 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.

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Risks Related to Conflicts of Interest

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 ETE. 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 ETE. 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.

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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.

ETE 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 ETE, 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 ETE as its sole owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of ETE 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 ETE, in resolving conflicts of interest, thereby limiting its fiduciary duties to us.
- Our General Partner's affiliates, including ETE, 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 ETE.
- Neither our partnership agreement nor any other agreement requires ETE or its affiliates to pursue a business strategy that favors us. The directors and officers of the general partners of ETE 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 ETE who provide advice to us also may devote significant time to the businesses of ETE 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 joint ventures have their own governing boards, and we may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in our or the joint venture's best interests. Likewise, we may be unable to prevent actions of the joint venture.

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We 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 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 are subject to risks of loss resulting from nonpayment or nonperformance by our customers. The current commodity price volatility and the tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment 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 results of operations and operating cash flows.

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 and oil that are beyond our control.

The prices for natural gas, NGLs and oil (including refined petroleum products) reflect market demand that fluctuates with changes in global and U.S. economic conditions and other factors, including:

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

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

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

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

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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 also face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations operated by fully integrated major oil companies and other well-recognized national or regional retail outlets, often selling gasoline or merchandise at aggressively competitive prices. The actions of our retail marketing competitors, including the impact of imports, could lead to lower prices or reduced margins for the products we sell, which could have an adverse effect on our business or results of operations.

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

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

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.

We are entirely dependent upon third parties for the supply of refined products such as gasoline and diesel for our retail marketing business.

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

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.

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

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

Our natural gas and NGL 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,

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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.

In addition, we do not own all of the land on which our retail service stations are located. We have rental agreements for approximately 32.6% of the company-operated retail service stations where we currently control the real estate and we have rental agreements for certain logistics facilities. As such, we are subject to the possibility of increased costs under rental agreements with landowners, primarily through rental increases and renewals of expired agreements. We are also subject to the risk that such agreements may not be renewed. Additionally, certain facilities and equipment (or parts thereof) used by us are leased from third parties for specific periods. Our 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 our financial condition, results of operations and cash flows.

We 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, 2015, our consolidated balance sheet reflected $5.43 billion of goodwill and $4.42 billion of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners’ capital and balance sheet leverage as measured by debt to total capitalization.

During the fourth quarter of 2015, we performed goodwill impairment tests on our reporting units and recognized goodwill impairments of: (i) $99 million in the Transwestern reporting unit due primarily to the market declines in current and expected future commodity prices in the fourth quarter of 2015 and (ii) $106 million in the Lone Star

Refinery Services reporting unit due primarily to changes in assumptions related to potential future revenues decrease as well as the market declines in current and expected future commodity prices.

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If we 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 increase 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.

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 2015, Kinder Morgan, Inc., EDF Inc., Natural Gas Exchange Inc., Calpine Energy Services, L.P., and XTO Energy Inc. collectively accounted for approximately 27.1% of our intrastate transportation and storage revenues. With respect to our interstate transportation and storage operations we have an agreement with Chesapeake Energy Marketing, Inc. that provides for a 15-year commitment for firm transportation capacity on the Tiger pipeline of approximately 1.0 Bcf/d. We also have agreements with other shippers that provide for 10-year commitments for firm transportation capacity on the Tiger pipeline totaling approximately 1.4 Bcf/d, bringing the total shipper commitments to approximately 2.4 Bcf/d of firm transportation service in the Tiger pipeline project. Transwestern generates the majority of its revenues from long-term and short-term firm transportation contracts with natural gas producers, local distribution companies and end-users.

Our joint ventures, FEP and Citrus, also depend on key customers for the transport of natural gas through their pipelines. FEP has 10- and 12-year agreements from a small number of major shippers for approximately 1.85 Bcf/d of firm transportation service on the 2.0 Bcf/d Fayetteville Express Pipeline, while Citrus has 10- and 14-year agreements with its top two customers which accounted for 60% of its 2015 revenue.

During 2015, Chesapeake Energy Marketing, Inc., Ameren Corporation, EnCana Marketing (USA), Inc., Exelon Generation Company, LLC and Petrohawk Energy Corporation collectively accounted for 32.1% of our interstate transportation and storage revenues.

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 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 tariffs rates on its own initiative or upon receipt of a complaint filed by a third party. The FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. The FERC has recently exercised this authority with respect to several other pipeline companies. If the FERC were to initiate a proceeding against 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. It is currently the FERC's policy to permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential income tax liability on their public utility income attributable to all partnership or limited liability company interests, to the extent that the ultimate owners have an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Under the FERC's policy, we thus remain eligible to include an income tax allowance in the tariff rates we charge for interstate natural gas transportation. The effectiveness of the FERC's policy and the application of that policy remain subject to future challenges, refinement or change by the FERC or the courts.
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 do so 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.
Rate regulation or market conditions may not allow us to recover the full amount of increases in the costs of our crude oil and products pipeline operations.
Transportation provided on our common carrier interstate crude oil and 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 addition, if the FERC's indexing methodology changes, the new methodology could materially and adversely affect our financial condition, results of operations or cash flows.

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Under the EPAct 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 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. Lone Star’s NGL pipeline also commenced the interstate transportation of NGLs in 2013, which is subject to FERC’s jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. Both intrastate and interstate NGL transportation services must be provided in a manner that is just, reasonable, and non-discriminatory. The tariff rates established for interstate services were based on a negotiated agreement; however if FERC's rate making methodologies were imposed, they may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. In addition, the rates, terms and conditions for shipments of crude oil, petroleum products and NGLs on our pipelines are subject to regulation by FERC if the NGLs are transported in interstate or foreign commerce whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all crude oil, petroleum products and NGLs on our pipelines, FERC regulation could be triggered by our customers' transportation decisions. 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, as amended by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources, and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline 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 instance, changes to regulations governing the safety of gas and hazardous liquid transmission pipelines and gathering lines are being considered by PHMSA, including, for example, revising the definitions of "high consequence areas" and "gathering lines," and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, the PHMSA has considered changes to its rural gathering exemption, including publishing a notice of proposed rulemaking relating to hazardous liquid pipelines in October 2015, in which the agency is seeking public comment on, among other things, extending reporting requirements to all gravity and gathering lines, requiring periodic inline integrity assessments of pipelines that are located outside of high consequence areas, and requiring the use of leak detection systems on pipelines in all locations, including outside of high consequence areas.

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 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, reauthorizing the federal pipeline safety programs of PHMSA through 2015 and requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, material strength testing, and verification of the maximum allowable pressure of certain pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and from $1.0 million to $2.0 million for a related series of violations. Moreover, new pipeline safety legislation that would reauthorize the federal pipeline safety programs of PHMSA through 2019 is expected to be under consideration by Congress in 2016. One bill introduced in late 2015, the SAFE PIPES, has already been approved by the Senate Committee on Commerce, Science, and Transportation and is now subject to consideration by the U.S. Senate. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act or any new pipeline safety legislation as well as any implementation of PHMSA rules thereunder 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 have a material adverse effect on our results of operations or financial position.

Our business involves the generation, handling and disposal of hazardous substances, hydrocarbons and wastes and may be adversely affected by environmental and worker health and safety laws and regulations.

Our operations are 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 our operations, 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 operations. 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, 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 inherent to 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. 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 previously able to satisfy the more stringent NOx 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.

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

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

Along with other refiners, manufacturers and sellers of gasoline, Sunoco, Inc. 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 Sunoco, Inc. These allegations or other product liability claims against Sunoco, Inc. could have a material adverse effect on our business or results of operations.

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

The EPA has determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted rules under the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for greenhouse gas emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting greenhouse gases and meeting “best available control technology” standards for those greenhouse gas emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of greenhouse gas emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States, which includes certain of our operations. More recently, on October 22, 2015, the EPA published a final rule that expands the petroleum and natural gas system sources for which annual greenhouse gas emissions reporting is currently required to include greenhouse gas emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to

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perform natural gas compression, dehydration and acid gas removal. While Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of greenhouse gases or otherwise restricts emissions of greenhouse gases from our equipment and operations could require us to incur significant added costs to reduce emissions of greenhouse gases or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. For example, in August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including oil and natural gas production and natural gas processing and transmission facilities as part of an overall effort to reduce methane emissions by up to 45 percent from 2012 levels in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets

The adoption of the Dodd-Frank Act could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business, resulting in our operations becoming more volatile and our cash flows less predictable.

Congress has adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), a comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The legislation was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. While certain regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

The Dodd-Frank Act expanded the types of entities that are required to register with the CFTC and the SEC as a result of their activities in the derivatives markets or otherwise become specifically qualified to enter into derivatives contracts. We will be required to assess our activities in the derivatives markets, and to monitor such activities on an ongoing basis, to ascertain and to identify any potential change in our regulatory status.

Reporting and recordkeeping requirements also could significantly increase operating costs and expose us to penalties for non-compliance, and require additional compliance resources. Added public transparency as a result of the reporting rules may also have a negative effect on market liquidity which could also negatively impact commodity prices and our ability to hedge.

In October 2011, the CFTC has also issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. However, in September 2012, the CFTC’s position limits rules were vacated by the U.S. District Court for the District of Columbia. In November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. The associated rules require us, in connection with covered derivative activities, to comply with such requirements or take steps to qualify for an exemption to such requirements. We must obtain approval from the board of directors of our General Partner and make certain filings in order to rely on the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks. The application of mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing and exchange trading.

In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. The application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the

swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact our liquidity and reduce cash available to us for capital expenditures, reducing our ability to execute hedges to reduce risk and protect cash flow.
Rules promulgated under the Dodd-Frank Act further defined forwards as well as instances where forwards may become swaps. Because the CFTC rules, interpretations, no-action letters, and case law are still developing, it is possible that some arrangements that previously qualified as forwards or energy service contracts may fall in the regulatory category of swaps or options. In addition, the CFTC's rules applicable to trade options may further impose burdens on our ability to conduct our traditional hedging operations and could become subject to CFTC investigations in the future.

The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, or reduce our ability to monetize or restructure existing derivative contracts. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, if we fail to comply with applicable laws, rules or regulations, we may be subject to fines, cease-and-desist orders, civil and criminal penalties or other sanctions.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail 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 facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. 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 our Unitholders and, accordingly, adversely affect the market price of our Common Units.

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.

In response to the Deepwater Horizon incident and resulting oil spill in the United States Gulf of Mexico in 2010, the federal Bureau of Ocean Energy Management (“BOEM”) and the federal Bureau of Safety and Environmental Enforcement (“BSEE”), each agencies of the U.S. 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 restrictions together with any uncertainties or inconsistencies in current 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 adversely affect or delay new drilling and ongoing development efforts. In addition, new regulatory initiatives may be adopted or enforced by the BOEM and/or the BSEE in the future that could result in additional 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 September 2015, the BOEM issued draft guidance that would bolster supplemental bonding procedures for the decommissioning of offshore wells, platforms, pipelines, and other facilities. The BOEM is expected to issue the draft guidance in the form of a final Notice to Lessees and Operators by no later than mid-2016. These recent or 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 similar to the Deepwater Horizon incident were to occur in the future, the United States or other countries could elect to again 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 through Sunoco Logistics' operations are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications could reduce our throughput volume, require us to incur additional handling costs or require the expenditure of significant capital. In addition, different product specifications for different markets impact the fungibility of products transported and stored in our pipeline systems and terminal facilities and could require the construction of additional storage to segregate products with different specifications. We may be unable to recover these costs through increased revenues.

In addition, our 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, 2015, approximately 18% 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.

Governmental regulations and policies, particularly in the areas of taxation, energy and the environment, have a significant impact on our retail marketing business.

Federally mandated standards for use of renewable biofuels, such as ethanol and biodiesel in the production of refined products, are transforming traditional gasoline and diesel markets in North America. These regulatory mandates present production and logistical challenges for both the petroleum refining and ethanol industries, and may require us to incur additional capital expenditures or expenses particularly in our retail marketing business. We may have to enter into arrangements with other parties to meet our obligations to use advanced biofuels, with potentially uncertain supplies of these new fuels. If we are unable to obtain or maintain sufficient quantities of ethanol to support our blending needs, our sale of ethanol blended gasoline could be interrupted or suspended which could result in lower profits. There also will be compliance costs related to these regulations. We may experience a decrease in demand for refined petroleum products due to new federal requirements for increased fleet mileage per gallon or due to replacement of refined petroleum products by renewable fuels. In addition, tax incentives and other subsidies making renewable fuels more competitive with refined petroleum products may reduce refined petroleum product margins and the ability of refined petroleum products to compete with renewable fuels. A structural expansion of production capacity for such renewable biofuels could lead to significant increases in the overall production, and available supply, of gasoline and diesel in markets that we supply. In addition, a significant shift by consumers to more fuel-efficient vehicles or alternative fuel vehicles (such as ethanol or wider adoption of gas/electric hybrid vehicles), or an increase in vehicle fuel economy, whether as a result of technological advances by manufacturers, legislation mandating or encouraging higher fuel economy or the use of alternative fuel, or otherwise, also could lead to a decrease in demand, and reduced margins, for the refined petroleum products that we market and sell.

It is possible that any, or a combination, of these occurrences could have a material adverse effect on Sunoco, Inc.'s business or results of operations.

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We have outsourced various functions related to our retail marketing business to third-party service providers, which decreases our control over the performance of these functions. Disruptions or delays of our third-party outsourcing partners could result in increased costs, or may adversely affect service levels. Fraudulent activity or misuse of proprietary data involving our outsourcing partners could expose us to additional liability.

Sunoco, Inc. has previously outsourced various functions related to our retail marketing business to third parties and expects to continue this practice with other functions in the future.

While outsourcing arrangements may lower our cost of operations, they also reduce our direct control over the services rendered. It is uncertain what effect such diminished control will have on the quality or quantity of products delivered or services rendered, on our ability to quickly respond to changing market conditions, or on our ability to ensure compliance with all applicable domestic and foreign laws and regulations. We believe that we conduct appropriate due diligence before entering into agreements with our outsourcing partners. We rely on our outsourcing partners to provide services on a timely and effective basis. Although we continuously monitor the performance of these third parties and maintain contingency plans in case they are unable to perform as agreed, we do not ultimately control the performance of our outsourcing partners. Much of our outsourcing takes place in developing countries and, as a result, may be subject to geopolitical uncertainty. The failure of one or more of our third-party outsourcing partners to provide the expected services on a timely basis at the prices we expect, or as required by contract, due to events such as regional economic, business, environmental or political events, information technology system failures, or military actions, could result in significant disruptions and costs to our operations, which could materially adversely affect our business, financial condition, operating results and cash flow.

Our failure to generate significant cost savings from these outsourcing initiatives could adversely affect our profitability and weaken Sunoco, Inc.'s competitive position. Additionally, if the implementation of our outsourcing initiatives is disruptive to our retail marketing business, we could experience transaction errors, processing inefficiencies, and the loss of sales and customers, which could cause our business and results of operations to suffer.

As a result of these outsourcing initiatives, more third parties are involved in processing our retail marketing information and data. Breaches of security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information or sensitive or confidential data about our retail marketing business or our clients, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose us to a risk of loss or misuse of this information, result in litigation and potential liability for us, lead to reputational damage to the Sunoco, Inc. brand, increase our compliance costs, or otherwise harm our business.

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

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

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.

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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 principal manufacturers of components for our natural gas compression equipment include Caterpillar, Inc. for engines, Air-X-Changers for coolers and Ariel Corporation for compressors and frames. 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 two vendors, Spitzer Industries Corp. and Standard Equipment Corp., 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 certain of these sources could have a negative impact on our results of operations and could damage our customer relationships.
Mergers among Sunoco Logistics' customers and competitors could result in lower volumes being shipped on its pipelines or products stored in or distributed through its terminals, or reduced crude oil marketing margins or volumes.
Mergers between existing customers could provide strong economic incentives for the combined entities to utilize their existing systems instead of Sunoco Logistics' systems in those markets where the systems compete. As a result, Sunoco Logistics could lose some or all of the volumes and associated revenues from these customers and could experience difficulty in replacing those lost volumes and revenues, which could materially and adversely affect our results of operations, financial position, or cash flows.
A portion of Sunoco Logistics' general and administrative services have been outsourced to third-party service providers. Fraudulent activity or misuse of proprietary data involving its outsourcing partners could expose us to additional liability.
Sunoco Logistics utilizes both affiliated entities and third parties in the processing of its information and data. Breaches of its security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information, or sensitive or confidential data about Sunoco Logistics or its customers, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose Sunoco Logistics to a risk of loss, or misuse of this information, result in litigation and potential liability for Sunoco Logistics, lead to reputational damage, increase our compliance costs, or otherwise harm its business.
A material decrease in demand or distribution of crude oil available for transport through Sunoco Logistics' pipelines or terminal facilities could materially and adversely affect our results of operations, financial position, or cash flows.
The volume of crude oil transported through Sunoco Logistics' crude oil pipelines and terminal facilities depends on the availability of attractively priced crude oil produced or received in the areas serviced by its assets. A period of sustained crude oil price declines could lead to a decline in drilling activity, production and import levels in these areas. Similarly, a period of sustained increases in the price of crude oil supplied from any of these areas, as compared to alternative sources of crude oil available to Sunoco Logistics' customers, could materially reduce demand for crude oil in these areas. In either case, the volumes of crude oil transported in Sunoco Logistics' crude oil pipelines and terminal facilities could decline, and it could likely be difficult to secure alternative sources of attractively priced crude oil supply in a timely fashion or at all. If Sunoco Logistics is unable to replace any significant volume declines with additional volumes from other sources, our results of operations, financial position, or cash flows could be materially and adversely affected.

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 U.S. 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 U.S. refining centers. Federal regulators have issued a safety advisory warning that Bakken crude oil may be more volatile than many other North American

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crude oils and reinforcing the requirement to properly test, characterize, classify, and, if applicable, sufficiently degasify hazardous materials prior to and during transportation. Much of 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 the PHMSA, issued a rule implementing new rail car standards and railroad operating procedures. Changing operating practices, as well as new regulations on tank car standards and shipper classifications, could increase the time required to move crude oil from production areas of facilities, increase the cost of rail transportation, and decrease the efficiency of transportation of crude oil by rail, any of which could materially reduce the volume of crude oil received by rail and adversely affect our financial condition, results of operations, and cash flows.

LCL is dependent on project financing to fund the costs necessary to construct the liquefaction project. If project financing is unavailable to supply the funding necessary to complete the liquefaction project, LCL may not be able to secure alternative funding and affirmative FID may not be achieved.

LCL, an entity owned 60% by ETE and 40% by ETP, is in the process of developing a liquefaction project in conjunction with BG Group plc (“BG”) pursuant to a project development agreement entered into in September 2013. Pursuant to this agreement, each of LCL and BG are obligated to pay 50% of the development expenses for the liquefaction project, subject to reimbursement by the other party if such party withdraws from the project prior to both parties making a final investment decision (“FID”) to become irrevocably obligated to fully develop the project, subject to certain exceptions. Through December 31, 2015, LCL had incurred $89 million of development costs associated with the liquefaction project that were funded by ETE and ETP, and ETE and ETP have indicated that they intend to provide the funding necessary for the remaining development costs, but they have no obligation to do so. If ETE and ETP are unwilling or unable to provide funding to LCL for their share of the remaining development costs, or if BG is unwilling or unable to provide funding for its share of the remaining development costs, the liquefaction project could be delayed or cancelled.

The liquefaction project is subject to the right of each of LCL and BG to withdraw from the project in its sole discretion at any time prior to an affirmative FID.

The project development agreement provides that either LCL or BG may withdraw from the liquefaction project at any time prior to each party making an affirmative FID. LCL’s determination of whether to reach an affirmative FID is expected to be based upon a number of factors, including the expected cost to construct the liquefaction facility, the expected revenue to be generated by LCL pursuant to the terms of the liquefaction services agreement anticipated to be entered into between LCL and BG in connection with both parties reaching an affirmative FID, and the terms and conditions of the financing for the construction of the liquefaction facility. BG’s determination of whether to reach an affirmative FID is expected be based on a number of factors, including the expected tolling charges it would be required to pay under the terms of the liquefaction services agreement, the costs anticipated to be incurred by BG to purchase natural gas for delivery to the liquefaction facility, 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) over the expected 25-year term of the liquefaction services agreement. As the tolling charges payable to LCL under the liquefaction services agreement are anticipated to be based on a rate of return formula tied to the construction costs and financing costs for the liquefaction facility, these costs are anticipated to also have a significant bearing with respect to BG’s determination whether to reach an affirmative FID. As 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 price of LNG in foreign markets, 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 both LCL and BG will reach an affirmative FID to construct the liquefaction facility.

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

The liquefaction project remains subject to approvals and permits from the U.S. Army Corps of Engineers ("USACE") for wetlands mitigation and permanent and temporary marine dock modifications and dredging at the Lake Charles LNG facility. Furthermore, while a subsidiary of BG 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. Certain of the permits and approvals must be obtained before construction on the liquefaction project can begin and are still under review by state and federal authorities. We do not know whether or when any such approvals or permits can be obtained, or whether any existing or potential interventions or other actions by third parties will interfere with its ability to obtain and maintain such permits

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or approvals. The failure by LCL to timely receive and maintain the remaining approvals necessary to complete and operate the liquefaction project could have a material adverse effect on its operations and financial condition.

Tax Risks to Common 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 Common Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS, 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 on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and we would likely pay additional state income taxes at varying rates. Distributions to Unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to Unitholders. Because a tax would then be imposed upon us as a corporation, our cash available for distribution to Unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of our Common Units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or 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. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our case available for distribution to our Unitholders.

On November 2, 2015, President Obama signed into law the Bipartisan Budget Act of 2015 (the Act). The Act includes significant changes to the rules governing the audits of entities that are treated as partnerships for U.S. federal income tax purposes. The new rules under the Act, which are effective for tax years beginning after December 31, 2017, repeal and replace the regimes under current "TEFRA" audit provisions for partnerships. The Act allows a partnership to elect to apply these provisions to any return of the partnership filed for partnership taxable years beginning after the date of the enactment, November 2, 2015. The Partnership does not intend to elect to apply these provisions for any tax return filed for partnership taxable years beginning before January 1, 2018.

Under the new streamlined audit procedures, a partnership would be responsible for paying the imputed underpayment of tax resulting from the audit adjustments in the adjustment year even though partnerships are "pass through entities." However, as an alternative to paying the imputed underpayment of tax at the partnership level, a partnership may elect to provide the audit adjustment information to the reviewed year partners, whom in turn would be responsible for paying the imputed underpayment of tax in the adjustment year.

Should a partnership not elect to pass the audit adjustments on to its partners, the partnerships' imputed underpayment generally would be determined at the highest rate of tax in effect for the reviewed year. Currently, the highest rate of tax would be 39.6% for individual taxpayers. However, the Act authorizes the Treasury to establish procedures whereby the imputed underpayment amount may be modified to more accurately reflect the amount owed, if the partnership can substantiate a lower tax rate or demonstrate a portion of the imputed underpayment amount is allocable to a partner that would not owe tax (a tax exempt entity) or a partner has already paid the tax. It is not yet clear how state and local tax authorities will respond to the new regime. The Partnership is closely monitoring the development and issuance of regulations or other additional guidance under the new partnership audit regime.

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If the IRS contests the federal income tax positions we take, the market for our Common Units may be adversely affected and the costs of any such contest will reduce cash available for distributions to our Unitholders. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to you.
We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our Common Units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne by us reducing the cash available for distribution to our Unitholders.
Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our Unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, Unitholders during that taxable year would bear the expense of the adjustment even if they were not Unitholders during the audited taxable year.
Unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.
Unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from the taxation of their share of our taxable income.
In response to current market conditions, we may engage in transactions to delever the Partnership and manage our liquidity that may result in income and gain to our Unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result “cancellation of indebtedness income” (also referred to as “COD income”) being allocated to our Unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the Unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.
Tax gain or loss on disposition of our Common Units could be more or less than expected.
If Unitholders sell their Common Units, they will recognize a gain or loss equal to the difference between the amount realized and the tax basis in those Common Units. Because distributions in excess of the Unitholder’s allocable share of our net taxable income result in a decrease in the Unitholder’s tax basis in their Common Units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the Unitholder if they sell such units at a price greater than their tax basis in those units, even if the price received is less than their original cost. In addition, because the amount realized includes a Unitholder’s share of our nonrecourse liabilities, if a Unitholder sells units, the Unitholder may incur a tax liability in excess of the amount of cash received from the sale.
A substantial portion of the amount realized from the sale of your units, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation recapture. Thus, you may recognize both ordinary income and capital loss from the sale of your units if the amount realized on a sale of your units is less than your adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which you sell your units, you may

recognize ordinary income from our allocations of income and gain to you prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning Common Units that may result in adverse tax consequences to them.

Investment in Common Units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to Unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be “unrelated business

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taxable income" and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective tax rate applicable to non-U.S. persons, and each non-U.S. person will be required to file United States federal and state income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or non-U.S. person, you should consult your tax advisor before investing in our common units.

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

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

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

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

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

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

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

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a Unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units.

In that case, the Unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

In determining the items of income, gain, loss and deduction allocable to our Unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

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

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

We will be considered to have technically terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all Unitholders which would require us to file two federal partnership tax returns (and our Unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a Unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such Unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes on the technical termination date, and would be required to make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred. The IRS has recently announced a relief procedure whereby a publicly traded partnership that has technically terminated may be permitted to provide only a single Schedule K-1 to Unitholders for the two tax years within the fiscal year in which the termination occurs.

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

In addition to federal income taxes, the Unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. 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, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in "Item 1. Business." In addition, we own office buildings for our executive offices in Dallas, Texas and office buildings in Newton Square, Pennsylvania and Houston, Corpus Christi 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

Sunoco, Inc., along with other refiners, manufacturers and sellers of gasoline, is a defendant in lawsuits alleging MTBE contamination of groundwater. The plaintiffs typically include water purveyors and municipalities responsible for supplying drinking water and governmental authorities. The plaintiffs assert primarily product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. The plaintiffs in all of the cases 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, 2015, Sunoco, Inc. is a defendant in six cases, including cases initiated by the States of New Jersey, Vermont, the Commonwealth of Pennsylvania, and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action and one case by the City of Breaux Bridge in the USDC in the Western District of Louisiana. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court. The New Jersey, Puerto Rico, Vermont, and Pennsylvania cases assert natural resource damage claims.

Fact discovery has concluded with respect to an initial set of 19 sites each that will be the subject of the first trial phase in the New Jersey case and the initial Puerto Rico case. In November 2015, Sunoco along with other co-defendants agreed to a global settlement in principle of the City of Breaux Bridge MTBE case. Insufficient information has been developed about the plaintiffs’ legal theories or the facts with respect to statewide natural resource damage claims to provide an analysis of the ultimate potential liability of Sunoco, Inc. in these matters. It is reasonably possible that a loss may be realized; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. Management believes that an adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any said adverse determination occurs, but does not believe that any such adverse determination would have a material adverse effect on the Partnership’s consolidated financial position.

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

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

In September 2013, the Pennsylvania Department of Environmental Protection (“PADEP”) issued a Notice of Violation and proposed penalties based on alleged violations of various safety regulations relating to the November 2008 products release by Sunoco Pipeline L.P., a subsidiary of Sunoco Logistics, in Murrysville, Pennsylvania. In the fourth quarter 2015, the Partnership reached an agreement with the PADEP and settled this matter for $0.8 million, which was paid in December 2015.

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In November 2013, the DOT issued a Notice of Violation and proposed penalties in excess of $0.1 million based on alleged violations of various safety regulations relating to the February 2012 products release by FGT in Baton Rouge, Louisiana. We received an initial assessment of $0.2 million associated with this release. In January 2016, FGT resolved this matter by paying a portion of this assessment, without material impact, and submitting a compliance plan. DOT issued a Final Order resolving the matter, subject to the completion of certain compliance plan activities which are ongoing.

On or around December 24, 2014, PHMSA issued to Panhandle a Notice of Proposed Safety Order (the “Notice”) regarding the ETP\Panhandle pipeline system. The Notice stated that PHMSA had initiated an investigation of the safety of the ETP/Panhandle pipeline system and specifically referenced two incidents: 1) a November 28, 2013, incident on ETP/Panhandle’s 400 line approximately 4.7 miles downstream of the Houstonia compressor station near Hughesville, Missouri, and 2) an October 13, 2014, failure on the ETP/Panhandle 100 line near Centerview, Missouri. The Notice further mentioned other incidents on the ETP/Panhandle pipeline system that PHMSA claims to have addressed with ETP/Panhandle. The Notice also stated that “[a]s a result of [PHMSA’s] investigation, it appears that conditions exist on the ETP/Panhandle pipeline system that pose a pipeline integrity risk to public safety, property or the environment.” ETP/Panhandle responded to the Notice and participated in a settlement of this proceeding and entry into a Consent Agreement effective as of April 1, 2015.

In April 2015, the PHMSA issued two separate Notices of Probable Violation (“NOPV”) related to Sunoco Logistics’ West Texas Gulf pipeline in connection with repairs being carried out on the pipeline. The NOPVs propose penalties in excess of $0.1 million, and Sunoco Logistics is currently in discussions with PHMSA to resolve these matters. The timing or outcome of these matters cannot be reasonably determined at this time, however, Sunoco Logistics does not expect there to be a material impact to its results of operations, cash flows, or financial position.

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

One of the directors of our general partner, James R. (Rick) Perry, the former Governor of Texas, has been named the subject of a pending criminal proceeding arising from a political dispute between the Governor and the political leadership of the Public Integrity Unit of the Travis County (Texas) District Attorney’s Office. On August 15, 2014, the Travis County District Attorney’s Office caused a county grand jury to return an indictment against Governor Perry for “abuse of official capacity” and “coercion of public servant” in retaliation for constitutional protected statements Governor Perry made in his capacity as Governor of the State of Texas that he would veto funding for the Travis County Public Integrity Unit if District Attorney Rosemary Lehmberg did not resign after pleading guilty to a charge of driving while intoxicated. Governor Perry pled “not guilty” to those charges and, as of February 2016, all of the charges have been dismissed.

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

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

Our Common Units are listed on the NYSE under the symbol "ETP." The following table sets forth, for the periods indicated, the high and low sales prices per Common Unit, as reported on the NYSE Composite Tape, and the amount of cash distributions paid per Common Unit for the periods indicated.

	Price Range		Cash
	High	Low	Distribution[1]
Fiscal Year 2015			
Fourth Quarter	$47.53	$27.44	$1.0550
Third Quarter	54.64	36.84	1.0550
Second Quarter	59.37	51.73	1.0350
First Quarter	66.58	53.25	1.0150
Fiscal Year 2014			
Fourth Quarter	$69.66	$53.12	$0.9950
Third Quarter	64.13	54.64	0.9750
Second Quarter	58.20	53.62	0.9550
First Quarter	57.00	52.49	0.9350

(1) Distributions are shown in the quarter with respect to which they relate. Please see "Cash Distribution Policy" below for a discussion of our policy regarding the payment of distributions.

Description of Units

Common Units

As of February 19, 2016, there were approximately 595,972 individual Common Unitholders, which includes Common Units held in street name. The Common Units are entitled to distributions of Available Cash as described below under "Cash Distribution Policy."

Class E Units

In conjunction with our purchase of the capital stock of Heritage Holdings, Inc. ("HHI") in January 2004, there are currently 8.9 million Class E Units outstanding, all of which are currently owned by HHI. The Class E Units generally do not have any voting rights. The Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. As the Class E Units are owned by a wholly owned subsidiary, the cash distributions on those units are eliminated in our consolidated financial statements. Although no plans are currently in place, management may evaluate whether to retire the Class E Units at a future date.

Class G Units

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

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Class H Units and Class I Units

Currently Outstanding

Pursuant to an Exchange and Redemption Agreement previously entered into between ETP, ETE and ETE Holdings, ETP redeemed and cancelled 50.2 million of its Common Units representing limited partner interests (the "Redeemed Units") owned by ETE Holdings on October 31, 2013 in exchange for the issuance by ETP to ETE Holdings of a new class of limited partner interest in ETP (the "Class H Units"), which are generally entitled to (i) allocations of profits, losses and other items from ETP corresponding to 50.05% of the profits, losses, and other items allocated to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners and (ii) distributions from available cash at ETP for each quarter equal to 50.05% of the cash distributed to ETP by Sunoco Partners with respect to the IDRs and general partner interest in Sunoco Logistics held by Sunoco Partners for such quarter and, to the extent not previously distributed to holders of the Class H Units, for any previous quarters.

Bakken Pipeline Transaction

In March 2015, ETE transferred 30.8 million ETP Common Units, ETE's 45% interest in the Bakken Pipeline project, and $879 million in cash to ETP in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics. In connection with this transaction, ETP also issued 100 Class I Units, as described below, that provide distributions to ETE to offset IDR subsidies previously provided to ETP. These IDR subsidies, including the impact from distributions on Class I Units, were reduced by $55 million in 2015 and $30 million in 2016.

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

General Partner Interest

As of December 31, 2015, our General Partner owned an approximate 0.5% general partner interest in us and the holders of Common Units, Class E, Class G, Class H and Class I Units collectively owned a 99.5% limited partner interest in us.

Incentive Distribution Rights

IDRs represent the contractual right, pursuant to the terms of our partnership agreement, of our general partner to receive a specified percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read "Distributions of Available Cash from Operating Surplus" below.

Cash Distribution Policy

General. We will distribute all of our "Available Cash" to our Unitholders and our General Partner within 45 days following the end of each fiscal quarter.

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;
- comply with applicable law and/or debt instrument or other agreement (including reserves for future capital expenditures and for our future capital needs); or
- provide funds for distributions to Unitholders and our General Partner in respect of any one or more of the next four quarters.

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- 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.

Operating Surplus and Capital Surplus

General. All cash distributed to our Unitholders is characterized as either "operating surplus" or "capital surplus." We distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus. Our operating surplus for any period generally means:

- our cash balance on the closing date of our initial public offering in 1996; plus
- $10 million (as described below); plus
- all of our cash receipts since the closing of our initial public offering, excluding cash from interim capital transactions such as borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus
- our working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; less
- all of our operating expenditures after the closing of our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less
- the amount of our cash reserves that our General Partner deems necessary or advisable to provide funds for future operating expenditures.

Definition of Capital Surplus. Generally, our capital surplus will be generated only by:

- borrowings other than working capital borrowings;
- sales of our debt and equity securities; and
- sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterization of Cash Distributions. We will treat all Available Cash distributed as coming from operating surplus until the sum of all Available Cash distributed since we began operations equals the operating surplus as of the most recent date of determination of Available Cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As defined in our Partnership Agreement, operating surplus includes $10 million in addition to our cash balance on the closing date of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand that is available for distribution to our Unitholders. Rather, it is a provision that enables us, if we choose, to distribute as operating surplus up to $10 million of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities, and long-term borrowings, that would otherwise be distributed as capital surplus. We have not made, and we anticipate that we will not make, any distributions from capital surplus.

Distributions of Available Cash from Operating Surplus

The terms of our partnership agreement require that we make cash distributions with respect to each calendar quarter within 45 days following the end of each calendar quarter. For any quarter, we are required to make distributions of Available Cash from operating surplus initially to the Class H Unitholders in an amount equal to 90.05% of all distributions to ETP by Sunoco Partners LLC with respect to the incentive distribution rights and general partner interest in Sunoco Logistics, calculated on a cumulative basis beginning October 31, 2013. We are also required to make incremental cash distributions to the Class H Unitholders in the aggregate amount of $329 million, subject to adjustment, over 15 quarters, commencing with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2017. We are required to make distributions of any remaining Available Cash from operating surplus for any quarter in the following manner:

- First, 100% to all Common Unitholders, Class E Unitholders, Class G Unitholders and the general partner, in accordance with their percentage interests, until each Common Unit has received $0.25 per unit for such quarter (the "minimum quarterly distribution");

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- Second, 100% to all Common Unitholders, Class E Unitholders, Class G Unitholders and the general partner, in accordance with their respective percentage interests, until each Common Unit has received $0.275 per unit for such quarter (the “first target distribution”);
- Third, (i) to the general partner in accordance with its percentage interest, (ii) 13% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.3175 per unit for such quarter (the “second target distribution”);
- Fourth, (i) to the general partner in accordance with its percentage interest, (ii) 23% to the holders of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs, until each Common Unit has received $0.4125 per unit for such quarter (the “third target distribution”); and
- Fifth, thereafter, (i) to the general partner in accordance with its percentage interest, (ii) 48% to the holder of the IDRs, pro rata, and (iii) to all Common Unitholders, Class E Unitholders and Class G Unitholders, pro rata, a percentage equal to 100% less the percentages applicable to the general partner and holders of the IDRs.

The allocation of distributions among the Common, Class E, Class G and Class H Unitholders and the General Partner is based on their respective interests as of the record date for such distributions.

Notwithstanding the foregoing, the distributions on each Class E unit may not exceed $1.41 per year and distributions on each Class G unit may not exceed $3.75 per year. In addition, the distributions to the holders of the incentive distribution rights will not exceed the amount the holders of the incentive distributions rights would otherwise receive if the available cash for distribution were reduced to the extent it constitutes amounts previously distributed with respect to the Class G units.

The incentive distributions described above do not reflect the impact of IDR subsidies previously agreed to by ETE in connection with previous transactions, as described below under “IDR Subsidies.”

Distributions of Available Cash from Capital Surplus

We are required to make distributions of Available Cash from capital surplus initially to the Class H Unitholders in a manner similar to the distributions of Available Cash from operating surplus, as described above. We will make distributions of any remaining Available Cash from capital surplus in the following manner:

- First, to all of our Unitholders and to our General Partner, in accordance with their percentage interests, until we distribute for each Common Unit, an amount of available cash from capital surplus equal to our initial public offering price; and
- Thereafter, we will make all distributions of Available Cash from capital surplus as if they were from operating surplus.

Our Partnership Agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price per Common Unit less any distributions of capital surplus per unit is referred to as the “unrecovered capital.”

If we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust our minimum quarterly distribution; our target cash distribution levels; and our unrecovered capital. For example, if a two-for-one split of our Common Units should occur, our unrecovered capital would be reduced to 50% of the initial level. We will not make any adjustment by reason of our issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted in a manner that causes us to become taxable as a corporation or otherwise subject to additional taxation as an entity for federal, state or local income tax purposes, under the terms of the Partnership Agreement, we can reduce our minimum quarterly distribution and the target cash distribution levels by multiplying the same by one minus the sum of the highest marginal federal corporate income tax rate that could apply and any increase in the effective overall state and local income tax rates.

The total amount of distributions declared is reflected in Note 8 to our consolidated financial statements. All distributions were made from Available Cash from our operating surplus.

IDR Subsidies and Other Distribution Adjustments

As described above, our partnership agreement requires certain incentive distributions to the holders of the IDRs.

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

	Total Year
2016	$137
2017	128
2018	105
2019	95

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

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.

In accordance with GAAP, we have accounted for the ETP Holdco Transaction, whereby ETP obtained control of Southern Union, and the Regency Merger as reorganizations of entities under common control. Accordingly, ETP's consolidated financial statements for the year ended December 31, 2012 reflected retrospective consolidation of Southern Union into ETP beginning March 26, 2012 (the date ETE acquired Southern Union) and the retrospective consolidation of Regency into ETP beginning May 26, 2010 (the date ETE obtained control of Regency).

These changes only impacted interim periods in 2012, and no prior annual amounts have been adjusted for the ETP Holdco Transaction. The Regency Merger impacted all periods presented below.

	Years Ended December 31,				
	2015	2014	2013	2012	2011
Statement of Operations Data:					
Total revenues	$34,292	$55,475	$48,335	$16,964	$8,190
Operating income	2,259	2,443	1,619	1,425	1,279
Income from continuing operations	1,521	1,235	713	1,754	740
Basic income (loss) from continuing operations per Common Unit	(0.09)	1.58	(0.23)	4.93	1.12
Diluted income (loss) from continuing operations per Common Unit	(0.10)	1.58	(0.23)	4.91	1.12
Cash distributions per unit	4.16	3.86	3.61	3.58	3.58
Balance Sheet Data (at period end):					
Total assets	65,173	62,518	49,900	48,394	20,443
Long-term debt, less current maturities	28,553	24,831	19,761	17,599	9,075
Total equity	27,031	25,311	18,694	19,982	9,247
Other Financial Data:					
Capital expenditures:					
Maintenance (accrual basis)	485	444	391	347	156
Growth (accrual basis)	7,682	5,050	2,936	3,186	1,757
Cash paid for acquisitions	804	2,367	1,737	1,364	1,972

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

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

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

Overview

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

- Natural gas operations, including the following:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which we refer to as ETC OLP; and
  - interstate natural gas transportation and storage through ET Interstate and Panhandle. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger, CrossCountry and ET Rover Pipeline LLC. Panhandle is the parent company of the Trunkline and Sea Robin transmission systems. ETP owns a 50% interest in MEP.
- Liquids operations, including NGL transportation, storage and fractionation services primarily through Lone Star.
- Product and crude oil operations, including the following:
  - product and crude oil transportation, terminalling services and acquisition and marketing activities through Sunoco Logistics; and
  - retail marketing of gasoline and middle distillates through Sunoco, Inc.

Recent Developments

Lake Charles LNG

In December 2015, ETP announced that the Lake Charles LNG Project has received approval from the FERC to site, construct and operate a natural gas liquefaction and export facility in Lake Charles, Louisiana. On February 15, 2016, Royal Dutch Shell plc completed its acquisition of BG Group plc. Final investment decisions from Royal Dutch Shell plc and LCL are expected to be made in 2016, with construction to start immediately following an affirmative investment decision and first LNG export anticipated about four years later.

Sunoco LLC to Sunoco LP

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

Susser to Sunoco LP

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

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Sunoco LP to ETE

Effective July 1, 2015, ETE acquired 100% of the membership interests of Sunoco GP, the general partner of Sunoco LP, and all of the IDRs of Sunoco LP from ETP, and in exchange, ETP repurchased from ETE 21 million ETP common units owned by ETE (the “Sunoco LP Exchange”). In connection with ETP’s 2014 acquisition of Susser, ETE agreed to provide ETP a $35 million annual IDR subsidy for 10 years, which terminated upon the closing of ETE’s acquisition of Sunoco GP. In connection with the exchange and repurchase, ETE will provide ETP a $35 million annual IDR subsidy for two years beginning with the quarter ended September 30, 2015. In connection with this transaction, the Partnership deconsolidated Sunoco LP, including goodwill of $1.81 billion and intangible assets of $982 million related to Sunoco LP. The Partnership continues to hold 37.8 million Sunoco LP common units accounted for under the equity method. The results of Sunoco LP’s operations have not been presented as discontinued operations and Sunoco LP’s assets and liabilities have not been presented as held for sale in the Partnership’s consolidated financial statements.

Sunoco, Inc. to Sunoco LP

In November 2015, ETP and Sunoco LP announced ETP’s contribution to Sunoco LP of the remaining 68.42% interest in Sunoco, LLC and 100% interest in the legacy Sunoco, Inc. retail business for $2.23 billion. Sunoco LP will pay ETP $2.03 billion in cash, subject to certain working capital adjustments, and will issue to ETP 5.7 million Sunoco LP common units. The transaction will be effective January 1, 2016, and is expected to close in March 2016.

Regency Merger

On April 30, 2015, a wholly-owned subsidiary of the Partnership merged with Regency, with Regency surviving as a wholly-owned subsidiary of the Partnership (the “Regency Merger”). Each Regency common unit and Class F unit was converted into the right to receive 0.4124 Partnership common units. ETP issued 172.2 million ETP common units to Regency unitholders, including 15.5 million units issued to Partnership subsidiaries. The 1.9 million outstanding Regency series A preferred units were converted into corresponding new Partnership Series A Preferred Units on a one-for-one basis.

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

Bakken Pipeline Transactions

In March 2015, ETE transferred 30.8 million ETP common units, ETE’s 45% interest in the Bakken Pipeline project, and $879 million in cash to the Partnership in exchange for 30.8 million newly issued Class H Units of ETP that, when combined with the 50.2 million previously issued Class H Units, generally entitle ETE to receive 90.05% of the cash distributions and other economic attributes of the general partner interest and IDRs of Sunoco Logistics. In connection with this transaction, the Partnership also issued to ETE 100 Class I Units that provide distributions to ETE to offset IDR subsidies previously provided to ETP. These IDR subsidies, including the impact from distributions on Class I Units, were reduced by $55 million in 2015 and $30 million in 2016.

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

General

Our primary objective is to increase the level of our distributable cash flow to our Unitholders over time by pursuing a business strategy that is currently focused on growing our businesses through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain strategic operations and businesses or assets as demonstrated by our recent acquisitions and organic growth projects. The actual

amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.
During the past several years, we have been successful in completing several transactions that have significantly increased our distributable cash flow. We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will

provide additional distributable cash flow to our Partnership for years to come. Lastly, we have established and executed on cost control measures to drive cost savings across our operations to generate additional distributable cash flow.

Our principal operations as of December 31, 2015 included the following segments:

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

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

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

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

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

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

In addition to fee-based contracts for gathering, treating and processing, we also have percent-of-proceeds and keep-whole contracts, which are subject to market pricing. For percent-of-proceeds contracts, we retain a portion of the natural gas and

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

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

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

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

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

- Investment in Sunoco Logistics – Revenues are generated by charging tariffs for transporting crude oil, NGLs and refined products through Sunoco Logistics' pipelines as well as by charging fees for terminalling services for crude oil, NGLs and refined products at its facilities. Revenues are also generated by acquiring and marketing crude oil, NGLs and refined products. Generally, crude oil, NGLs and refined products purchases are entered into in contemplation of or simultaneously with corresponding sale transactions involving physical deliveries, which enables us to secure a profit on the transaction at the time of purchase.
- Retail marketing – Revenue is principally generated from the sale of gasoline and middle distillates and the operation of convenience stores in 14 states, primarily on the east coast and in the southern regions of the United States. These

stores complement sales of fuel products with a broad mix of merchandise such as groceries, fast foods, beverages and tobacco products.

Trends and Outlook

We continue to evaluate and execute strategies to enhance unitholder value through growth, as well as the integration and optimization of our diversified asset portfolio. We intend to continue our goal of maintaining a distribution coverage ratio of 1.05x, thereby promoting a prudent balance between distribution rate increases and enhanced financial flexibility and strength while maintaining our investment grade ratings. While we anticipate significant earnings growth in 2017 from the completion of our fully-contracted project backlog, we are currently experiencing the impacts of recent declines in commodity prices, as well as challenging conditions in the capital markets.

The current constraints in the capital markets affect our ability to obtain funding through new borrowings or the issuance of Common Units. In addition, we expect that, to the extent we arrange new financing, we will incur increased costs. In light of the current market conditions, we have taken steps to preserve our liquidity position, including, but not limited to, reducing discretionary capital expenditures, maintaining our cash distribution rate and continuing to manage operating and administrative costs to improve profitability. With the expected closing of the previously announced dropdown of the remaining interest in Sunoco, LLC and the legacy Sunoco retail business to Sunoco LP in late February, the outstanding balance of ETP's $3.75 billion revolver will be close to zero. As a result, ETP does not expect the need to access the fixed income market in 2016. In addition, with our reduction in discretionary capital expenditures and with other related asset sales, we do not anticipate the need for ETP common equity issuances in 2016.

Current market conditions also indicate that many of our customers may encounter increased credit risk in the near term. In particular, our transportation and midstream revenues are derived significantly from companies that engage in exploration and production activities. Many of our customers have been negatively impacted by the recent declines in commodity prices, as well as current conditions in the capital markets. We continue to evaluate the financial condition of existing counterparties, monitor agency credit ratings, and implement credit practices that limit exposure according to the risk profiles of our counterparties.

With respect to commodity prices, crude oil and NGL prices have declined sharply and are at decade-long lows, and we expect prices to remain challenged for the foreseeable future due to general oversupply. The addition of several ethane crackers and export projects (Marcus Hook and Nederland) currently under construction should help to volumetrically balance this market by 2018. Other factors such as reduced wet gas extraction will also help to balance this market and positively impact prices. Natural gas pricing is expected to remain within a range similar to recent history as increased supply continues to outpace demand. New demand has occurred in several areas such as exports to Mexico and Canada, LNG exports, nuclear power plant de-commissioning, as well as continued coal to gas switching for power generation, will help pricing; however, supply is continuing to increase. Exports to Mexico are expected to exceed 2 Bcf/d by the end of 2016, compared to zero in 2014.

We believe that we are well-positioned to benefit from changes in natural gas and NGL supply and demand fundamentals. While we continue to increase our presence in domestic producing basins, we have also recently focused on projects that will position the Partnership as a leader in the export of hydrocarbons. In particular, we currently are undertaking projects involving natural gas exports, including the Rover pipeline project (to Canada), the Trans-Pecos and Comanche Trail pipelines (to Mexico), and waterborne NGL exports, as well as our participation in the Lake Charles LNG liquefaction project. We are also developing the Bakken pipeline project to transport crude supply from the Bakken/Three Forks production area.

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 intend to continue to maintain sufficient liquidity to allow us to fund such potential growth projects and acquisitions.

Results of Operations

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership's proportionate ownership.

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

In accordance with GAAP, we have accounted for the Regency Merger as a reorganization of entities under common control. Accordingly, ETP's consolidated financial statements reflect the retrospective consolidation of Regency into ETP beginning May 26, 2010 (the date ETE obtained control of Regency).

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

	Years Ended December 31,		
	2015	2014	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$543	$559	$(16)
Interstate transportation and storage	1,155	1,212	(57)
Midstream	1,250	1,318	(68)
Liquids transportation and services	731	591	140
Investment in Sunoco Logistics	1,153	971	182
Retail marketing	583	731	(148)
All other	299	328	(29)
Total	5,714	5,710	4
Depreciation, depletion and amortization	(1,929)	(1,669)	(260)
Interest expense, net of interest capitalized	(1,291)	(1,165)	(126)
Gain on sale of AmeriGas common units	—	177	(177)
Impairment losses	(339)	(370)	31
Losses on interest rate derivatives	(18)	(157)	139
Non-cash compensation expense	(79)	(68)	(11)
Unrealized gains (losses) on commodity risk management activities	(65)	112	(177)
Inventory valuation adjustments	(104)	(473)	369
Losses on extinguishments of debt	(43)	(25)	(18)
Adjusted EBITDA related to discontinued operations	—	(27)	27
Adjusted EBITDA related to unconsolidated affiliates	(937)	(748)	(189)
Equity in earnings of unconsolidated affiliates	469	332	137
Other, net	20	(36)	56
Income from continuing operations before income tax expense	1,398	1,593	(195)
Income tax (expense) benefit from continuing operations	123	(358)	481
Income from continuing operations	1,521	1,235	286
Income from discontinued operations	—	64	(64)
Net income	$1,521	$1,299	$222

See the detailed discussion of Segment Adjusted EBITDA below.

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

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

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

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was recorded related to the Permian Basin gathering and processing operations. The decline in estimated fair value of that reporting unit was primarily driven by a significant decline in commodity prices in the fourth quarter of 2014, and the resulting impact to future commodity prices as well as increases in future estimated operations and maintenance expenses.

Losses on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Losses on interest rate derivatives during the years ended December 31, 2015 and 2014 resulted from decreases in forward interest rates, which caused our forward-starting swaps to decrease in value.

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

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

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

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

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

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

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31,		
	2015	2014	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$97	$96	$1
FEP	55	55	—
PES	52	59	(7)
MEP	45	45	—
HPC	32	28	4
AmeriGas	(3)	21	(24)
Sunoco, LLC	(10)	—	(10)
Sunoco LP	202	—	202
Other	(1)	28	(29)
Total equity in earnings of unconsolidated affiliates	$469	$332	$137
Adjusted EBITDA related to unconsolidated affiliates[1]:			
Citrus	$315	$305	$10
FEP	75	75	—
PES	86	86	—
MEP	96	102	(6)
HPC	61	53	8
AmeriGas	—	56	(56)
Sunoco, LLC	91	—	91
Sunoco LP	137	—	137
Other	76	71	5
Total Adjusted EBITDA related to unconsolidated affiliates	$937	$748	$189
Distributions received from unconsolidated affiliates:			
Citrus	$182	$168	$14
FEP	69	70	(1)
PES	78	—	78
MEP	80	73	7
HPC	52	48	4
AmeriGas	—	22	(22)
Sunoco LP	39	—	39
Other	53	40	13
Total distributions received from unconsolidated affiliates	$553	$421	$132

(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

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

In 2014, certain costs previously reported as selling, general and administrative expenses were reclassified to operating expenses. These costs include support functions such as engineering, environmental services, maintenance and reliability, pipeline integrity, procurement and technical services. Prior period amounts have been reclassified to conform to the current year presentation.

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:

- Gross 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 gross margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.
- Non-cash compensation expense. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative expenses. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.
- Adjusted EBITDA related to unconsolidated affiliates. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA.

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

Intrastate Transportation and Storage

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

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

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

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

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

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

Storage margin was comprised of the following:

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

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

Interstate Transportation and Storage

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

Volumes. For the year ended December 31, 2015 compared to the prior year, transported volumes decreased 165,712 MMBtu/d on the Trunkline pipeline, primarily due to a managed contract roll off to facilitate the transfer of one of the pipelines that was taken out of service in advance of being repurposed from natural gas service to crude oil service. The decrease on the Trunkline pipeline was partially offset by an increase in volumes transported on the Tiger pipeline of 74,081 MMBtu/d, primarily due to

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increased deliveries to pipelines supporting the upper Midwest due to favorable market conditions and increased volumes on the Transwestern pipeline of 69,237 MMBtu/d due to sustained cooling demand in the Phoenix market and increased customer demand in the Texas intrastate market.

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

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

Midstream

	Years Ended December 31,		
	2015	2014	Change
Gathered volumes (MMBtu/d)	9,981,217	8,079,109	1,902,108
NGLs produced (Bbls/d)	406,282	317,502	88,780
Equity NGLs (Bbls/d)	28,493	27,611	882
Revenues	$5,071	$6,823	$(1,752)
Cost of products sold	3,266	4,893	(1,627)
Gross margin	1,805	1,930	(125)
Unrealized (gains) losses on commodity risk management activities	82	(89)	171
Operating expenses, excluding non-cash compensation expense	(616)	(481)	(135)
Selling, general and administrative expenses, excluding non-cash compensation expense	(44)	(54)	10
Adjusted EBITDA related to unconsolidated affiliates	20	12	8
Other	3	—	3
Segment Adjusted EBITDA	$1,250	$1,318	$(68)

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

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

	Years Ended December 31,		
	2015	2014	Change
Gathering and processing fee-based revenues	$1,547	$1,278	$269
Non fee-based contracts and processing	258	652	(394)
Total gross margin	$1,805	$1,930	$(125)

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

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

Liquids Transportation and Services

	Years Ended December 31,		
	2015	2014	Change
Liquids transportation volumes (Bbls/d)	437,226	335,140	102,086
NGL fractionation volumes (Bbls/d)	235,800	189,931	45,869
Revenues	$3,481	$3,911	$(430)
Cost of products sold	2,595	3,166	(571)
Gross margin	886	745	141
Unrealized (gains) losses on commodity risk management activities	6	(12)	18
Operating expenses, excluding non-cash compensation expense	(152)	(128)	(24)
Selling, general and administrative expenses, excluding non-cash compensation expense	(16)	(20)	4
Adjusted EBITDA related to unconsolidated affiliates	7	6	1
Segment Adjusted EBITDA	$731	$591	$140

Volumes. The increase in liquids transportation volumes for the year ended December 31, 2015 compared to the prior year reflected an increase of approximately 71,000 Bbls/d on our NGL pipelines. For the year ended December 31, 2015, we experienced increases in volumes from the Eagle Ford, Permian, and Southeast Texas producing regions, offset by lower volumes from North Texas. Additionally, we commissioned a crude transportation pipeline in the fourth quarter of 2014 that transported approximately 39,000 Bbls/d for the year ended December 31, 2015 as compared to 8,000 Bbls/d in the prior year.

Average daily fractionated volumes increased approximately 46,000 Bbls/d for the year ended December 31, 2015 compared to the prior year primarily due to the ramp-up of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas, which was commissioned in October 2013. These volumes include all physical and contractual volumes where we collected a fee.

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

	Years Ended December 31,		
	2015	2014	Change
Transportation margin	$381	$312	$69
Processing and fractionation margin	297	247	50
Storage margin	172	157	15
Other margin	36	29	7
Total gross margin	$886	$745	$141

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

- an increase of $69 million in transportation margin primarily due to higher volumes transported out of West Texas and the Eagle Ford producing regions. Increased volumes out of West Texas led to $47 million in additional transportation fees, while increased volumes from the Eagle Ford region led to $15 million in additional transportation fees for the year ended December 31, 2015. We also realized an increase of $7 million for the year ended December 31, 2015 from our crude pipeline, which was commissioned in the fourth quarter of 2014;
- an increase of $42 million in processing and fractionation margin (excluding changes in unrealized gains of $8 million) due to $9 million increase in margin from our fractionators due to the ramp-up of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas, and the additional volumes from producers in West Texas and the Eagle Ford regions offset by reductions in blending gains due to lower market prices. Additionally, the commissioning of the Mariner South LPG export project during February 2015 contributed an additional $50 million for the twelve months ended December 31, 2015. Margin associated with our off-gas fractionator in Geismar, Louisiana decreased by $17 million for the year ended December 31, 2015 as NGL and olefin market prices decreased significantly for the comparable period;
- an increase of $15 million in storage margin due to a $24 million increase in fee based storage margin for year ended December 31, 2015 from an increase in demand for leased storage capacity as a result of favorable market conditions and a specific contract negotiated in connection with the Mariner South LPG export project. The increase in fee based storage margin was offset by lower non-fee based margin of $8 million for the year ended December 31, 2015 primarily due to lower propane blending gains;
- an increase of $33 million in other margin (excluding changes in unrealized losses of $26 million) primarily due to the withdrawal and sale of physical storage volumes, primarily propane and butanes; and
- a decrease of $4 million in selling, general and administrative expenses primarily due to lower employee-related costs; partially offset by
- an increase of $24 million in operating expenses primarily due to a $6 million increase in employee expenses, a $4 million increase in ad valorem taxes, a $3 million increase in utilities expense, a $6 million increase in project costs and materials and supplies expense, and a $5 million increase in overhead expense allocations.

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Investment in Sunoco Logistics

	Years Ended December 31,		
	2015	2014	Change
Revenue	$10,486	$18,088	$(7,602)
Cost of products sold	9,307	17,135	(7,828)
Gross margin	1,179	953	226
Unrealized (gains) losses on commodity risk management activities	4	(17)	21
Operating expenses, excluding non-cash compensation expense	(158)	(167)	9
Selling, general and administrative expenses, excluding non-cash compensation expense	(92)	(107)	15
Inventory valuation adjustments	162	258	(96)
Adjusted EBITDA related to unconsolidated affiliates	58	49	9
Other	—	2	(2)
Segment Adjusted EBITDA	$1,153	$971	$182

Segment Adjusted EBITDA. For the year ended December 31, 2015 compared to the prior year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- an increase of $130 million from Sunoco Logistics’ NGLs operations, primarily due to contributions from Sunoco Logistics’ Mariner NGLs projects which commenced operations in late 2014 and 2013. These projects contributed to improved results related to Sunoco Logistics’ NGLs pipeline and terminal operations of $160 million, including Sunoco Logistics’ Nederland and Marcus Hook facilities. These positive impacts were partially offset by lower results from Sunoco Logistics’ NGLs acquisition and marketing activities of $33 million driven largely by narrowed blending margins compared to the prior year period; and
- an increase of $65 million from Sunoco Logistics’ refined products operations, primarily due to higher results from Sunoco Logistics’ refined products pipelines of $33 million driven largely by the commencement of operations on Sunoco Logistics’ Allegheny Access project in 2015. Terminalling activities at Sunoco Logistics’ refined products marketing terminals, as well as Sunoco Logistics’ Eagle Point and Marcus Hook facilities, increased compared to the prior year period by $15 million. Higher contributions from Sunoco Logistics’ joint venture interests of $10 million and refined products acquisition and marketing activities of $6 million also contributed to the increase; offset by
- a decrease of $13 million from Sunoco Logistics’ crude oil operations, primarily due to lower results from Sunoco Logistics’ crude oil acquisition and marketing activities of $96 million driven by reduced margins which were negatively impacted by contracted crude oil differentials compared to the prior year period. This impact was partially offset by higher results from Sunoco Logistics’ crude oil pipelines of $71 million largely attributable to expansion projects placed into service in 2015 and 2014, and higher results from Sunoco Logistics’ crude oil terminals of $14 million.

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Retail Marketing

	Years Ended December 31,		
	2015	2014	Change
Motor fuel outlets and convenience stores, end of period:			
Retail	438	1,251	(813)
Third-party wholesale	—	5,399	(5,399)
Total	438	6,650	(6,212)
Total motor fuel gallons sold (in millions):			
Retail	1,884	1,646	238
Third-party wholesale	2,592	4,736	(2,144)
Total	4,476	6,382	(1,906)
Motor fuel gross profit (cents/gallon):			
Retail	22.2	31.2	(9.0)
Third-party wholesale	10.5	9.4	1.1
Volume-weighted average for all gallons	15.4	15.0	0.4
Merchandise sales (in millions)	$1,365	$1,091	$274
Retail merchandise margin %	30.7 %	28.6 %	2.1 %
Revenue	$12,482	$22,487	$(10,005)
Cost of products sold	11,174	21,154	(9,980)
Gross margin	1,308	1,333	(25)
Unrealized (gains) losses on commodity risk management activities	2	(1)	3
Operating expenses, excluding non-cash compensation expense	(796)	(727)	(69)
Selling, general and administrative expenses, excluding non-cash compensation expense	(103)	(92)	(11)
Inventory valuation adjustments	(58)	215	(273)
Adjusted EBITDA related to unconsolidated affiliates	230	3	227
Segment Adjusted EBITDA	$583	$731	$(148)

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

- a decrease of $124 million due to the deconsolidation of Sunoco LP as a result of the sale of Sunoco LP's general partner interest and incentive distribution rights to ETE effective July 1, 2015;
- a decrease of $121 million due to unfavorable fuel margins and $9 million due to unfavorable volumes in the retail and wholesale channels; and
- a decrease of $49 million in margins as 2014 benefited from favorable regional market conditions for ethanol; partially offset by
- the favorable impact of $112 million from the acquisition of Susser in August 2014 until its contribution to Sunoco LP in July 2015 and $43 million from other recent acquisitions.

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All Other

	Years Ended December 31,		
	2015	2014	Change
Revenue	$3,292	$3,331	$(39)
Cost of products sold	2,855	2,975	(120)
Gross margin	437	356	81
Unrealized gains on commodity risk management activities	(3)	(14)	11
Operating expenses, excluding non-cash compensation expense	(93)	(106)	13
Selling, general and administrative expenses, excluding non-cash compensation expense	(138)	(146)	8
Adjusted EBITDA related to discontinued operations	—	27	(27)
Adjusted EBITDA related to unconsolidated affiliates	83	146	(63)
Other	75	73	2
Elimination	(62)	(8)	(54)
Segment Adjusted EBITDA	$299	$328	$(29)

Amounts reflected in our all other segment primarily include:

- our natural gas marketing and compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture;
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities; and
- our investment in AmeriGas until August 2014.

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

- a decrease of $63 million in Adjusted EBITDA related to unconsolidated affiliates, primarily due to a decrease of $56 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2014; and
- a decrease in Adjusted EBITDA related to discontinued operations of $27 million in the prior period related to a marketing business that was sold effective April 1, 2014; offset by
- an increase of $21 million related to our contract services operations primarily due to an increase in revenue-generating horsepower; and
- an increase of $17 million related to our natural resources operations, for which the period reflected only a partial period due to the acquisition of those operations in March 2014.

In connection with the Lake Charles LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2015 and 2014. These fees were reflected in "Other" in the "All other" segment and for the years ended December 31, 2015 and 2014 were reflected as an offset to operating expenses of $25 million and selling, general and administrative expenses of $50 million in the consolidated statements of operations.

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

Consolidated Results

	Years Ended December 31,		
	2014	2013	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$559	$521	$38
Interstate transportation and storage	1,212	1,368	(156)
Midstream	1,318	757	561
Liquids transportation and services	591	350	241
Investment in Sunoco Logistics	971	871	100
Retail marketing	731	325	406
All other	328	212	116
Total	5,710	4,404	1,306
Depreciation, depletion and amortization	(1,669)	(1,296)	(373)
Interest expense, net of interest capitalized	(1,165)	(1,013)	(152)
Gain on sale of AmeriGas common units	177	87	90
Impairment losses	(370)	(689)	319
Gains (losses) on interest rate derivatives	(157)	44	(201)
Non-cash compensation expense	(68)	(54)	(14)
Unrealized gains on commodity risk management activities	112	42	70
Inventory valuation adjustments	(473)	3	(476)
Losses on extinguishments of debt	(25)	(7)	(18)
Non-operating environmental remediation	—	(168)	168
Adjusted EBITDA related to discontinued operations	(27)	(76)	49
Adjusted EBITDA related to unconsolidated affiliates	(748)	(722)	(26)
Equity in earnings of unconsolidated affiliates	332	236	96
Other, net	(36)	19	(55)
Income from continuing operations before income tax expense	1,593	810	783
Income tax expense from continuing operations	(358)	(97)	(261)
Income from continuing operations	1,235	713	522
Income from discontinued operations	64	33	31
Net income	$1,299	$746	$553

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions, including Regency's acquisitions in 2014, partially offset by a decrease in depreciation and amortization of $39 million related to the Lake Charles LNG Transaction.

Gain on Sale of AmeriGas Common Units. During the year ended December 31, 2014 and 2013, we sold 18.9 million and 7.5 million, respectively, of the AmeriGas common units that were originally received in connection with the contribution of our propane business to AmeriGas in January 2012. We recorded a gain based on the sale proceeds in excess of the carrying amount of the units sold. As of December 31, 2014, the Partnership's remaining interest in AmeriGas common units consisted of 3.1 million units held by a wholly-owned captive insurance company.

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

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

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

Unrealized Gains on Commodity Risk Management Activities. See discussion of the unrealized gains on commodity risk management activities included in "Segment Operating Results" below.

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

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

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

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

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

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

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2014	2013	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$96	$87	$9
FEP	55	55	—
PES	59	(48)	107
MEP	45	40	5
HPC	28	30	(2)
AmeriGas	21	50	(29)
Other	28	22	6
Total equity in earnings of unconsolidated affiliates	$332	$236	$96
Adjusted EBITDA related to unconsolidated affiliates[1]:			
Citrus	$305	$296	$9
FEP	75	75	—
PES	86	(30)	116
MEP	102	100	2
HPC	53	51	2
AmeriGas	56	175	(119)
Other	71	55	16
Total Adjusted EBITDA related to unconsolidated affiliates	$748	$722	$26
Distributions received from unconsolidated affiliates:			
Citrus	$168	$175	$(7)
FEP	70	69	1
PES	—	65	(65)
MEP	73	72	1
HPC	48	238	(190)
AmeriGas	22	86	(64)
Other	40	27	13
Total distributions received from unconsolidated affiliates	$421	$732	$(311)

(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.

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Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2014	2013	Change
Natural gas transported (MMBtu/d)	8,976,978	9,455,878	(478,900)
Revenues	$2,857	$2,452	$405
Cost of products sold	2,169	1,737	432
Gross margin	688	715	(27)
Unrealized (gains) losses on commodity risk management activities	21	(39)	60
Operating expenses, excluding non-cash compensation expense	(180)	(188)	8
Selling, general and administrative, excluding non-cash compensation expense	(27)	(24)	(3)
Adjusted EBITDA related to unconsolidated affiliates	57	57	—
Segment Adjusted EBITDA	$559	$521	$38

Volumes. Transported volumes decreased due to the reduction of volumes under certain long-term transportation contracts offset by increased volumes due to a more favorable pricing environment.

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

	Years Ended December 31,		
	2014	2013	Change
Transportation fees	$466	$491	$(25)
Natural gas sales and other	100	80	20
Retained fuel revenues	98	96	2
Storage margin, including fees	24	48	(24)
Total gross margin	$688	$715	$(27)

Segment Adjusted EBITDA. For the year ended December 31, 2014 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 $31 million in storage margin (excluding changes in unrealized losses of $55 million), as discussed below;
- an increase of $23 million in natural gas sales and other margin (excluding changes in unrealized losses of $3 million) primarily due to favorable results from our optimization activities. Margin from natural gas sales and other includes purchased natural gas for transport and sale, derivatives used to hedge transportation activities, gains and losses on derivatives used to hedge net retained fuel, and the margin from gas sales, processing and gathering fees on our Houston pipeline system;
- a decrease of $8 million in operating expenses primarily due to a decrease in ad valorem taxes driven by the settlement of lower valuation with local taxing authorities during the period; and
- an increase of $2 million in retention revenue as gains due to increased market prices, resulting in an $11 million increase in retention gas sales, were offset by a reduction of $9 million due to lower volumes resulting from the cessation of certain long-term contracts. The average spot price at the Houston Ship Channel location for the year ended December 31, 2014 increased by $0.62/MMBtu, or 17%, to $4.31/MMBtu compared to $3.69/MMBtu in the prior year. Retained fuel volumes were down 9% from year to year; partially offset by
- a decrease of $25 million in transportation fees margin primarily due to the reduction of volumes under certain long-term transportation contracts; and
- an increase of $3 million in selling, general and administrative expenses primarily due to higher employee-related costs.

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Storage margin was comprised of the following:

	Years Ended December 31,		
	2014	2013	Change
Withdrawals from storage natural gas inventory (MMBtu)	37,197,510	36,962,300	235,210
Realized margin on natural gas inventory transactions	$17	$(16)	$33
Fair value inventory adjustments	(54)	28	(82)
Unrealized gains on derivatives	35	8	27
Margin recognized on natural gas inventory, including related derivatives	(2)	20	(22)
Revenues from fee-based storage	27	28	(1)
Other costs	(1)	—	(1)
Total storage margin	$24	$48	$(24)

The decrease in storage margin was principally driven by a decline in the spreads between the spot and forward prices on natural gas we own in the Bammel storage facility resulting in a $14 million reduction in margin from year to year. The remainder of the decrease was primarily due to non-cash mark-to-market losses of $8 million on hedges for future storage seasons.

Interstate Transportation and Storage

	Years Ended December 31,		
	2014	2013	Change
Natural gas transported (MMBtu/d)	6,159,546	6,480,215	(320,669)
Natural gas sold (MMBtu/d)	16,470	18,835	(2,365)
Revenues	$1,072	$1,309	$(237)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(291)	(332)	41
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(62)	(80)	18
Adjusted EBITDA related to unconsolidated affiliates	482	471	11
Other	11	—	11
Segment Adjusted EBITDA	$1,212	$1,368	$(156)

Volumes. For the year ended December 31, 2014 compared to the prior year, transported volumes decreased due to lower volumes transported on the Tiger pipeline resulting from decreased production from the Haynesville Shale and due to lower utilization on the Trunkline and Transwestern pipelines. The decreases in volumes on the Tiger, Trunkline and Transwestern pipelines were partially offset by higher volumes transported on the Panhandle pipeline due to increased demand resulting from the cold winter season during the first quarter of 2014.

Segment Adjusted EBITDA. For the year ended December 31, 2014 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $216 million in revenues from the deconsolidation of Lake Charles LNG effective January 1, 2014 and the recognition in 2013 of $52 million received in connection with the buyout of a customer contract. These revenue decreases were partially offset by an increase of approximately $29 million due to capacity sold at higher rates and gas parking service revenues from higher basis differentials and spot prices resulting from the colder weather, primarily during the first quarter of 2014 on the Panhandle pipeline; partially offset by
- a decrease $41 million in operating expenses primarily due to the deconsolidation of Lake Charles LNG effective January 1, 2014;
- a decrease of $18 million in selling, general and administrative expenses due to a decrease of $9 million from the deconsolidation of Lake Charles LNG, a decrease of $7 million in professional fees, and a decrease of $2 million in employee-related costs;

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- an increase of $11 million in adjusted EBITDA related to unconsolidated affiliates primarily due to increased earnings from Citrus as a result of the sale of additional capacity and lower operating expenses due to lower ad valorem taxes; and
- an increase of $11 million due to the recognition of an $11 million keep-whole payment received from our FEP joint venture partner.

Midstream

	Years Ended December 31,		
	2014	2013	Change
Gathered volumes (MMBtu/d):	7,780,278	4,609,359	3,170,919
NGLs produced (Bbls/d):	317,487	198,894	118,593
Equity NGLs (Bbls/d):	27,611	19,340	8,271
Revenues	$6,823	$4,276	$2,547
Cost of products sold	4,893	3,130	1,763
Gross margin	1,930	1,146	784
Unrealized (gains) losses on commodity risk management activities	(89)	2	(91)
Operating expenses, excluding non-cash compensation expense	(481)	(358)	(123)
Selling, general and administrative, excluding non-cash compensation expense	(54)	(38)	(16)
Adjusted EBITDA related to unconsolidated affiliates	12	3	9
Other	—	2	(2)
Segment Adjusted EBITDA	$1,318	$757	$561

Volumes. Gathered volumes, NGL produced and equity NGLs increased for the year ended December 31, 2014 compared to the prior year primarily due to increased production by our customers in the Eagle Ford Shale and the Permian Basin. We brought into service 320 MMcf/d in additional processing capacity during the year ended December 31, 2014.

Segment Adjusted EBITDA. For the year ended December 31, 2014 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 $669 million in gross margin related to Regency's gathering and processing operations, primarily due to Regency's acquisitions of PVR, Eagle Rock midstream assets and Hoover in 2014, and an increase in fee-based revenues of $121 million from ETP's legacy midstream assets due to increased production and increased capacity from assets recently placed in service in the Eagle Ford Shale; and
- an increase of $9 million in adjusted EBITDA related to unconsolidated affiliates primarily due to increased throughput and condensate sales related to Regency's investment in Ranch JV; partially offset by
- an increase in midstream operating expenses primarily due to a $76 million increase in pipeline and plant maintenance and materials due to organic growth on Regency's assets in south and West Texas, as well as increased employee-related costs from Regency's acquisitions of PVR, Eagle Rock midstream assets and Hoover in 2014.

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Liquids Transportation and Services

	Years Ended December 31,		
	2014	2013	Change
Liquids transportation volumes (Bbls/d)	335,140	172,569	162,571
NGL fractionation volumes (Bbls/d)	189,931	17,754	172,177
Revenues	$3,911	$2,126	$1,785
Cost of products sold	3,166	1,654	1,512
Gross margin	745	472	273
Unrealized gains on commodity risk management activities	(12)	(1)	(11)
Operating expenses, excluding non-cash compensation expense	(128)	(110)	(18)
Selling, general and administrative expenses, excluding non-cash compensation expense	(20)	(16)	(4)
Adjusted EBITDA related to unconsolidated affiliates	6	5	1
Segment Adjusted EBITDA	$591	$350	$241

Volumes. The increase in liquids transportation volumes for the year ended December 31, 2014 compared to the prior year reflected an increase of approximately 109,000 Bbls/d in volumes transported on our wholly-owned and joint venture NGL pipelines due to an increase in production for our Jackson processing plant and volumes transported to our Mont Belvieu, Texas facilities via our Justice pipeline. The remainder of the increase was from volumes transported on our Lone Star pipeline system primarily out of West Texas.

Average daily fractionated volumes increased for the year ended December 31, 2014 compared to the prior year primarily due to the recent commissioning of our second 100,000 Bbls/d fractionator at Mont Belvieu, Texas. These volumes include all physical and contractual volumes where we collected a fractionation fee.

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

	Years Ended December 31,		
	2014	2013	Change
Transportation margin	$312	$187	$125
Processing and fractionation margin	247	142	105
Storage margin	157	137	20
Other margin	29	6	23
Total gross margin	$745	$472	$273

Segment Adjusted EBITDA. For the year ended December 31, 2014 compared to the prior year, Segment Adjusted EBITDA related to our liquids transportation and services segment increased due to the net impacts of the following:

- an increase of $69 million in transportation margin due to higher volumes transported from West Texas and the Eagle Ford Shale on our Lone Star pipeline system and a $56 million increase due to in NGL production from our processing plants that connect to various fractionators via our wholly-owned pipelines;
- an increase of $117 million in processing and fractionation margin due to the startup of Lone Star’s second fractionator at Mont Belvieu, Texas in October 2013. This increase was partially offset by a $12 million decrease in margin attributable to our fractionator in Geismar, Louisiana, where margin was affected by the combined impacts from a less rich refinery off-gas feed and lower overall production volumes through the facility following the expiration of a major supplier contract in June 2013;
- an increase of $13 million in storage margin due to increased throughput activity. The remainder of the increase in storage margin was primarily due to increased blending and other non fee-based storage activities; and
- an increase of $12 million in other margin (excluding changes in unrealized gains of $11 million) due to increased commercial optimization activities related to our fractionators, primarily due to the recent commissioning of our second fractionator at Mont Belvieu, Texas and the optimization of available storage capacity at our Mont Belvieu facilities; partially offset by

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- an increase of $18 million in operating expenses primarily due to the start-up of Lone Star's second fractionator in Mont Belvieu, Texas in October 2013; and
- an increase of $4 million in selling, general and administrative expenses primarily due to an increase in employee-related costs.

Investment in Sunoco Logistics

	Years Ended December 31,		
	2014	2013	Change
Revenue	$18,088	$16,639	$1,449
Cost of products sold	17,135	15,600	1,535
Gross margin	953	1,039	(86)
Unrealized gains on commodity risk management activities	(17)	(1)	(16)
Operating expenses, excluding non-cash compensation expense	(167)	(122)	(45)
Selling, general and administrative expenses, excluding non-cash compensation expense	(107)	(79)	(28)
Inventory valuation adjustments	258	—	258
Adjusted EBITDA related to unconsolidated affiliates	49	41	8
Other	2	(7)	9
Segment Adjusted EBITDA	$971	$871	$100

Segment Adjusted EBITDA. For the year ended December 31, 2014 compared to the prior year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- an increase of $130 million from Sunoco Logistics' NGLs operations, primarily due to improved results from Sunoco Logistics' NGLs acquisition and marketing activities of $101 million driven by higher volumes which benefited from a full year of results from the Marcus Hook Industrial Complex, increased margins, and favorable inventory timing compared to the prior year period. Higher contributions from Sunoco Logistics' NGLs pipelines of $38 million were largely driven by Sunoco Logistics' Mariner West project which commenced operations in late 2013. NGLs terminalling activities at Sunoco Logistics' Marcus Hook Industrial Complex of $8 million also contributed to the increase. These positive impacts were partially offset by increased selling, general and administrative expenses of $16 million attributable to growth projects; and
- an increase of $2 million from Sunoco Logistics' refined products operations, primarily due to higher contributions from Sunoco Logistics' joint venture interests of $8 million and lower selling, general and administrative expenses of $10 million. These positive impacts were largely offset by lower results from Sunoco Logistics' refined products pipelines $13 million largely driven by reduced throughput volumes and decreased contributions from Sunoco Logistics' refined products terminalling activities of $4 million; offset by
- a decrease of $32 million from Sunoco Logistics' crude oil operations, primarily due to lower results from Sunoco Logistics' crude oil acquisition and marketing activities of $66 million driven by reduced margins which were negatively impacted by contracted crude oil differentials compared to the prior year period. Increased selling, general and administrative expenses attributable to growth projects of $3 million also contributed to the decrease. This impact was partially offset by improved contributions from Sunoco Logistics' crude oil pipelines of $29 million which benefited from expansion projects placed into service in 2014 and 2013, and higher results attributable to crude oil terminal activities of $8 million.

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Retail Marketing

	Years Ended December 31, 2014	2013	Change
Motor fuel outlets and convenience stores, end of period:			
Retail	1,251	513	738
Third-party wholesale	5,399	4,599	800
Total	6,650	5,112	1,538
Total motor fuel gallons sold (in millions):			
Retail	1,646	1,092	554
Third-party wholesale	4,736	4,364	372
Total	$6,382	$5,456	$926
Motor fuel gross profit (cents/gallon):			
Retail	31.2	25.5	5.7
Third-party wholesale	9.4	6.3	3.1
Volume-weighted average for all gallons	15.0	10.1	4.9
Merchandise sales (in millions)	$1,091	$543	$548
Retail merchandise margin %	28.6 %	26.5 %	2.1 %
Revenue	$22,487	$21,012	$1,475
Cost of products sold	21,154	20,150	1,004
Gross margin	1,333	862	471
Unrealized gains on commodity risk management activities	(1)	(1)	—
Operating expenses, excluding non-cash compensation expense	(727)	(473)	(254)
Selling, general and administrative expenses, excluding non-cash compensation expense	(92)	(63)	(29)
Inventory valuation adjustments	215	(3)	218
Adjusted EBITDA related to unconsolidated affiliates	3	4	(1)
Other	—	(1)	1
Segment Adjusted EBITDA	$731	$325	$406

Segment Adjusted EBITDA. For the year ended December 31, 2014 compared to the prior year, Segment Adjusted EBITDA related to our retail marketing segment increased due to the net impacts of the following:

- an increase of $471 million in gross margin due to a favorable impact of $335 million from the acquisition of Susser in August 2014 and $158 million from other recent acquisitions, including the MACS acquisition in October 2013. Retail marketing gross margin also increased $136 million from strong retail gasoline and diesel margins and $60 million due to favorable results in non-retail margins. These increases were partially offset by unfavorable impacts of $218 million related to non-cash inventory valuation adjustments as a result of commodity price changes between periods; partially offset by
- an increase of $254 million in operating expenses primarily due to recent acquisitions; and
- an increase of $29 million in selling, general and administrative expenses primarily due to recent acquisitions.

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All Other

	Years Ended December 31,		
	2014	2013	Change
Revenue	$3,331	$2,597	$734
Cost of products sold	2,975	2,337	638
Gross margin	356	260	96
Unrealized gains on commodity risk management activities	(14)	(2)	(12)
Operating expenses, excluding non-cash compensation expense	(106)	(104)	(2)
Selling, general and administrative expenses, excluding non-cash compensation expense	(146)	(139)	(7)
Adjusted EBITDA related to discontinued operations	27	76	(49)
Adjusted EBITDA related to unconsolidated affiliates	146	147	(1)
Other	73	(2)	75
Elimination	(8)	(24)	16
Segment Adjusted EBITDA	$328	$212	$116

Amounts reflected in our all other segment primarily include:

- our natural gas marketing and compression operations;
- an approximate 33% non-operating interest in PES, a refining joint venture;
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities; and
- our investment in AmeriGas until August 2014.

Segment Adjusted EBITDA. For the year ended December 31, 2014 compared to the prior year, Segment Adjusted EBITDA increased due to the net impact of the following:

- an increase of $75 million in management fees, as further described below;
- an increase of $50 million in gross margin related to Regency's contract service operations due to increased revenue generating horsepower and $58 million related to Regency's natural resources operations due to the acquisition of those assets in March 2014, offset by an increase of $26 million in operating expenses;
- a favorable impact of approximately $47 million due to costs associated with certain Sunoco activities that were included in the all other Segment Adjusted EBITDA in the prior year;
- favorable results and recent acquisitions from our natural gas marketing business of $15 million and $6 million, respectively;
- higher earnings from our investment in PES of $116 million, offset by a decrease of $119 million related to our investment in AmeriGas driven by a reduction in our investment due to the sale of AmeriGas common units in 2014 and 2013;
- a refund of insurance premiums of $6 million included in the year ended December 31, 2014; and
- Southern Union corporate expenses of $14 million that were no longer included in the all other segment subsequent to the merger of Southern Union, PEPL Holdings and Panhandle in January 2014; partially offset by
- an increase of $78 million in selling, general and administrative expenses related to Regency's operations, primarily due to a $33 million increase in acquisition costs, with the remainder primarily attributable to increased employee-related expenses;
- the recognition of $25 million in merger related costs related to the Susser Merger in the year ended December 31, 2014; and
- a decrease in Adjusted EBITDA related to discontinued operations of $49 million primarily due to the sale of Southern Union's local distribution operations in 2013.

In connection with the Lake Charles LNG Transaction, ETP agreed to continue to provide management services for ETE through 2015 in relation to both Lake Charles LNG's regasification facility and the development of a liquefaction project at Lake Charles LNG's facility, for which ETE has agreed to pay incremental management fees to ETP of $75 million per year for the years ending December 31, 2014 and 2015. These fees were reflected in "Other" in the "All other" segment and for the year ended December 31, 2014 were reflected as an offset to operating expenses of $25 million and selling, general and administrative expenses of $50 million in the consolidated statements of operations.

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Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our 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.

We currently expect the following capital expenditures in 2016 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Direct[(1)]:				
Intrastate transportation and storage[(2)]	$10	$20	$35	$40
Interstate transportation and storage[(2)(3)]	375	415	140	145
Midstream	1,200	1,250	110	120
Liquids transportation and services				
NGL	1,150	1,200	25	30
Crude[(3)]	1,275	1,325	—	—
All other (including eliminations)	65	75	20	25
Total direct capital expenditures	$4,075	$4,285	$330	$360

(1) Direct capital expenditures exclude those funded by our publicly traded subsidiary.

(2) Net of amounts forecasted to be financed at the asset level with non-recourse debt of approximately $325 million.

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

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

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

As of December 31, 2015, in addition to $527 million of cash on hand, we had available capacity under the ETP Credit Facility of $2.24 billion. Based on our current estimates, we expect to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs through the end of 2016; 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 Logistics' primary sources of liquidity consist of cash generated from operating activities and borrowings under its $2.50 billion credit facility. At December 31, 2015, Sunoco Logistics had available borrowing capacity of $1.94 billion under its revolving credit facility. Sunoco Logistics' capital position reflects crude oil and refined products inventories based on historical costs under the last-in, first-out ("LIFO") method of accounting. Sunoco Logistics periodically supplements its cash flows from operations with proceeds from debt and equity financing activities.

Cash Flows

Our internally generated 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 for 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 unit-based compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when 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 purchase 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, 2015
Cash provided by operating activities in 2015 was $2.75 billion and net income was $1.52 billion. The difference between net income and cash provided by operating activities in 2015 primarily consisted of non-cash items totaling $2.17 billion offset by net changes in operating assets and liabilities of $1.37 billion. The non-cash activity in 2015 consisted primarily of depreciation, depletion and amortization of $1.93 billion, impairment losses of $339 million and inventory valuation adjustments of $104 million.
Year Ended December 31, 2014
Cash provided by operating activities in 2014 was $3.17 billion and net income was $1.30 billion. The difference between net income and cash provided by operating activities in 2014 primarily consisted of non-cash items totaling $1.92 billion offset by net changes in operating assets and liabilities of $320 million. The non-cash activity in 2014 consisted primarily of depreciation, depletion and amortization of $1.67 billion, inventory valuation adjustments of $473 million and a goodwill impairment of $370 million offset slightly by the gain on the sale of AmeriGas common units of $177 million.
Year Ended December 31, 2013
Cash provided by operating activities in 2013 was $2.63 billion and net income was $746 million. The difference between net income and cash provided by operating activities in 2013 primarily consisted of non-cash items totaling $1.74 billion offset by net changes in operating assets and liabilities of $158 million. The non-cash activity in 2013 consisted primarily of depreciation, depletion and amortization of $1.30 billion, a goodwill impairment of $689 million, and deferred income taxes of $48 million offset slightly by the gain on the sale of AmeriGas common units of $87 million.
Investing Activities
Cash flows from investing activities primarily consist of cash amounts paid in 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, 2015
Cash used in investing activities in 2015 was $7.82 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $9.02 billion. Additional detail related to our capital expenditures is provided in the table below. We paid net cash of $804 million for acquisitions, including the acquisition of a noncontrolling interest.
Year Ended December 31, 2014
Cash used in investing activities in 2014 was $6.69 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $5.17 billion.

Additional detail related to our capital expenditures is provided in the table below. We paid net cash of $2.37 billion for acquisitions, primarily for the Eagle

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Rock Acquisition, Susser Merger and the acquisition of a noncontrolling interest. In addition, we received $814 million in cash from sale of AmeriGas common units.

Year Ended December 31, 2013

Cash used in investing activities in 2013 was $3.64 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $3.42 billion. Additional detail related to our capital expenditures is provided in the table below. In addition, we received $1.01 billion, and $346 million in cash from the sale of the MGE and NEG assets, and the sale of AmeriGas common units, respectively, and paid net cash of $1.74 billion for acquisitions, primarily for the ETP Holdco Acquisition and MACS.

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The following is a summary of our capital expenditures (net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Year Ended December 31, 2015:			
Direct(1):			
Intrastate transportation and storage	$74	$31	$105
Interstate transportation and storage(2)	741	119	860
Midstream	2,055	117	2,172
Liquids transportation and services(2)	2,091	18	2,109
Retail marketing(3)	259	63	322
All other (including eliminations)	337	46	383
Total direct capital expenditures	5,557	394	5,951
Indirect(1):			
Investment in Sunoco Logistics	2,042	84	2,126
Investment in Sunoco LP(3)	83	7	90
Total indirect capital expenditures	2,125	91	2,216
Total capital expenditures	$7,682	$485	$8,167
Year Ended December 31, 2014:			
Direct(1):			
Intrastate transportation and storage	$133	$36	$169
Interstate transportation and storage	301	110	411
Midstream	1,204	94	1,298
Liquids transportation and services	406	21	427
Retail marketing(3)	104	73	177
All other (including eliminations)	391	29	420
Total direct capital expenditures	2,539	363	2,902
Indirect(1):			
Investment in Sunoco Logistics	2,434	76	2,510
Investment in Sunoco LP(3)	77	5	82
Total indirect capital expenditures	2,511	81	2,592
Total capital expenditures	$5,050	$444	$5,494
Year Ended December 31, 2013:			
Direct(1):			
Intrastate transportation and storage	$18	$29	$47
Interstate transportation and storage	55	97	152
Midstream	1,033	81	1,114
Liquids transportation and services	426	22	448
Retail marketing(3)	113	63	176
All other (including eliminations)	326	46	372
Total direct capital expenditures	1,971	338	2,309
Indirect(1):			
Investment in Sunoco Logistics	965	53	1,018
Total indirect capital expenditures	965	53	1,018
Total capital expenditures	$2,936	$391	$3,327

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(1) Indirect capital expenditures comprise those funded by our publicly traded subsidiaries; all other capital expenditures are reflected as direct capital expenditures.
(2) Includes capital expenditures related to our proportionate ownership of the Bakken and Rover pipelines.
(3) The retail marketing segment includes our wholly-owned retail marketing operations, including Susser beginning on the acquisition date of August 29, 2014 until its contribution to Sunoco LP in July 2015.
(4) Investment in Sunoco LP includes capital expenditures for the period prior to deconsolidation on July 1, 2015.

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, 2015

Cash provided by financing activities was $4.94 billion in 2015. We received $1.43 billion in net proceeds from Common Unit offerings, and our subsidiaries received $1.52 billion in net proceeds from the issuance of common units. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, and acquisitions, as well as for general partnership purposes. In 2015, we had a net increase in our debt level of $4.85 billion primarily due to ETP's issuance of $2.50 billion and $3.00 billion in aggregate principal amount of senior notes in March 2015 and June 2015, respectively, and Sunoco Logistics' issuances of $1.00 billion in aggregate principal amount of senior notes in November 2015 (see Note 6 to our consolidated financial statements). In addition, we incurred debt issuance costs of $63 million. In 2015, we paid distributions of $3.13 billion to our partners and we paid distributions of $338 million to noncontrolling interests. In addition, we received capital contributions from noncontrolling interests of $841 million.

Year Ended December 31, 2014

Cash provided by financing activities was $3.62 billion in 2014. We received $1.38 billion in net proceeds from Common Unit offerings, and our subsidiaries received $1.24 billion in net proceeds from the issuance of common units. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, and acquisitions, as well as for general partnership purposes. In 2014, we had a net increase in our debt level of $2.65 billion primarily due to Sunoco Logistics' issuance of $2.00 billion in aggregate principal amount of senior notes in April 2014 and November 2014. In addition, we incurred debt issuance costs of $63 million. In 2014, we paid distributions of $1.96 billion to our partners and we paid distributions of $241 million to noncontrolling interests. Regency received net proceeds of $1.23 billion from the issuance of common units and paid distributions of $645 million to its partners.

Year Ended December 31, 2013

Cash provided by financing activities was $1.22 billion in 2013. We received $1.61 billion in net proceeds from Common Unit offerings. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, and acquisitions, as well as for general partnership purposes. In 2013, we had a net increase in our debt level of $1.99 billion primarily due to ETP's issuance of $1.25 billion and $1.50 billion in aggregate principal amount of senior notes in January 2013 and September 2013, respectively, and Sunoco Logistics' issuance of $700 million in aggregate principal amount of senior notes in January 2013 partially offset by repayments of long-term debt and credit facilities. In addition, we incurred debt issuance costs of $57 million. In 2013, we paid distributions of $1.80 billion to our partners and we paid distributions of $303 million to noncontrolling interests. Regency received net proceeds of $149 million from the issuance of common units and paid distributions of $342 million to its partners.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31,	
	2015	2014
ETP Senior Notes	$19,439	$10,890
Transwestern Senior Notes	782	782
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	465	715
Sunoco Logistics Senior Notes(1)	4,975	3,975
Regency Senior Notes(2)	—	5,089
Revolving credit facilities:		
ETP $3.75 billion Revolving Credit Facility due November 2019	1,362	570
Sunoco Logistics' subsidiary $35 million Revolving Credit Facility due April 2015(3)	—	35
Sunoco Logistics $2.5 billion Revolving Credit Facility due March 2020	562	150
Sunoco LP $1.5 billion Revolving Credit Facility due September 2019(4)	—	683
Regency $2.5 billion Revolving Credit Facility due November 2019(5)	—	1,504
Other long-term debt	32	223
Unamortized premiums, net of discounts and fair value adjustments	158	280
Deferred debt issuance costs	(181)	(142)
Total debt	28,679	25,839
Less: current maturities of long-term debt	126	1,008
Long-term debt, less current maturities	$28,553	$24,831

(1) Sunoco Logistics' 6.125% senior notes due May 15, 2016 were classified as long-term debt as of December 31, 2015 as Sunoco Logistics has the ability and intent to refinance such borrowings on a long-term basis.

(2) As discussed in Note 6, the Regency senior notes were redeemed and/or assumed by the Partnership.

(3) Sunoco Logistics' subsidiary $35 million Revolving Credit Facility matured in April 2015 and was repaid with borrowings from the Sunoco Logistics $2.50 billion Revolving Credit Facility.

(4) In connection with ETE's acquisition of Sunoco GP, the general partner of Sunoco LP, on July 1, 2015, ETP deconsolidated Sunoco LP.

(5) On April 30, 2015, in connection with the Regency Merger, the Regency Revolving Credit Facility was paid off in full and terminated.

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

ETP Senior Notes Assumptions and Offerings

In June 2015, ETP issued $650 million aggregate principal amount of 2.50% senior notes due June 2018, $350 million aggregate principal amount of 4.15% senior notes due October 2020, $1.0 billion aggregate principal amount of 4.75% senior notes due January 2026 and $1.0 billion aggregate principal amount of 6.125% senior notes due December 2045. ETP used the net proceeds of $2.98 billion from the offering to repay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

In March 2015, ETP issued $1.0 billion aggregate principal amount of 4.05% senior notes due March 2025, $500 million aggregate principal amount of 4.90% senior notes due March 2035, and $1.0 billion aggregate principal amount of 5.15% senior notes due March 2045. ETP used the $2.48 billion net proceeds from the offering to repay outstanding borrowings under the ETP Credit Facility, to fund growth capital expenditures and for general partnership purposes.

At the time of the Regency Merger, Regency had outstanding $5.1 billion principal amount of senior notes. On June 1, 2015, Regency redeemed all of the outstanding $499 million aggregate principal amount of its 8.375% senior notes due June 2019.

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On August 10, 2015, ETP entered into various supplemental indentures pursuant to which ETP has agreed to assume all of the obligations of Regency under the following series of outstanding senior notes of Regency and Regency Energy Finance Corp., of which ETP was previously a co-obligor or parent guarantor:

- $400 million in aggregate principal amount of 5.750% Senior Notes due 2020;
- $390 million in aggregate principal amount of 8.375% Senior Notes due 2020 (the "2020 Notes");
- $260 million in aggregate principal amount of 6.500% Senior Notes due 2021 (the "2021 Notes");
- $500 million in aggregate principal amount of 6.500% Senior Notes due 2021;
- $700 million in aggregate principal amount of 5.000% Senior Notes due 2022;
- $900 million in aggregate principal amount of 5.875% Senior Notes due 2022;
- $600 million in aggregate principal amount of 4.500% Senior Notes due 2023; and
- $700 million in aggregate principal amount of 5.500% Senior Notes due 2023.

The notes assumed from Regency are registered under the Securities Act of 1933 (as amended). The senior notes assumed from Regency may be redeemed at any time, or from time to time, pursuant to the terms of the applicable indenture and related indenture supplements related to the Regency senior notes. The balance is payable upon maturity and interest is payable semi-annually. The indentures on these notes contain various covenants that are similar to those of the indentures on ETP's senior notes.

The senior notes assumed from Regency are fully and unconditionally guaranteed, on a joint and several basis, by all of the consolidated subsidiaries that were previously consolidated by Regency, except for ELG and its wholly-owned subsidiaries, Aqua – PVR and ORS.

On August 13, 2015, ETP redeemed in full the outstanding amount of the 2020 Notes and the 2021 Notes. The amount paid to redeem the 2020 Notes included a make whole premium of approximately $40 million and the amount paid to redeem the 2021 Notes included a make whole premium of approximately $24 million.

Sunoco Logistics Senior Notes Offerings

In November 2015, Sunoco Logistics issued $600 million aggregate principal amount of 4.40% senior notes due April 2021 and $400 million aggregate principal amount of 5.95% senior notes due December 2025.

Credit Facilities

ETP Credit Facility

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

We use the ETP Credit Facility to provide temporary financing for our growth projects, as well as for general partnership purposes. We typically repay amounts outstanding under the ETP Credit Facility with proceeds from common 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 ETP Credit Facility depend on multiple factors, including market conditions and expectations of future working capital needs, and ultimately are a financing decision made by management. Therefore, the balance outstanding under the ETP Credit Facility may vary significantly between periods. 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 ETP Credit Facility with proceeds from common unit offerings or long-term note offerings.

As of December 31, 2015, the ETP Credit Facility had $1.36 billion outstanding, and the amount available for future borrowings was $2.24 billion after taking into account letters of credit of $145 million. The weighted average interest rate on the total amount outstanding as of December 31, 2015 was 1.86%.

Sunoco Logistics Credit Facility

Sunoco Logistics maintains a $2.50 billion unsecured credit facility (the "Sunoco Logistics Credit Facility") which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be extended to $3.25 billion under certain conditions.

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The Sunoco Logistics Credit Facility is available to fund Sunoco Logistics' working capital requirements, to finance acquisitions and capital projects, to pay distributions and for general partnership purposes. The Sunoco Logistics Credit Facility bears interest at LIBOR or the Base Rate, each plus an applicable margin. The credit facility may be prepaid at any time. As of December 31, 2015, the Sunoco Logistics Credit Facility had $562 million of outstanding borrowings.

Covenants Related to Our Credit Agreements

Covenants Related to ETP

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

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

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

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

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

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

Covenants Related to Panhandle

Panhandle is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of Panhandle's lending agreements. Financial covenants exist in certain of Panhandle's debt agreements that require Panhandle to maintain a certain level of net worth, to meet certain debt to total capitalization ratios and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. A failure by Panhandle to satisfy any such covenant would give rise to an event of default under the associated debt, which could become immediately due and payable if Panhandle did not cure such default within any permitted cure period or if Panhandle did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

Panhandle's restrictive covenants include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of Panhandle's debt and other financial obligations and that of its subsidiaries.

In addition, Panhandle and/or its subsidiaries are subject to certain additional restrictions and covenants. These restrictions and covenants include limitations on additional debt at some of its subsidiaries; limitations on the use of proceeds from borrowing at some of its subsidiaries; limitations, in some cases, on transactions with its affiliates; limitations on the incurrence of liens; potential limitations on the abilities of some of its subsidiaries to declare and pay dividends and potential limitations on some of its subsidiaries to participate in Panhandle’s cash management program; and limitations on Panhandle’s ability to prepay debt.

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Covenants Related to Sunoco Logistics
Sunoco Logistics' $2.50 billion credit facility contains various covenants, including limitations on the creation of indebtedness and liens, and other covenants related to the operation and conduct of the business of Sunoco Logistics and its subsidiaries. The credit facility also limits Sunoco Logistics, on a rolling four-quarter basis, to a maximum total consolidated debt to consolidated Adjusted EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1 during an acquisition period. Sunoco Logistics' ratio of total consolidated debt, excluding net unamortized fair value adjustments, to consolidated Adjusted EBITDA was 3.6 to 1 at December 31, 2015, as calculated in accordance with the credit agreements.

Compliance with our Covenants
We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2015.

Off-Balance Sheet Arrangements

Contingent Residual Support Agreement – AmeriGas
In connection with the closing of the contribution of its propane operations in January 2012, ETP agreed to provide contingent, residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third party purchases.

PEPL Holdings Guarantee of Collection
Panhandle previously agreed to fully and unconditionally guarantee (the "Panhandle Guarantee") all of the payment obligations of Regency and Regency Energy Finance Corp. under their $600 million in aggregate principal amount of 4.50% senior notes due November 2023. On May 28, 2015, ETP entered into a supplemental indenture relating to the senior notes pursuant to which it became a co-obligor with respect to such payment obligations thereunder. Accordingly, pursuant to the terms of such supplemental indentures the Panhandle Guarantee was terminated.

ETP Retail Holdings Guarantee of Sunoco LP Notes
In April 2015, Sunoco LP acquired a 31.58% equity interest in Sunoco, LLC from Retail Holdings for $775 million of cash and $41 million of Sunoco LP common units. The cash portion of the consideration was financed through Sunoco LP's issuance of $800 million principal amount of 6.375% senior notes due 2023. Retail Holdings entered into a guarantee of collection with Sunoco LP and Sunoco Finance Corp., a wholly owned subsidiary of Sunoco LP, pursuant to which Retail Holdings has agreed to provide a guarantee of collection, but not of payment, to Sunoco LP with respect to the principal amount of the senior notes issued by Sunoco LP.

Contractual Obligations
The following table summarizes our long-term debt and other contractual obligations as of December 31, 2015:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$28,702	$301	$2,832	$5,299	$20,270
Interest on long-term debt[1]	28,111	2,837	5,490	5,107	14,677
Payments on derivatives	136	5	115	16	—
Purchase commitments[2]	8,863	5,066	2,273	639	885
Transportation, natural gas storage and fractionation contracts	69	26	39	4	—
Operating lease obligations	485	57	97	79	252
Distributions and redemption of preferred units of a subsidiary[3]	93	3	7	7	76
Other[4]	148	43	48	45	12
Total[5]	$66,607	$8,338	$10,901	$11,196	$36,172

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(1) Interest payments on long-term debt are based on the principal amount of debt obligations as of December 31, 2015. With respect to variable rate debt, the interest payments were estimated using the interest rate as of December 31, 2015. 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, 2015 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) Assumes the outstanding ETP Preferred Units are redeemed for cash on September 2, 2029.

(4) Expected contributions to fund our pension and postretirement benefit plans were included in "Other" above. Environmental liabilities, asset retirement obligations, unrecognized tax benefits, contingency accruals and deferred revenue, which were included in "Other non-current liabilities" our consolidated balance sheets were excluded from the table above as such amounts do not represent contractual obligations or, in some cases, the amount and/or timing of the cash payments is uncertain.

(5) Excludes non-current deferred tax liabilities of $4.08 billion due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Cash Distributions Paid by ETP

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

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 7, 2013	February 14, 2013	$0.8938
March 31, 2013	May 6, 2013	May 15, 2013	0.8938
June 30, 2013	August 5, 2013	August 14, 2013	0.8938
September 30, 2013	November 4, 2013	November 14, 2013	0.9050
December 31, 2013	February 7, 2014	February 14, 2014	0.9200
March 31, 2014	May 5, 2014	May 15, 2014	0.9350
June 30, 2014	August 4, 2014	August 14, 2014	0.9550
September 30, 2014	November 3, 2014	November 14, 2014	0.9750
December 31, 2014	February 6, 2015	February 13, 2015	0.9950
March 31, 2015	May 8, 2015	May 15, 2015	1.0150
June 30, 2015	August 6, 2015	August 14, 2015	1.0350
September 30, 2015	November 5, 2015	November 16, 2015	1.0550
December 31, 2015	February 8, 2016	February 16, 2016	1.0550

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The total amounts of distributions declared during the periods presented (all from Available Cash from our operating surplus and are shown in the year with respect to which they relate):

	Years Ended December 31,		
	2015	2014	2013
Common Units held by public[(1)]	$1,970	$1,179	$997
Common Units held by ETE	54	119	268
Class H Units held by ETE	263	219	105
General Partner interest held by ETE	31	21	20
Incentive distributions held by ETE [(1)]	1,261	754	701
IDR relinquishments net of Class I unit distributions	(111)	(250)	(199)
Total distributions declared to the partners of ETP	$3,468	$2,042	$1,892

(1) The increases for the year ended December 31, 2015 include the impacts from Common Units issued in the Regency Merger, as well as increases in distributions per unit.

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

	Total Year
2016	$137
2017	128
2018	105
2019	95

Cash Distributions Paid by Sunoco Logistics

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

Distributions declared during the periods presented were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2012	February 8, 2013	February 14, 2013	$0.2725
March 31, 2013	May 9, 2013	May 15, 2013	0.2863
June 30, 2013	August 8, 2013	August 14, 2013	0.3000
September 30, 2013	November 8, 2013	November 14, 2013	0.3150
December 31, 2013	February 10, 2014	February 14, 2014	0.3312
March 31, 2014	May 9, 2014	May 15, 2014	0.3475
June 30, 2014	August 8, 2014	August 14, 2014	0.3650
September 30, 2014	November 7, 2014	November 14, 2014	0.3825
December 31, 2014	February 9, 2015	February 13, 2015	0.4000
March 31, 2015	May 11, 2015	May 15, 2015	0.4190
June 30, 2015	August 10, 2015	August 14, 2015	0.4380
September 30, 2015	November 9, 2015	November 13, 2015	0.4580
December 31, 2015	February 8, 2016	February 12, 2016	0.4790

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

	Years Ended December 31,		
	2015	2014	2013
Limited Partners:			
Common units held by public	$344	$225	$173
Common units held by ETP	120	100	82
General Partner interest held by ETP	12	10	5
Incentive distributions held by ETP	281	175	117
Total distributions declared	$757	$510	$377

New Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In August 2015, the FASB deferred the effective date of ASU 2014-09, which is now effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is permitted as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within those annual periods. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In February 2015, the FASB issued Accounting Standards Update No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis ("ASU 2015-02"), which changed the requirements for consolidation analysis. Under ASU 2015-02, reporting entities are required to evaluate whether they should consolidate certain legal entities. ASU 2015-02 is effective for fiscal years beginning after December 15, 2015, and early adoption was permitted. We expect to adopt this standard for the year ended December 31, 2016, and we do not anticipate a material impact to our financial position or results of operations as a result of the adoption of this standard.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30) ("ASU 2015-03"), which simplifies the presentation of debt issuance costs by requiring debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the debt liability rather than as an asset. ASU 2015-03 is effective for annual reporting periods after December 15, 2015, including interim periods within that reporting period, with early adoption permitted for financial statements that have not been previously issued. Upon adoption, ASU 2015-03 must be applied retrospectively to all prior reporting period presented. We adopted and applied this standard to all consolidated financial statements presented and there was not a material impact to our financial position or results of operations as a result of the adoption of this standard.

In August 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805) - Simplifying the Accounting for Measurement-Period Adjustments. This update requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Additionally, this update requires that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. Finally, this update requires an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments in this update are effective for financial statements issued with fiscal years beginning after December 15, 2015, including interim periods within that reporting period. We do not anticipate a material impact to our financial position or results of operations as a result of the adoption of this standard.

In November 2015, the FASB issued ASU No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes (“ASU 2015-17”), which is intended to improve how deferred taxes are classified on organizations’ balance sheets. The ASU eliminates the current requirement for organizations to present deferred tax liabilities and assets as current and noncurrent in a classified balance sheet. Instead, organizations are now required to classify all deferred tax assets and liabilities as noncurrent.

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We adopted the provisions of ASU 2015-17 upon issuance and prior period amounts have been reclassified to conform to the current period presentation.

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, 2015 represent the actual results in all material respects.

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

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

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

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

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues. Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, 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.

Our retail marketing segment sells gasoline and diesel in addition to a broad mix of merchandise such as groceries, fast foods and beverages at its convenience stores. A portion of our gasoline and diesel sales are to wholesale customers on a consignment basis, in which we retain title to inventory, control access to and sale of fuel inventory, and recognize revenue at the time the fuel is sold to the ultimate customer. We typically own the fuel dispensing equipment and underground storage tanks at consignment sites,

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and in some cases we own the entire site and have entered into an operating lease with the wholesale customer operating the site. In addition, our retail outlets derive other income from lottery ticket sales, money orders, prepaid phone cards and wireless services, ATM transactions, car washes, movie rental and other ancillary product and service offerings. Some of Sunoco, Inc.'s retail outlets provide a variety of car care services. Revenues related to the sale of products are recognized when title passes, while service revenues are recorded on a net commission basis and are recognized when services are provided. Title passage generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements. In addition, revenues are not recognized until sales prices are fixed or determinable and collectability is reasonably assured.

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

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

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

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

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

Fair Value of Financial Instruments. We have commodity derivatives, interest rate derivatives and embedded derivatives in our preferred units that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. Derivatives related to the embedded derivatives in our preferred units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected value, and are considered level 3. See further information on our fair value assets and liabilities in Note 2 of our consolidated financial statements.

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Impairment of Long-Lived Assets and Goodwill. Long-lived assets are required to be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Goodwill and intangibles with indefinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized only if the carrying amount of the asset/goodwill is not recoverable and exceeds its fair value.

In order to test for recoverability when performing a quantitative impairment test, we must make estimates of projected cash flows related to the asset, which include, but are not limited to, assumptions about the use or disposition of the asset, estimated remaining life of the asset, and future expenditures necessary to maintain the asset's existing service potential. In order to determine fair value, we make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of natural gas, our ability to negotiate favorable sales agreements, the risks that natural gas exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers of natural gas, and competition from other companies, including major energy producers. While we believe we have made reasonable assumptions to calculate the fair value, if future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations.

Property, Plant and Equipment. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the consolidated statement of operations. Depreciation of property, plant and equipment is provided using the straight-line method based on their estimated useful lives ranging from 1 to 99 years. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. We do not anticipate future changes in the estimated useful lives of our property, plant and equipment.

Asset Retirement Obligations. We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. These fair value assessments are considered to be level 3 measurements, as they are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. We will record an asset retirement obligation in the periods in which management can reasonably estimate the settlement dates.

Except for certain amounts recorded by Panhandle, Sunoco Logistics and our retail marketing operations, discussed below, management was not able to reasonably measure the fair value of asset retirement obligations as of December 31, 2015 and 2014, in most cases because the settlement dates were indeterminable. Although a number of other onshore assets in Panhandle's system are subject to agreements or regulations that give rise to an ARO upon Panhandle's discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement. Sunoco, Inc. has legal asset retirement obligations for several other assets at its refineries, pipelines and terminals, for which it is not possible to estimate when the obligations will be settled. Consequently, the retirement obligations for these assets cannot be measured at this time. At the end of the useful life of these underlying assets, Sunoco, Inc. is legally or contractually required to abandon in place or remove the asset. Sunoco Logistics believes it may have additional asset retirement obligations related to its pipeline assets and storage tanks, for which it is not possible to estimate whether or when the retirement obligations will be settled. Consequently, these retirement obligations cannot be measured at this time.

Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. We have in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely

Long-lived assets related to AROs aggregated $18 million and were reflected as property, plant and equipment on our balance sheet as of December 31, 2015 and 2014. In addition, the Partnership had $6 million legally restricted for the purpose of settling AROs that was reflected as other non-current assets as of December 31, 2015.

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

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

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

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

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

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

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

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

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

In addition to the probable and estimable losses which have been recorded, management believes it is reasonably possible (i.e., less than probable but greater than remote) that additional environmental remediation losses will be incurred. At December 31, 2015, the aggregate of the estimated maximum reasonably possible losses, which relate to numerous individual sites, totaled approximately $5 million. This estimate of reasonably possible losses comprises estimates for remediation activities at current logistics and retail assets and, in many cases, reflects the upper end of the loss ranges which are described above. Such estimates include potentially higher contractor costs for expected remediation activities, the potential need to use more costly or comprehensive remediation methods and longer operating and monitoring periods, among other things.

Total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years. Management believes that the Partnership's exposure to adverse developments with respect to any individual site is not expected to be material. However, if changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could impact multiple facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur; however, management does not believe that any such charges would have a material adverse impact on the Partnership's consolidated financial position.

Deferred Income Taxes. ETP recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards ("NOLs") and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce deferred tax assets to an amount that is more likely than not to be realized by the Partnership in the future. Deferred income tax assets attributable to state and federal NOLs and federal tax alternative minimum tax credit carryforwards totaling $155 million have been included in ETP's consolidated balance sheet as of December 31, 2015. All of the deferred income tax assets attributable to state and federal NOL benefits expire before 2035 as more fully described below. The state NOL carryforward benefits of $122 million (net of federal benefit) begin to expire in 2016 with a substantial portion expiring between 2029 and 2035. The federal NOLs of $18 million ($6 million in benefits) will expire in 2032 and 2034. Federal alternative minimum tax credit carryforwards of $27 million remained at December 31, 2015. We have determined that a valuation allowance totaling $121 million (net of federal income tax effects) is required for the state NOLs at December 31, 2015 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 "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;

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- 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.

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

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

We use 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 and transportation costs in our retail marketing segment. 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.

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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, 2015			December 31, 2014		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	(602,500)	$(1)	$—	(232,500)	$(1)	$—
Basis Swaps IFERC/NYMEX[1]	(31,240,000)	(1)	—	(13,907,500)	—	—
Options – Calls	—	—	—	5,000,000	—	—
Power (Megawatt):						
Forwards	357,092	—	2	288,775	—	1
Futures	(109,791)	2	—	(156,000)	2	—
Options – Puts	260,534	—	—	(72,000)	—	1
Options – Calls	1,300,647	—	3	198,556	—	—
Crude (Bbls) – Futures	(591,000)	4	3	—	—	—
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(6,522,500)	—	—	57,500	(3)	—
Swing Swaps IFERC	71,340,000	(1)	—	46,150,000	2	1
Fixed Swaps/Futures	(14,380,000)	(1)	5	(34,304,000)	30	10
Forward Physical Contracts	21,922,484	4	5	(9,116,777)	—	3
Natural Gas Liquid (Bbls) – Forwards/Swaps	(8,146,800)	10	13	(4,417,400)	71	18
Refined Products (Bbls) – Futures	(993,000)	9	5	13,745,755	15	11
Corn (Bushels) – Futures	1,185,000	—	1	—	—	—
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(37,555,000)	—	—	(39,287,500)	3	1
Fixed Swaps/Futures	(37,555,000)	73	9	(39,287,500)	48	12

(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, 2015, we had $3.59 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $36 million annually; however, our actual change in interest expense

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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 (dollars in millions), none of which are designated as hedges for accounting purposes:

Term	Type[1]	Notional Amount Outstanding December 31, 2015	December 31, 2014
July 2015[2]	Forward-starting to pay a fixed rate of 3.38% and receive a floating rate	$—	$200
July 2016[3]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	200	200
July 2017[4]	Forward-starting to pay a fixed rate of 3.84% and receive a floating rate	300	300
July 2018[4]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
July 2019[4]	Forward-starting to pay a fixed rate of 3.25% and receive a floating rate	200	300
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	—
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	—
February 2023	Pay a floating rate plus a spread of 1.73% and receive a fixed rate of 3.60%	—	200

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

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

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

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

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $167 million as of December 31, 2015. For the $1.50 billion of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $53 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

Credit Risk

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

The Partnership’s counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, gas and electric utilities, midstream companies and independent power generators. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory

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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, 2015.

Management’s Report on Internal Control over Financial Reporting

The management of Energy Transfer Partners, 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, 2015.
Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2015, as stated in their report, which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

Energy Transfer Partners, L.P.

We have audited the internal control over financial reporting of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2015, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in the 2013 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2015, and our report dated February 29, 2016 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas

February 29, 2016

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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, 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

On February 25, 2016, in connection with his removal as Group Chief Financial Officer and Head of Business Development of ETE and his termination of employment with our General Partner, the members of the General Partner removed Jamie Welch as a director.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our General Partner manages and directs all of our activities. The activities of our General Partner 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. ETE, 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 December 31, 2015, our Board of Directors was comprised of seven persons, four of whom qualified as "independent" under the NYSE's corporate governance standards. Our Board of Directors determined that Messrs. Collins, Grimm, Perry, and Skidmore 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, and Matthew S. Ramsey, ETP LLC's President and Chief Operating Officer, as well as Tom Long, the Group Chief Financial Officer of ETE's general partner and Marshall S. McCrea III, the Group Chief Operating Officer and Chief Commercial Officer of ETE's general partner.

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 ETE 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 ETE 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 and will be provided in print form to any Unitholder requesting such information.

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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

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this annual report. In 2015, 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 2015. A description of the qualifications of Mr. Skidmore may be found elsewhere in this Item under “Directors and Executive Officers of the General Partner.”

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

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, our Board of Directors has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans adopted by our Unitholders, including the performance standards or other restrictions pertaining to the vesting of any such awards. Pursuant to the charter of the Compensation Committee, a director serving as a member of the Compensation Committee may not be an officer of or employed by the General Partner, the Partnership or its subsidiaries. Michael K. Grimm and David K. Skidmore serve

as the members of the Compensation Committee and Mr. Grimm serves as the chairman of the Compensation Committee. Our Board of Directors has determined that both Messrs. Grimm and Skidmore are “independent” (as that term is defined in the applicable NYSE corporate governance standards).
The Compensation Committee’s responsibilities include, among other duties, the following:
- annually review and approve goals and objectives relevant to compensation of the CEO, if applicable;

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- annually evaluate the CEO's performance in light of these goals and objectives, and make recommendations to the Board of Directors with respect to the CEO's compensation levels, if applicable, based on this evaluation;
- based on input from, and discussion with, the CEO, make recommendations to the Board of Directors with respect to non-CEO executive officer compensation, including incentive compensation and compensation under equity- based plans;
- make determinations with respect to the grant of equity-based awards to executive officers under our equity incentive plans;
- periodically evaluate the terms and administration of ETP's short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with ETP's goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments, if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or executive officer compensation; and
- perform other duties as deemed appropriate by the Board of Directors.

Matters relating to the nomination of directors or corporate governance matters are addressed to and determined by the full Board of Directors.

Code of Business Conduct and Ethics

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

Meetings of Non-management Directors and Communications with Directors

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

We have established a procedure by which Unitholders or interested parties may communicate directly with the Board of Directors, any committee of the Board, any 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 Partners, 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.

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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 29, 2016. Executive officers and directors are elected for one-year terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	60	Chief Executive Officer and Chairman of the Board of Directors
Matthew S. Ramsey	60	President and Chief Operating Officer
Thomas E. Long	59	Chief Financial Officer
Marshall S. (Mackie) McCrea, III	56	Director and ETE Group Chief Operating Officer and Chief Commercial Officer
James M. Wright, Jr.	47	General Counsel
Thomas P. Mason	59	Executive Vice President and General Counsel
Michael J. Hennigan	56	Director, President and Chief Executive Officer of Sunoco Logistics
A. Troy Sturrock	45	Vice President, Controller and Principal Accounting Officer
Ted Collins, Jr.	77	Director
Michael K. Grimm	61	Director
James R. (Rick) Perry	65	Director
David K. Skidmore	60	Director

Messrs. Warren and Ramsey also serve as directors of ETE’s general partner.
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 our General Partner and has served in that capacity since August 2007. Prior to that, Mr. Warren had served as the Co-Chief Executive Officer and Co-Chairman of the Board of our General Partner since the combination of the midstream and intrastate transportation and storage operations of ETC OLP and the retail propane operations of HOLP in January 2004. Prior to the combination of the operations of ETC OLP and HOLP, Mr. Warren served as President of the general partner of ET Company I, Ltd., having served in that capacity since 1996. From 1996 to 2000, he also served as a director of Crosstex Energy, Inc. From 1993 to 1996, he served as President, Chief Operating Officer and a Director of Cornerstone Natural Gas, Inc. Mr. Warren has more than 25 years of business experience in the energy industry. The Board of Directors selected Mr. Warren to serve as a director and as Chairman because he is the Partnership’s Chief Executive Officer and has more than 25 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States, and brings a unique and valuable perspective to the Board of Directors.
Matthew S. Ramsey. Mr. Ramsey was appointed as a director of ETE’s general partner on July 17, 2012 and as a director of ETP’s general partner on November 9, 2015. Mr. Ramsey currently serves as President and Chief Operating Officer of ETP’s general partner since November 2015. Mr. Ramsey is also a director of Sunoco LP, serving as chairman of Sunoco LP’s board since April 2015. Mr. Ramsey previously served as President of RPM Exploration, Ltd., a private oil and gas exploration partnership generating and drilling 3-D seismic prospects on the Gulf Coast of Texas. Mr. Ramsey is currently a director of RSP Permian, Inc. (NYSE: RSPP), where he serves as chairman of the compensation committee and as a member of the audit committee. Mr. Ramsey formerly served as President of DDD Energy, Inc. until its sale in 2002. From 1996 to 2000, Mr. Ramsey served as President and Chief Executive Officer of OEC Compression Corporation, Inc., a publicly traded oil field service company, providing gas compression services to a variety of energy clients. Previously, Mr. Ramsey served as Vice President of Nuevo Energy Company, an independent energy company. Additionally, he was employed by Torch Energy Advisors, Inc., a company providing management and operations services to energy companies including Nuevo Energy, last serving as Executive Vice President. Mr. Ramsey joined Torch Energy as Vice President of Land and was named Senior Vice President of Land in 1992. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey is a graduate of Harvard Business School Advanced Management Program. Mr. Ramsey is licensed to practice law in the State of Texas. He is qualified to practice in the Western District of Texas and the United States Court of Appeals for the Fifth Circuit. Mr. Ramsey formerly served as a director of Southern Union

Company. The members of our General Partner recognize Mr. Ramsey’s vast experience in the oil and gas space and believe that he provides valuable industry insight as a member of our Board of Directors.

Thomas E. Long. Mr. Long is the Group Chief Financial Officer of ETE since February 2016. Mr. Long previously served as Chief Financial Officer of our General Partner since April 2015 and as Executive Vice President and Chief Financial Officer of Regency GP LLC from November 2010 to April 2015. From May 2008 to November 2010, Mr. Long served as Vice President and Chief Financial Officer of Matrix Service Company. Prior to joining Matrix, he served as Vice President and Chief Financial Officer of DCP Midstream Partners, LP, a publicly traded natural gas and natural gas liquids midstream business company located in Denver, CO. In that position, he was responsible for all financial aspects of the company since its formation in December 2005. From 1998 to 2005, Mr. Long served in several executive positions with subsidiaries of Duke Energy Corp., one of the nation's largest electric power companies.

Marshall S. (Mackie) McCrea, III. Mr. McCrea is the Group Chief Operating Officer and Chief Commercial Officer for the Energy Transfer family and has served in that capacity since November 2015. Mr. McCrea was appointed as a director on December 23, 2009. Prior to that, he was the President and Chief Operating Officer of our General Partner and has served in that capacity from June 2008 to November 2015. Prior to that, he served as President – Midstream of our General Partner from March 2007 to June 2008. Previously he served as the Senior Vice President – Commercial Development since the combination of the operations of ETC OLP and HOLP in January 2004. In March 2005, Mr. McCrea was named president of ETC OLP. Prior to the combination of the operations of ETC OLP and HOLP, Mr. McCrea served as Senior Vice President – Business Development and Producer Services of the general partner of ETC OLP and ET Company I, Ltd., having served in that capacity since 1997. Mr. McCrea also currently serves on the Board of Directors of the general partner of ETE, of Sunoco Logistics and of Sunoco LP. The Board of Directors 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. Jim Wright was elected General Counsel of our General Partner in December 2015. 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 since May 2008. 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.

Thomas P. Mason. Tom Mason became Executive Vice President and General Counsel of the general partner of ETE in December 2015. Mr. Mason served as Senior Vice President, General Counsel and Secretary of our General Partner from April 2012 to December 2015. Mr. Mason previously served as Vice President, General Counsel and Secretary from June 2008 and as General Counsel and Secretary of our General Partner from February 2007. Prior to joining ETP, he was a partner in the Houston office of Vinson & Elkins. Mr. Mason has specialized in securities offerings and mergers and acquisitions for more than 25 years. Mr. Mason also serves on the Board of Directors of the general partner of Sunoco Logistics.

Michael P. Hennigan. Mr. Hennigan was elected to the Board of Sunoco Logistics in April 2010. He was elected President and Chief Executive Officer, effective March 1, 2012. Prior to that, he was President and Chief Operating Officer from July 2010 until March 2012. From May 2009 until July 2010, Mr. Hennigan served as Vice President, Business Development. Prior to joining the general partner of Sunoco Logistics, he was employed in the following positions at Sunoco, Inc.: Senior Vice President, Business Improvement from October 2008 to May 2009, and Senior Vice President, Supply, Trading, Sales and Transportation from February 2006 to October 2008. Mr. Hennigan has served as a member of the board of directors of Niska Gas Storage Partners LLC since September 10, 2014.

A. Troy Sturrock. Mr. Sturrock has served as the Vice President and Controller of Energy Transfer Partners, L.L.C. since June 2015. 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. From January 2004 to June 2006, Mr. Sturrock was associated with the Public Company Accounting Oversight Board, where he was an inspection specialist in the division of registration and inspections. Mr. Sturrock served in various roles at PricewaterhouseCoopers LLP from 1995 to 2004, most recently as a senior manager in the audit practice specializing in the transportation and energy industries. Mr. Sturrock is a Certified Public Accountant.

Ted Collins, Jr. Mr. Collins has been an independent oil and gas producer since 2000. He also serves as a Director of Oasis Petroleum Corp., CLL Global Research Foundation and RSP Permian, Inc. (NYSE: RSPP). Mr. Collins is also the Chairman of the Board of Managers of Coronado Midstream, LLC. He has also served on both the Audit

Committee and Nominating and Governance Committee for Oasis Petroleum Corp. since May of 2011. Mr. Collins previously served as President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988 Mr. Collins was President of Enron Oil & Gas Co. and its predecessors, HNG Oil Company and HNG Internorth Exploration Co. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quasar Petroleum Company. Mr. Collins has served as a director of our General Partner since August 2004. Mr. Collins is a past President of the Permian Basin Petroleum Association; the Permian Basin Landmen's Association, the Petroleum Club of Midland and has served as Chairman of the Midland Wildcat Committee since 1984. The Board selected Mr. Collins to serve as a director because of his previous experience as an executive in various positions

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in the oil and gas industry. In addition, as a public company director at various other companies, Mr. Collins has been involved in succession planning, compensation, employee management and the evaluation of acquisition properties.

Michael K. Grimm. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and served as its President and Chief Executive Officer from 1995 until 2006 when it was sold. Currently, Mr. Grimm is President of Rising Star Energy Development Company, Rising Star Petroleum, LLC and is Chairman of the Board of RSP Permian (NYSE: RSPP), which is active in the drilling and developing of West Texas Permian Basin oil reserves. Prior to the formation of the first Rising Star companies, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for 13 years. Mr. Grimm has been an active member of the Independent Petroleum Association of America, the American Association of Professional Landmen, Dallas Producers Club, Dallas Wildcat Committee, and Fort Worth Wildcatters. Mr. Grimm has served as a director of our General Partner since December 2005 and is Chairman of the Audit Committee and the Compensation Committee. He has a B.B.A. from the University of Texas at Austin. The Board selected Mr. Grimm to serve as a director because of his extensive experience in the energy industry and his service as a senior executive at several energy-related companies, in addition to his contacts in the industry gained through his involvement in energy-related organizations.

James R. (Rick) Perry. Mr. Perry has served as a director of our general partner since February 2015. Prior to joining ETP, Mr. Perry served as Governor of the State of Texas from 2000 to 2015. Mr. Perry served as Lieutenant Governor of Texas from 1998 to 2000, and as Agriculture Commissioner from 1991 to 1998. Prior to 1991, Mr. Perry also served in the Texas House of Representatives. The Board selected Mr. Perry to serve as a director because of his vast experience as an executive in the highest office of state government. In addition, Mr. Perry has been involved in finance and budget planning processes throughout his career in government as a member of the Texas House Appropriations Committee, the Legislative Budget Board and as Governor.

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 a member of both the Audit Committee and Compensation Committee. The Board selected Mr. Skidmore 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 and production 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.

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 and the Operating Companies. Our General Partner and its affiliates performing services for the Partnership and the Operating Companies 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 Operating Companies, and thus, our General Partner does not incur additional reimbursable costs.

Our General Partner is ultimately controlled by the general partner of ETE, 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 8 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per unit distributions equal the per unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership and changes in beneficial ownership with the SEC. Officers,

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directors and greater than 10% Unitholders are required by SEC regulations to furnish the General Partner with copies of all Section 16(a) forms.

Based solely on our review of the copies of such forms received by us, or written representations from reporting persons, we believe that during the year ended December 31, 2015, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner, except as set forth below:

- a late Form 4 filed by Mr. David Skidmore on September 2, 2015;
- a late Form 4 filed by Mr. Kelcy Warren on June 30, 2015; and
- a late Form 3 filed by Mr. Robert Owens on March 25, 2015.

ITEM 11. EXECUTIVE COMPENSATION

Overview

As a limited partnership, we are managed by our General Partner, which in turn is managed by its general partner, ETP LLC, which we refer to in this Item as "our General Partner." As of December 31, 2015, ETE owned 100% of our General Partner, approximately 0.5% of our outstanding Common Units and 100% of our outstanding Class H and Class I Units. All of our employees are employed by and receive employee benefits from our Operating Companies.

Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of our management functions. As a result, the executive officers of our General Partner are essentially our executive officers, and their compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of our General Partner as set forth below. The executive officers we refer to in this discussion as our "named executive officers" are the following officers of our General Partner:

- Kelcy L. Warren, Chairman and Chief Executive Officer;
- Marshall S. (Mackie) McCrea, III, former President and Chief Operating Officer and current Group Chief Operating Officer and Chief Commercial Officer of ETE's general partner;
- Matthew S. Ramsey, President and Chief Operating Officer;
- Thomas E. Long, Chief Financial Officer and Group Chief Financial Officer of ETE's general partner;
- Martin Salinas, Jr., former Chief Financial Officer;
- Thomas P. Mason, former Senior Vice President, General Counsel and Secretary and current Executive Vice President and General Counsel of ETE's general partner; and
- Michael J. Hennigan, President and Chief Executive Officer of Sunoco Partners LLC.

In November 2015, Mr. McCrea was promoted to Group Chief Operating Officer and Chief Commercial Officer of ETE's general partner and Mr. Ramsey was appointed as President and Chief Operating Officer of our General Partner to replace Mr. McCrea. In December 2015, Mr. Mason was promoted from Senior Vice President, General Counsel and Secretary of our General Partner to Executive Vice President and General Counsel of ETE's general partner. As Messrs. McCrea and Mason served our General Partner in their ETP executive capacities for significant portions of 2015, we have included them as named executive officers herein.

During 2015, Mr. Hennigan's primary business responsibilities related to ETP's Investment in Sunoco Logistics segment, including Sunoco Logistics and its consolidated subsidiaries. The compensation committee of Sunoco Logistics' general partner sets the components of Mr. Hennigan's compensation, including salary, long-term incentive awards and annual bonus utilizing the same philosophy and methodology adopted by our General Partner.

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Effective April 30, 2015, Mr. Salinas resigned as Chief Financial Officer of our General Partner and terminated his employment. In recognition of his services to ETP, Mr. Salinas and ETP entered into a Separation and Non-Solicit Agreement and Full Release of Claims (the "Separation Agreement"), which became effective, after expiration of a revocation period, on May 9, 2015. The Separation Agreement, from a compensation perspective provided for:

(i) Payment to Mr. Salinas of a lump sum total gross amount equal to $307,500, less all required government payroll deductions and withholding, which is an amount equal to eight months of Mr. Salinas' base salary;

(ii) An additional lump sum payment to Mr. Salinas of $546,750, less all required government payroll deductions and withholding, which is an amount equal to Mr. Salinas' target bonus award for 2015 under the Energy Transfer Partners, L.L.C. Annual Bonus Plan (the "Bonus Plan");

(iii) Payment by ETP of the full cost of Mr. Salinas' premium for continued health insurance coverage under ETP's health insurance plan and the Consolidated Omnibus Budget Reconciliation Act for a period of seven months; and

(iv) Acceleration of the vesting of all unvested restricted common units awarded to Mr. Salinas pursuant to the terms of the Second Amended and Restated Partnership 2008 Long Term Incentive Plan (the "2008 Incentive Plan") and the Sunoco Partners LLC Long Term Incentive Plan, as amended (the "Sunoco Logistics Plan"). As of May 9, 2015, Mr. Salinas had outstanding awards under the 2008 Incentive Plan of 61,841 restricted common units and 32,600 restricted common units under the Sunoco Logistics Plan that were otherwise not scheduled to vest until after the Employee's termination of employment.

Our 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 the named executive officers that provides for a slightly below the median market annual base compensation rate (i.e. approximately the 40^{th} percentile of market) but incentive-based compensation composed of a combination of compensation vehicles to reward both short and long-term performance that are both targeted to pay-out at approximately the top-quartile of market. Our General Partner believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of the Partnership's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of our 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 awards under our equity incentive plan(s), which awards are intended to provide a longer term incentive and retention value to our key employees to focus their efforts on increasing the market price of our publicly traded units and to increase the cash distribution we pay to our Unitholders.

Prior to December 2012, our equity awards were primarily in the form of restricted unit awards that vest over a specified time period, with substantially all of these awards vesting over a five-year period at 20% per year based generally on continued employment through each specified vesting date. Beginning in December 2012, we began granting restricted unit awards that vest, based generally upon continued employment, at a rate of 60% after the third anniversary of the award and the remaining 40% after the fifth anniversary of the award. Our General Partner believes that these equity-based incentive arrangements are important in attracting and retaining our executives and key employees as well as motivating these individuals to achieve our business objectives. The equity-based compensation also reflects the importance we place on aligning the interests of our executives, including the named executive officers with those of our Unitholders.

While we are responsible for the direct payment of the compensation of our named executive officers as employees of ETP or its controlled affiliates, ETP does not participate or have any input in any decisions as to the compensation policies of our General Partner or the compensation levels of the executive officers of our General Partner. The compensation committee of the board of directors of our General Partner (the "ETP Compensation Committee") is responsible for the approval of the compensation policies and the compensation levels of these executive officers. We directly pay these executive officers in lieu of receiving an allocation of overhead related to executive compensation from our General Partner. For a more detailed description of the compensation of our named executive officers, please see "Compensation Tables" below.

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

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

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- 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, 2015, the compensation paid to our named executive officers, other than our Chief Executive Officer, consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- time-vested restricted unit awards under the equity incentive plan(s);
- payment of distribution equivalent rights (“DERs”) on unvested time-based restricted unit awards under our equity incentive plan(s);
- vesting of previously issued time-based awards issued pursuant to our equity incentive plan(s);
- compensation resulting from the vesting of equity issuances made by an affiliate; and
- 401(k) plan employer contributions.

Mr. Warren, our Chief Executive Officer, 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).

Methodology

The ETP Compensation Committee considers relevant data available to it to assess our competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers. The Compensation Committee also considers individual performance, levels of responsibility, skills and experience. Periodically, the compensation committee of the general partner of ETE (the “ETE Compensation Committee”) or the ETP Compensation Committee engages a third-party consultant to provide market information for compensation levels at peer companies in order to assist in the determination of compensation levels for our executives, including the named executive officers. In 2015, Longnecker & Associates (“Longnecker”) evaluated the market competitiveness of total compensation levels of a number of executives of ETE, ETP and Sunoco Logistics to provide market information with respect to compensation of those executives. In particular, the review by Longnecker was designed to (i) evaluate the market competitiveness of total compensation levels for certain members of senior management, including our named executive officers; (ii) assist in the determination of appropriate compensation levels for our senior management, including the named executive officers; and (iii) confirm that our compensation programs were yielding compensation packages consistent with our overall compensation philosophy. This review by Longnecker was deemed necessary to update the most recent review by Mercer (US) Inc. during 2013, especially in light of the on-going growth of the family of partnerships as a result of the series of transforming transactions we have completed over the past few years, which have continued to significantly increase our size and scale from both a financial and asset perspective.

In conducting its review, Longnecker specifically considered the larger size of the combined ETE and ETP entities from an energy industry perspective, to form a public peer group, inclusive of energy and non-energy related peers, against which ETE and ETP can compare total compensation for its executives, including the named executive officers. We worked with Longnecker in the development of the final “peer group” of leading companies in the energy industry that most closely reflect our profile in terms of revenues, assets and market value as well as compete with us for talent at the senior management level and similarly situated general industry companies with similar revenues, assets and market value. The identified companies were:

Energy Peer Group:

• Conoco Phillips
• Enterprise Products Partners, L.P.
• Plains All American Pipeline, L.P.
• Halliburton Company
• Valero Energy Corporation
• Anadarko Petroleum
• Marathon Oil Corporation
• Kinder Morgan Energy Partners, L.P.
• The Williams Companies, Inc.

General Industry Peer Group:

• The Boeing Company
• Dow Chemical Company
• Caterpillar Inc.
• Lockheed Martin Corporation
• Deere & Company
• United Technologies Corporation
• United Parcel Service, Inc.
• FedEx Corporation
• Honeywell International Inc.

The compensation analysis provided by Longnecker covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term incentive awards for the senior executives of these companies. In preparing the review materials, Longnecker utilized generally accepted compensation principles as determined by WorldatWork and gathered data from the public peer companies and published salary surveys.

The ETP Compensation Committee reviewed the information provided by Longnecker, including Longnecker’s specific conclusions and recommended considerations for all compensation going forward, but focused specifically on the industry related data to compare the levels of annual base salary, annual short-term cash bonus and long-term equity incentive awards at these other companies with those of our named executive officers to ensure that compensation of our named executive officers is both consistent with our compensation philosophy and competitive with the compensation for executive officers of these other companies. The ETP Compensation Committee considered and reviewed the results of the study performed by Longnecker to determine if the results indicated that our compensation programs were yielding a competitive total compensation model prioritizing incentive-based compensation and rewarding achievement of short and long-term performance objectives. The ETP Compensation Committee also specifically evaluated benchmarked results for the annual base salary, annual short-term cash bonus or long-term equity incentive awards of the named executive officers to the compensation levels at the identified “energy peer group” companies and considered Longnecker’s conclusions and recommendations. While Longnecker found that ETP is achieving its stated objectives with respect to the “at-risk” approach, they also found that certain adjustments should be implemented to allow ETP to achieve its targeted percentiles on base compensation and incentive compensation (short and long-term).

Longnecker did not provide any non-executive compensation services for ETP during 2015. In addition to the information received as a result of a periodic engagement of a third party consultant, the ETP Compensation Committee also utilizes information obtained from other sources, such as annual third party surveys, in its determination of compensation levels for our named executive officers.

In respect of Sunoco Logistics, during 2015 Longnecker reviewed various metrics in order to recognize that Sunoco Logistics structure is unique given that (i) in certain respects, Sunoco Logistics operates as significant operational division of ETP; (ii) for certain corporate functions Sunoco Logistics receives certain shared-service support from ETE and ETP; and (iii) in other operational related functions, Sunoco Logistics operates as an independent publicly-traded organization. As such, Longnecker reviewed certain of the executives, including the named executive officers of Sunoco Logistics, in their specific functions to determine the appropriate benchmarking technique. In all circumstances, Longnecker considered Sunoco Logistics annual revenues and market capitalization levels in its benchmarking.

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In conducting its review with respect to Sunoco Logistics' executives that were considered to have roles consistent with those of an executive at an independent publicly-traded entity, Longnecker worked with ETP and Sunoco Logistics to identify a "peer group" of companies in the energy industry that most closely reflect Sunoco Logistics profile in terms of revenues, assets and market value as well as compete with Sunoco Logistics for talent at the senior management level. The identified companies included:

Energy Peer Group:

- Buckeye Partners, L.P.
- Enbridge Energy Partners, L.P.
- HollyFrontier Corporation
- MarkWest Energy Partners, L.P.
- NGL Energy Partners LP
- ONEOK Inc.
- PBF Energy Inc.
- Plains All American Pipeline, L.P.
- Spectra Energy Corp.
- Targa Resources Corp.
- Tesoro Corporation

The compensation analysis provided by Longnecker 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 for certain companies in the oil and gas industry. The compensation committee of the general partner of Sunoco Logistics ("SXL Compensation Committee") utilized the information provided by Longnecker to ensure that the total compensation is both competitive with the market information received and consistent with ETE's compensation philosophy. While Longnecker found that Sunoco Logistics is achieving its stated objectives with respect to the "at-risk" approach, they also found that certain adjustments should be implemented to allow Sunoco Logistics to achieve its targeted percentiles on base compensation and incentive compensation (short and long-term).

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 40^{th} percentile of market) and are determined by the ETP Compensation Committee after taking into account the recommendations of Mr. Warren.

During the 2015 merit review process in July, the ETP Compensation Committee approved an increase to Mr. McCrea of 6.3% to \$850,000 from its prior level of \$800,000; a 12.5% increase to Mr. Long to \$450,000 from its prior level of \$400,000 and a 3.0% increase to Mr. Mason to \$566,500 from its prior level of \$550,000. The ETP Compensation Committee determined that the increases to Messrs. McCrea, Long and Mason were warranted based on the results of the Longnecker study, the factors described below under "Annual Bonus" and, in Mr. Long's case, the increase in duties from his prior role with Regency Energy Partners LP. Mr. Ramsey's base salary of \$625,000, which was effective on his commencement of employment, was approved by the ETP Compensation Committee and set forth in his offer letter. Our CEO (who has voluntarily elected to forgo any base compensation) and Mr. Salinas (who was terminated prior to merit cycle review) did not receive any base salary adjustments during 2015.

In the case of Mr. Hennigan, the SXL Compensation Committee, in consultation with the General Partner, increased his base salary 4.2% to \$625,000 from its previous level of \$600,000; this increase was approved in July 2015. Mr. Hennigan's increase was based principally on the results of the Longnecker review of Sunoco Logistics.

In addition, as reflected in the Compensation Discussion and Analysis of ETE, Mr. McCrea received an additional base compensation increase from \$850,000 to \$1,000,000 in connection with his appointment as Group Chief Operating Officer and Group Chief Commercial Officer of the general partner of ETE in November 2015.

Annual Bonus. In addition to base salary, the ETP Compensation Committee makes a determination whether to award our named executive officers, other than our CEO (who has voluntarily elected to forgo any annual bonuses), discretionary annual cash bonuses following the end of the year under the Bonus Plan.

These discretionary bonuses, if awarded, are intended to reward our named executive officers for the achievement of financial performance objectives during the year for which the bonuses are awarded in light of the contribution of each individual to our profitability and success during such year. The Compensation Committee also considers the recommendation of our CEO in determining the specific annual cash bonus amounts for each of the other named executive officers. The Compensation Committee does not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and the Compensation Committee does not utilize any formulaic approach to determine annual bonuses.

For 2015, annual bonuses awarded to Messrs. McCrea, Ramsey, Long and Mason were determined under the Bonus Plan. The ETP Compensation Committee's evaluation of performance and determination of an overall available bonus pool is based on the

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Partnership's internal earnings target generally based on targeted EBITDA (the "Earnings Target") budget and the performance of each department compared to the applicable departmental budget (with such performance measured based on the specific dollar amount of general and administrative expenses set for each department). The two performance criteria are weighted 75% on the internal Earnings Target budget criteria and 25% on internal department financial budget criteria. Internal Earnings Target is the primary performance factor in determining annual bonuses, while internal department financial budget criteria is considered to ensure that the Partnership is effectively managing general and administrative costs in a prudent manner.

The Partnership's internal financial budgets are generally developed for each business segment, and then aggregated with appropriate corporate level adjustments, to reflect an overall performance objective that is reasonable in light of market conditions and opportunities based on a high level of effort and dedication across all segments of the Partnership's business. The evaluation of the Partnership's performance versus its internal financial budget is based on the Partnership's EBITDA for a calendar year.

In general, the ETP Compensation Committee believes that Partnership performance at or above the internal Earnings Target and at or below internal department financial budgets would support bonuses to our named executive officers ranging from 100% to 125% of their annual base earnings (which amount reflects the actual base salary earned during the calendar year to reflect periods before and after any base salary adjustments). For 2015, in connection with the Longnecker study, the ETP Compensation Committee adjusted the short-term annual cash bonus pool targets for each of the named executive officers. The specific targets are as follows: for Mr. McCrea, 160% of his annual base earnings, which represents an increase from his previous level of 140%, for Mr. Long, 125% of his annual base earnings, which represents an increase from his previous level of 120% and for Mr. Mason, 130% of his annual base earnings, which represents an increase from his previous level of 120%. Mr. Ramsey's target of 140% was approved by the ETP Compensation Committee and set by his initial offer letter.

For 2015 at Sunoco Logistics annual bonuses were determined under the Sunoco Partners LLC Amended and Restated Annual Short-Term Incentive Bonus Plan (the "SXL Bonus Plan"). Mr. Hennigan's target of 140% of his annual base earnings, which represents an increase from his previous target of 135%, was developed and approved by the SXL Compensation Committee of in response to the Longnecker study.

In respect of 2015 performance, in February 2016, the ETP Compensation Committee approved cash bonuses relating to the 2015 calendar year to Messrs. Ramsey and Long in the amounts of $200,000 and $480,296, respectively. In the case of Mr. Ramsey, his bonus amount represents an upward adjustment from his target of $97,175 at the Partnership's 96.25% funding level, based on the Partnership's achievement of 95% of the internal Earnings Target and 100% of the internal department financial budget criteria. Mr. Long's award represents payout at his target bonus based on his annual base earnings at the Partnership's 96.25% funding level.

The ETE Compensation Committee approved a cash bonus relating to the 2015 calendar year to Mr. McCrea in the amount of $1,294,192, representing payout at his target bonus based on the achievement of 95% of the internal Earnings Target and 100% of the internal department financial budget criteria.

With respect to Mr. Mason, in February 2016, the ETE Compensation Committee approved a one-time special incentive retention bonus in the amount of $6,300,000 (the "Special Bonus") of which $697,716 related to his 2015 bonus award under the Bonus Plan. The Special Bonus was approved by the ETE Compensation Committee based on a recommendation of ETE senior management in recognition of, among other things, (i) Mr. Mason's appointment as the Executive Vice President and General Counsel of the general partner of ETE; (ii) his 2015 calendar year performance; and (iii) his contributions to ETE and its family of partnerships on several key initiatives, including (a) the drop-down transactions by and between ETP and Sunoco LP, (b) the proposed merger transaction between the ETE and The Williams Companies, Inc., (c) ETE's liquefied natural gas (LNG) export project, and (d) the simplification of the overall Energy Transfer family structure. The approval of the Special Bonus by the ETE Compensation Committee was conditioned upon entry by Mr. Mason into a Retention Agreement with ETE (the "Retention Agreement") which provides (i) if, prior to the third (3rd) anniversary of the effective date of the Retention Agreement, Mr. Mason's employment with ETE or one of its affiliates terminates (other than as a result of (x) a termination without cause by ETE or by Mr. Mason for Good Reason; (y) his death; or (z) his permanent disability as determined by ETE), he will be obligated to remit and repay one-hundred percent (100%) of the Special Bonus to

ETE; (ii) if, after the third (3rd) anniversary but prior to the fourth (4th) anniversary of the effective date of the Retention Agreement, Mr. Mason's employment with ETE or one of its affiliates terminates (other than as a result of (x) a termination without cause by ETE or by Mr. Mason for Good Reason; (y) his death; or (z) his permanent disability as determined by ETE), he will be obligated to remit and repay seventy-five percent (75%) of the Special Bonus to ETE; and (iii) if, after the fourth (4th) anniversary but prior to the fifth (5th) anniversary of the effective date of the Retention Agreement, Mr. Mason's employment with ETE or one of its affiliates terminates (other than as a result of (x) a termination without cause by ETE or by Mr. Mason for Good Reason; (y) his death; or (z) his permanent disability as determined by ETE), he will be obligated to remit and repay fifty percent (50%) of the Special Bonus to ETE. Mr. Mason and ETE entered into the Retention Agreement on February 24, 2016.

The SXL Compensation Committee approved a cash bonus relating to the 2015 calendar year to Mr. Hennigan in the amount of $856,152, representing a payout at his target bonus amount based on Sunoco Logistics 100% pool funding under the SXL Bonus Plan.

In approving the 2015 bonuses of the named executive officers, the ETE Compensation Committee, the ETP Compensation Committee and the SXL Compensation Committee took into account the achievement by the respective partnerships of all of the targeted performance objectives for 2015 and the individual performances of each of the named executive officers, as well as the Longnecker study results. With respect to the award of the Special Bonus to Mr. Mason, the ETE Compensation Committee took into consideration the factors enumerated as well as the achievement by ETE of all of the targeted performance objectives for 2015, his individual performance and the Longnecker study. The cash bonuses awarded to each of the executive officers for 2015 performance were consistent with their applicable bonus pool targets.

Equity Awards. ETP currently has three incentive plans: (i) the Amended and Restated Energy Transfer Partners, L.P. 2004 Unit Plan (as amended and restated as of June 27, 2007, the "2004 Unit Plan"), (ii) 2008 Incentive Plan and (iii) the Energy Transfer Partners, L.P. Amended and Restated 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"). Each of the 2004 Unit Plan, 2008 Incentive Plan and 2011 Incentive Plan authorizes the ETP Compensation Committee, in its discretion, to grant awards of restricted units, phantom units, unit options and other awards related to our units upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by each such plan. The ETP Compensation Committee determined and/or approved the terms of the unit grants awarded to our named executive officers, including the number of Common Units subject to the restricted unit award and the vesting structure of those restricted unit awards. All of the awards granted to the named executive officers under these equity incentive plans have consisted of restricted unit awards that are subject to vesting over a specified time period. Upon vesting of any restricted unit award, ETP Common Units are issued. During 2015, Mr. Hennigan participated in the Sunoco Partners LLC Long-Term Incentive Plan, as amended, (the "Sunoco Logistics Plan") under which restricted units are awarded, such restricted units have the same vesting terms as awards under the 2008 Incentive Plan.

For 2015, in connection with the Longnecker study, the ETP Compensation Committee in July 2015, approved increased targets for each of the named executive officers. Mr. McCrea's annual long-term incentive target increased from 750% of his annual base salary to 900% of his base salary. In the cases of Messrs. Long and Mason, their annual long-term incentive targets increased to 400% and 500% of their annual base salary, respectively; from their previous levels of 300% and 400%, respectively. Mr. Ramsey's target of 600% was approved by the ETP Compensation Committee and set by his initial offer letter. The SXL Compensation Committee, in consultation with the General Partner, increased Mr. Hennigan's annual long-term target from 500% of his annual base salary to 600% of his base salary in consideration of the Longnecker study.

In December 2015, the ETP Compensation Committee approved grants of restricted unit awards to Messrs. McCrea, Ramsey, Long and Mason of 123,507 units, 77,190 units, 18,525 units and 29,155 units, respectively, under the 2008 Incentive Plan related to ETP Common Units. As described below in the section titled "Subsidiary Equity Awards," for 2015, in discussions between the ETE Compensation Committee and ETP Compensation Committees, as well as, the SXL Compensation Committee and the compensation committees of the general partners of Sunoco LP, it was determined that portions of total long-term incentive award target values of Messrs. McCrea, Long and Mason would be composed of restricted units awarded under the 2008 Incentive Plan as well as restricted/ restricted phantom units under the equity incentive plans of Sunoco Logistics and Sunoco LP in consideration for their roles and responsibilities at those partnerships.

For Mr. McCrea, his total 2015 total long-term incentive awards were allocated approximately 2/3 to the 2008 Incentive Plan and 1/3 to the Sunoco Logistics Plan. At Sunoco Logistics, Mr. McCrea serves as Chairman of the Board of Sunoco Logistics' general partner. For Mr. Mason, his total 2015 long-term awards were allocated 50% to the 2008 Incentive Plan, 25% to Sunoco Logistics Plan and 25% to the Sunoco LP equity plan. Mr. Mason serves on the board of Sunoco Logistics and as a legal advisor in matters related to mergers and acquisitions and financing activities to both Sunoco Logistics and Sunoco LP. For Mr. Long, his total 2015 long-term awards were allocated 50% to the 2008 Incentive Plan, 20% to the Sunoco Logistics Plan and 30% to the Sunoco LP equity plan. Mr. Long serves as a financial advisor in matters related to mergers and acquisitions and financing activities to both Sunoco Logistics and Sunoco LP.

It is expected that future long-term incentive awards to the named executive officers of the Partnership and ETE will recognize a similar aggregation of restricted/phantom restricted units under long-term incentive plans of the Partnership, Sunoco Logistics and/or Sunoco LP, as applicable. The terms and conditions of the restricted unit awards to Messrs. McCrea, Long and Mason under the Sunoco Logistics and Sunoco LP equity incentive plans are identical to the terms and conditions of the restricted unit awards under the 2008 Incentive Plan applicable to Messrs. McCrea, Long and Mason.

The restricted unit awards provide for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, generally subject to continued employment through each specified vesting date. The restricted unit awards entitle the recipients of the restricted unit awards to receive, with respect to each ETP Common Unit

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subject to such award that has not either vested or been forfeited, a DER cash payment promptly following each such distribution by us to our Unitholders. In approving the grant of such restricted unit awards, the Compensation Committee took into account the same factors as discussed above under the caption “Annual Bonus,” the long-term objective of retaining such individuals as key drivers of the Partnership’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 2014 and 2015 awards would accelerate in the event of the death or disability of the named executive officer or in the event of a change in control of the Partnership as that term is defined under the 2008 Incentive Plan. In the case of Mr. Hennigan, he received a long-term incentive awards under the Sunoco Logistics Plan for 2015. The award of 116,750 restricted units was awarded by the SXL Compensation Committee. This award was awarded on identical terms and conditions with respect to vesting and the right to DER payments, as those awarded to Messrs. McCrea, Long and Mason under the 2008 Incentive Plan in 2015.

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

The restricted unit awards under the 2008 Incentive Plan as well as awards under the Sunoco Logistics and Sunoco LP equity incentive plans generally require the continued employment of the recipient during the vesting period, provided however, the unvested awards will be accelerated in the event of a change in control of the applicable partnership or the death or disability of the award recipient prior to the applicable vesting period being satisfied. In addition, in the event of a change in control of ETP, all unvested awards granted under the 2004 Unit Plan, as well as awards granted in 2014 and 2015 under the 2008 Incentive Plan and the 2011 Incentive Plan, as applicable, would be accelerated. For awards previously granted under the 2008 Incentive Plan prior to December 2014, unvested awards may also become vested upon a change in control at the discretion of the Compensation Committee. Under the Sunoco Logistics and Sunoco LP equity incentive plans, awards granted in 2014 and 2015 would be accelerated in the event of a change in control of the applicable partnership.

The ETP Compensation Committee or the compensation committees of one of the affiliated partnerships has in the past and may in the future, but is not required to, accelerate the vesting of unvested restricted unit awards in the event of the termination or retirement of an executive officer. The ETP Compensation Committee accelerated the vesting of 61,841 ETP restricted unit awards and the SXL Compensation Committee accelerated the vesting of 32,600 Sunoco Logistics restricted unit awards, with realized vesting values of $3,505,828 and $1,347,358, respectively, upon the resignation of Mr. Salinas. The ETP Compensation Committee did not accelerate the vesting of restricted unit awards to any other named executive officers in 2015.

As discussed below under “Potential Payments Upon a Termination or Change of Control,” certain equity awards 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 2015 award to Mr. Ramsey in accordance with the terms of his offer letter, the 2014 awards to Mr. McCrea and the 2014 award to Mr. Hennigan included a provision in the applicable award agreement for acceleration of unvested restricted unit awards upon a termination of employment without “cause” by the general partner of the applicable partnership issuing the award. For purposes of the awards the term “cause” shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the partnership or any of its or their affiliates by, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the partnership or any of its or their affiliate.

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.

Unit Ownership Guidelines. In December 2013, the Board of Directors adopted the ETP Executive Unit Ownership Guidelines (the “Guidelines”), which set forth minimum ownership guidelines applicable to certain executives of the Partnership with respect to Common Units representing limited partnership interests in the Partnership. The applicable unit ownership 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 Operating Officer is 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 our 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 Guidelines do not apply to our CEO, who receives a salary of $1.00 per year plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits.

Our General Partner and the Compensation Committee believe that the ownership of our Common Units, as reflected in the Guidelines, is an important means of tying the financial risks and rewards for our executives to our total unitholder return, aligning the interests of such executives with those of our Unitholders, and promoting the Partnership's interest in good corporate governance.

Covered executives are generally required to achieve their ownership level within five years of becoming subject to the guidelines; however, certain covered executives, based on their tenure as an executive, are required to achieve compliance within two years of the December 2013 effective date of the Guidelines. Thus, compliance with the Guidelines was required for Messrs. McCrea and Mason beginning December 2015 and both are compliant. Mr. Ramsey will be required to be compliant with the Guidelines in November 2020 and Tom Long beginning December 2018.

Covered executives may satisfy the guidelines through direct ownership of Common Units or indirect ownership by certain immediate family members. Direct or indirect ownership of ETE, Sunoco Logistics and 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.

Covered executives 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 guideline may dispose of our 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 guideline.

Affiliate and Subsidiary Equity Awards. In addition to their roles as officers of our General Partner, Messrs. McCrea serves as an officer and director of the general partner of Sunoco Logistics, Mr. Mason serves as a director of the general partner of Sunoco Logistics and provides certain legal services to the general partners of Sunoco Logistics and Sunoco LP and Mr. Long provides certain financial services to the general partners of Sunoco Logistics and Sunoco LP. In connection with those roles at Sunoco Logistics, in December 2015, the SXL Compensation Committee awarded Messrs. McCrea, Long and Mason time-based restricted units of Sunoco Logistics in the amount of 93,390 units, 11,208 units and 22,046 units, respectively. In connection with those roles at Sunoco LP, in December 2015, the compensation committee of Sunoco LP's general partner awarded Messrs. Long and Mason time-based restricted units of Sunoco LP in the amount of 14,125 units and 18,523 units, respectively. The terms and conditions of the restricted unit awards to Messrs. McCrea, Long and Mason under the Sunoco Logistics and Sunoco LP equity plans are identical to the terms and conditions of the restricted unit awards under our equity plan applicable to Messrs. McCrea, Long and Mason.

Qualified Retirement Plan Benefits. The Energy Transfer Partners GP, L.P. 401(k) Plan (the "ETP 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 our 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. Our 2004 Unit Plan provides for immediate vesting of all unvested restricted unit awards in the event of a change in control, as defined in the applicable plan. In addition, our 2008 Incentive Plan and 2011 Incentive Plan provide the Compensation Committee with the discretion, unless otherwise specified in the applicable award agreement, to provide for immediate vesting of all unvested restricted unit awards in the event of (i) a change of control, as defined in the plan; (ii) death or (iii) disability, as defined in the applicable plan. In the case of the December 2014 and 2015 long-term incentive awards to the named executive officers under the 2008

Incentive Plan or as applicable the equity incentive plan of Sunoco Logistics and Sunoco LP, the awards would immediately and fully vest all unvested restricted unit awards in the event of a change of control, 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, our General Partner has also adopted the ETP GP Severance Plan and Summary Plan Description effective as of June 12, 2013, (the "Severance Plan"), which provides for payment of certain severance benefits in the event of Qualifying Termination (as that term is defined in the Severance Plan). In general, the Severance Plan provides payment of two weeks of annual base salary for each year or partial year of employment service with the Partnership up to a maximum of fifty-two weeks or one year of annual base salary (with a minimum of four weeks of annual base salary) and up to three months of continued group health insurance coverage. The Severance Plan also provides that the Partnership 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.

ETP Deferred Compensation Plan. We maintain a deferred compensation plan ("DC Plan"), which permits eligible highly compensated employees to defer a portion of their salary and/or bonus until retirement or termination of employment or other designated distribution. Under the DC Plan, each year eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested unit distribution income, and/or 50% of their discretionary performance bonus compensation to be earned for services performed during the following year. Pursuant to the DC Plan, ETP may make annual discretionary matching contributions to participants' accounts; however, we have not made any discretionary contributions to participants' accounts and currently have no plans to make any discretionary contributions to participants' accounts. All amounts credited under the DC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings or losses based on hypothetical investment fund choices made by the participants among available funds.

Participants may elect to have their accounts distributed in one lump sum payment or in annual installments over a period of three or five years upon retirement, and in a lump sum upon other termination. Participants may also elect to take lump-sum in-service withdrawals five years or longer in the future, and such scheduled in-service withdrawals may be further deferred prior to the withdrawal date. Upon a change in control (as defined in the DC Plan) of ETP, all DC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the DC Plan's normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement.

ETP Deferred Compensation Plan for Former Sunoco Executives. The ETP Deferred Compensation Plan for Former Sunoco Executives ("Sunoco DC Plan") is a deferred compensation plan established by ETP in connection with the ETP's acquisition of Sunoco Logistics. In 2012, Mr. Hennigan waived any future rights or benefits to which he otherwise would have been entitled under both the Sunoco, Inc. Executive Retirement Plan ("SERP"), a non-qualified, unfunded plan that provided supplemental pension benefits over and above the benefits under the Sunoco, Inc. Retirement Plan ("SCIRP"), a qualified defined benefit plan sponsored by Sunoco, Inc., under which benefits are subject to IRS limits for pay and amount, and Sunoco Logistics' pension restoration plan, in return for which, $2,789,413 of such deferred compensation benefits was credited to Mr. Hennigan's account under this plan. Mr. Hennigan is our only executive officer eligible to participate in the Sunoco DC Plan. Mr. Hennigan's account is 100 percent vested and will be distributed in one lump sum payment upon his retirement or termination of employment, or other designated distribution event, including a change of control (as defined in the Sunoco DC Plan). His account is credited with deemed earnings (or losses) based on hypothetical investment fund choices made by him among available funds.

Risk Assessment Related to our Compensation Structure. We believe our 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 the Partnership. We believe our 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 our 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 the 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 an operating segment. We generally determine whether, and to what extent, our named executive officers receive a cash bonus based on our achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership's success. We use restricted units rather than unit options for equity awards because restricted units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options "in-the-money." Finally, the time-based vesting over five years for our long-term incentive awards ensures that our employees' interests align with those of our Unitholders for the long-term performance of the Partnership.

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Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for U.S. federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore is generally fully deductible for U.S. federal income tax purposes.

Accounting for Unit-Based Compensation

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

Compensation Committee Interlocks and Insider Participation

Messrs. Grimm and Skidmore are the only members of the Compensation Committee. During 2015, no member of the Compensation Committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company's board of directors. In addition, neither Mr. Grimm nor Mr. Skidmore is a former employee of ours or any of our subsidiaries.

Report of Compensation Committee

The Compensation Committee of the board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management of ETP. Based on this review and discussion, we have recommended to the board of directors of our General Partner that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

The Compensation Committee of the
Board of Directors of Energy Transfer Partners, L.L.C., the
general partner of Energy Transfer Partners GP, L.P., the
general partner of Energy Transfer Partners, L.P.
Michael K. Grimm
David K. Skidmore

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.

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Compensation Tables
Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus [1] ($)	Equity Awards [2] ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings [3] ($)	All Other Compensation [4] ($)	Total ($)
Kelcy L. Warren [5]	2015	$6,338	$—	$—	$—	$ —	$ —	$—	$6,338
Chief Executive	2014	6,921	—	—	—	—	—	—	6,921
Officer	2013	5,814	—	—	—	—	—	—	5,814
Thomas E. Long	2015	399,207	480,296	1,447,063	—	—	—	14,282	2,340,848
Chief Financial	2014	326,221	391,465	777,850	—	—	—	14,032	1,509,568
Officer	2013	322,700	322,700	682,551	—	—	—	13,822	1,341,773
Martin Salinas, Jr.	2015	189,230	—	—	—	—	—	4,368,588	4,557,818
Former Chief	2014	455,625	546,750	1,345,143	—	—	15,468	21,795	2,384,781
Financial Officer	2013	437,019	524,423	1,861,698	—	—	56,036	26,136	2,905,312
Matthew S. Ramsey [6]	2015	72,115							