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Energy Transfer Partners, L.P.
Form 10-K
February 29, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 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
Common Units
Name of each exchange on which registered
New York Stock Exchange

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

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

Yes No

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

Yes No

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

Yes No

Indicate by check mark whether the registrant has submitted electronically 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 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 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

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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 |

| | |
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| 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

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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, Cayanosa, 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 addition to crude oil service, the Eagle Point terminal can accommodate three marine vessels (ships or barges) to receive and deliver refined products to outbound ships and barges. The tank farm has a total active refined products storage capacity of approximately 6 million barrels, and provides customers with access to the facility via barge, 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

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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 EPCRA 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 (“HLPESA”), with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPESA 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 HLPESA, 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

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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.

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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

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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.

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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 domain 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 than we do.