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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2017

or

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

Commission file number 1-31219

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)

(214) 981-0700
(Registrant's telephone number, including area code)

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 (§232.405 of this chapter) 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐
		Emerging growth company	☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

At November 3, 2017, the registrant had 1,155,493,524 Common Units outstanding.

FORM 10-Q

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

TABLE OF CONTENTS

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (the “Partnership” or “ETP”) in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “estimate,” “goal,” “forecast,” “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its general partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership’s actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Part I – Item 1A. Risk Factors” in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2016 filed with the Securities and Exchange Commission on February 24, 2017 and Exhibit 99.3 to the Partnership’s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2017.

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)
AROs	asset retirement obligations
Bbls	barrels
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
CrossCountry	CrossCountry Energy, LLC
DOJ	U.S. Department of Justice
ETC Compression	ETC Compression, LLC
EPA	Environmental Protection Agency
ETC FEP	ETC Fayetteville Express Pipeline, LLC
ETC MEP	ETC Midcontinent Express Pipeline, L.L.C.
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETC Tiger	ETC Tiger Pipeline, LLC
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC for the periods presented herein
ET Interstate	Energy Transfer Interstate Holdings, LLC
ET Rover	ET Rover Pipeline LLC
ETLP Credit Facility	Energy Transfer, LP’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
ExxonMobil	Exxon Mobil Corporation
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
HPC	RIGS Haynesville Partnership Co. and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	incentive distribution rights
LIBOR	London Interbank Offered Rate
MEP	Midcontinent Express Pipeline LLC
MBbls	thousand barrels
MMBtu	million British thermal units
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	polychlorinated biphenyls
PennTex	PennTex Midstream Partners, LP
PES	Philadelphia Energy Solutions, a refining joint venture
Preferred Units	ETP Series A cumulative convertible preferred units
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, LLC, a wholly-owned subsidiary of Sunoco, Inc.
Rover	Rover Pipeline LLC, a subsidiary of ETP
Sea Robin	Sea Robin Pipeline Company, LLC, a subsidiary of Panhandle
SEC	Securities and Exchange Commission
Sunoco Logistics	Sunoco Logistics Partners L.P.
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle

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

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 379	$ 360
Accounts receivable, net	3,083	3,002
Accounts receivable from related companies	335	209
Inventories	1,591	1,712
Income taxes receivable	151	128
Derivative assets	40	20
Other current assets	201	298
Total current assets	5,780	5,729
Property, plant and equipment	65,735	58,220
Accumulated depreciation and depletion	(8,763)	(7,303)
	56,972	50,917
Advances to and investments in unconsolidated affiliates	4,221	4,280
Other non-current assets, net	752	672
Intangible assets, net	5,379	4,696
Goodwill	3,907	3,897
Total assets	$ 77,011	$ 70,191

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

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

	September 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,410	$ 2,900
Accounts payable to related companies	204	43
Derivative liabilities	128	166
Accrued and other current liabilities	2,434	1,905
Current maturities of long-term debt	710	1,189
Total current liabilities	6,886	6,203
Long-term debt, less current maturities	33,630	31,741
Long-term notes payable – related company	—	250
Non-current derivative liabilities	132	76
Deferred income taxes	4,374	4,394
Other non-current liabilities	1,111	952
Commitments and contingencies		
Preferred Units	—	33
Redeemable noncontrolling interests	21	15
Equity:		
General Partner	252	206
Limited Partners:		
Common Unitholders	26,400	14,946
Class H Unitholder	—	3,480
Class I Unitholder	—	2
Accumulated other comprehensive income	14	8
Total partners' capital	26,666	18,642
Noncontrolling interest	4,191	7,885
Total equity	30,857	26,527
Total liabilities and equity	$ 77,011	$ 70,191

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
REVENUES:				
Natural gas sales	$ 1,098	$ 1,069	$ 3,132	$ 2,602
NGL sales	1,750	1,249	4,782	3,339
Crude sales	2,273	1,649	6,751	4,572
Gathering, transportation and other fees	1,027	986	3,118	2,991
Refined product sales	334	177	1,109	656
Other	491	401	1,552	1,141
Total revenues	6,973	5,531	20,444	15,301
COSTS AND EXPENSES:				
Cost of products sold	4,876	3,844	14,582	10,280
Operating expenses	571	475	1,603	1,359
Depreciation, depletion and amortization	596	503	1,713	1,469
Selling, general and administrative	105	71	335	226
Total costs and expenses	6,148	4,893	18,233	13,334
OPERATING INCOME	825	638	2,211	1,967
OTHER INCOME (EXPENSE):				
Interest expense, net	(367)	(345)	(1,052)	(981)
Equity in earnings of unconsolidated affiliates	127	65	139	260
Impairment of investment in an unconsolidated affiliate	—	(308)	—	(308)
Losses on interest rate derivatives	(8)	(28)	(28)	(179)
Other, net	72	52	169	96
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	649	74	1,439	855
Income tax expense (benefit)	(112)	(64)	22	(131)
NET INCOME	761	138	1,417	986
Less: Net income attributable to noncontrolling interest	110	64	243	231
NET INCOME ATTRIBUTABLE TO PARTNERS	651	74	1,174	755
General Partner's interest in net income	270	220	727	740
Class H Unitholder's interest in net income	—	93	98	257
Class I Unitholder's interest in net income	—	2	—	6
Common Unitholders' interest in net income (loss)	$ 381	$ (241)	$ 349	$ (248)
NET INCOME (LOSS) PER COMMON UNIT:				
Basic	$ 0.33	$ (0.33)	$ 0.35	$ (0.36)
Diluted	$ 0.33	$ (0.33)	$ 0.34	$ (0.36)

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income	$ 761	$ 138	$ 1,417	$ 986
Other comprehensive income (loss), net of tax:				
Change in value of available-for-sale securities	2	—	5	5
Actuarial gain (loss) relating to pension and other postretirement benefit plans	5	—	2	(3)
Foreign currency translation adjustments	—	—	—	(1)
Change in other comprehensive income from unconsolidated affiliates	—	2	(1)	(9)
	7	2	6	(8)
Comprehensive income	768	140	1,423	978
Less: Comprehensive income attributable to noncontrolling interest	110	64	243	231
Comprehensive income attributable to partners	$ 658	$ 76	$ 1,180	$ 747

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2017
(Dollars in millions)
(unaudited)

		Limited Partners					
	General Partner	Common Units	Class H Units	Class I Units	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
Balance, December 31, 2016	$ 206	$ 14,946	$ 3,480	$ 2	$ 8	$ 7,885	$ 26,527
Distributions to partners	(681)	(1,765)	(95)	(2)	—	—	(2,543)
Distributions to noncontrolling interest	—	—	—	—	—	(306)	(306)
Units issued for cash	—	2,162	—	—	—	—	2,162
Sunoco Logistics Merger	—	9,459	(3,483)	—	—	(5,976)	—
Capital contributions from noncontrolling interest	—	—	—	—	—	1,907	1,907
Sale of Bakken Pipeline interest	—	1,260	—	—	—	740	2,000
Acquisition of PennTex noncontrolling interest	—	(48)	—	—	—	(232)	(280)
Other comprehensive income, net of tax	—	—	—	—	6	—	6
Other, net	—	37	—	—	—	(70)	(33)
Net income	727	349	98	—	—	243	1,417
Balance, September 30, 2017	$ 252	$ 26,400	$ —	$ —	$ 14	$ 4,191	$ 30,857

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

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

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES		
Net income	$ 1,417	$ 986
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,713	1,469
Deferred income taxes	(1)	(154)
Amortization included in interest expense	5	(16)
Inventory valuation adjustments	(30)	(143)
Unit-based compensation expense	57	60
Impairment of investment in an unconsolidated affiliate	—	308
Distributions on unvested awards	(21)	(19)
Equity in earnings of unconsolidated affiliates	(139)	(260)
Distributions from unconsolidated affiliates	319	292
Other non-cash	(168)	(230)
Net change in operating assets and liabilities, net of effects of acquisition	185	172
Net cash provided by operating activities	3,337	2,465
INVESTING ACTIVITIES		
Proceeds from Bakken Pipeline Transaction	2,000	—
Proceeds from the Sunoco, Inc. retail business to Sunoco LP transaction	—	2,200
Cash paid for acquisition of PennTex noncontrolling interest	(280)	—
Cash paid for all other acquisitions	(264)	(159)
Capital expenditures, excluding allowance for equity funds used during construction	(6,074)	(5,787)
Contributions in aid of construction costs	18	44
Contributions to unconsolidated affiliates	(230)	(47)
Distributions from unconsolidated affiliates in excess of cumulative earnings	116	112
Proceeds from the sale of assets	33	6
Change in restricted cash	—	(8)
Other	(6)	(1)
Net cash used in investing activities	(4,687)	(3,640)
FINANCING ACTIVITIES		
Proceeds from borrowings	19,978	13,073
Repayments of long-term debt	(18,487)	(11,308)
Cash paid to affiliate notes	(255)	(1)
Units issued for cash	2,162	794
Subsidiary units issued for cash	—	1,305
Capital contributions from noncontrolling interest	919	187
Distributions to partners	(2,543)	(2,669)
Distributions to noncontrolling interest	(306)	(334)
Redemption of Preferred Units	(53)	—
Debt issuance costs	(50)	(22)
Other	4	—
Net cash provided by financing activities	1,369	1,025
Increase (decrease) in cash and cash equivalents	19	(150)
Cash and cash equivalents, beginning of period	360	527
Cash and cash equivalents, end of period	$ 379	$ 377

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

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

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Energy Transfer Partners, L.P. (“ETP”, formerly named “Sunoco Logistics Partners L.P.”, as discussed below) is a consolidated subsidiary of ETE.

In April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed a merger transaction (the “Sunoco Logistics Merger”) in which Sunoco Logistics acquired Energy Transfer Partners, L.P. in a unit-for-unit transaction. Prior to the Sunoco Logistics Merger, Sunoco Logistics was a consolidated subsidiary of Energy Transfer Partners, L.P. Under the terms of the transaction, the unitholders received 1.5 common units of Sunoco Logistics for each Energy Transfer Partners, L.P. common unit they owned. Under the terms of the merger agreement, Sunoco Logistics’ general partner was merged with and into ETP GP, with ETP GP surviving as an indirect wholly-owned subsidiary of ETE. Based on the number of Energy Transfer Partners, L.P. common units outstanding at the closing of the merger, Sunoco Logistics issued approximately 832 million Sunoco Logistics common units to Energy Transfer Partners, L.P. unitholders. In connection with the merger, the Energy Transfer Partners, L.P. Class H units were cancelled. The outstanding Energy Transfer Partners, L.P. Class E units, Class G units, Class I units and Class K units at the effective time of the merger were converted into an equal number of newly created classes of Sunoco Logistics units, with the same rights, preferences, privileges, duties and obligations as such classes of Energy Transfer Partners, L.P. units had immediately prior to the closing of the merger. Additionally, the outstanding Sunoco Logistics common units and Sunoco Logistics Class B units owned by Energy Transfer Partners, L.P. at the effective time of the merger were cancelled.

At the time of the Sunoco Logistics Merger, Energy Transfer Partners, L.P. changed its name from “Energy Transfer Partners, L.P.” to “Energy Transfer, LP” and Sunoco Logistics Partners L.P. changed its name to “Energy Transfer Partners, L.P.” For purposes of maintaining clarity, the following references are used herein:

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

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

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

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

The consolidated financial statements of the Partnership presented herein include our operating subsidiaries (collectively, the “Operating Companies”), through which our activities are primarily conducted, as follows:

- ETC OLP, Regency and PennTex, which are primarily engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP and Regency own and operate, through their wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and are engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, West Virginia, Denver and Ohio.

- ET Interstate, with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
  - Transwestern, engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
  - ETC FEP, which directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
  - ETC Tiger, engaged in interstate transportation of natural gas.
  - CrossCountry, which indirectly owns a 50% interest in Citrus, which owns 100% of the FGT interstate natural gas pipeline.
  - ETC MEP, which directly owns a 50% interest in MEP.
  - ET Rover, which owns a 65% interest in Rover pipeline.
- ETC Compression, LLC, engaged in natural gas compression services and related equipment sales.
- ETP Holdco, which indirectly owns Panhandle and Sunoco, Inc. Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States. Sunoco, Inc. owned and operated retail marketing assets, which were contributed to Sunoco LP in March 2016. Subsequent to this transaction, Sunoco Inc.'s assets primarily consist of its ownership in Retail Holdings, which owns noncontrolling interests in Sunoco LP and PES. Subsequent to the Sunoco Logistics Merger, ETLP holds an equity method investment in ETP through ETP Holdco's ownership of ETP Class E, Class G, and Class K units, which investment is eliminated in the consolidated financial statements.
- Sunoco Logistics Partners Operations L.P., which owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets, which are used to facilitate the purchase and sale of crude oil, NGLs and refined products.

Subsequent to the Sunoco Logistics Merger, our financial statements reflect the following reportable business segments:

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

Prior periods have been retrospectively adjusted to reflect the impact of the Sunoco Logistics Merger on our reportable business segments.

Basis of Presentation

The unaudited financial information included in this Form 10-Q has been prepared on the same basis as the audited consolidated financial statements of Energy Transfer Partners, L.P. for the year ended December 31, 2016, included in Exhibit 99.1 to the Partnership's Current Report on Form 8-K filed on August 14, 2017. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

For prior periods reported herein, certain transactions related to the business of legacy Sunoco Logistics have been reclassified from cost of products sold to operating expenses; these transactions include sales between operating subsidiaries and their marketing affiliates. These reclassifications had no impact on net income or total equity.

Use of Estimates

The unaudited consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions made by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the consolidated financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Recent Accounting Pronouncements

ASU 2014-09

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The Partnership expects to adopt ASU 2014-09 in the first quarter of 2018 and will apply the cumulative catchup transition method, which requires recognition, upon the date of initial application, of the cumulative effect of the retrospective application of the standard.

We are continuing the process of evaluating our revenue contracts by segment and fee type to determine the potential impact of adopting the new standard. At this point in our evaluation process, we have determined that the timing and/or amount of revenue that we recognize on certain contracts (as discussed below) may be impacted by the adoption of the new standard; however, we are still in the process of quantifying these impacts and cannot say whether or not they would be material to our financial statements.

We currently anticipate a change to revenues and costs associated with the accounting for noncash consideration in multiple of our reportable segments as well as the accounting for certain processing contracts in our midstream segment. We do not expect these changes in the accounting for noncash consideration or processing contracts to impact net income.

We are still evaluating the potential impact of the adoption of ASU 2014-09 to contributions in aid of construction costs ("CIAC") arrangements and materiality of any related changes. While we do not expect any impacts to net income from the application of the standard to other transactions, we have not concluded whether the application of the standard to CIAC transactions could impact net income.

We continue to assess the impact of the disclosure requirements under the new standard and are evaluating the manner in which we will disaggregate revenue into categories that show how economic factors affect the nature, timing and uncertainty of revenue and cash flows generated from contracts with customers. In addition, we are in the process of implementing appropriate changes to our business processes, systems and controls to support recognition and disclosure under the new standard. We continue to monitor additional authoritative or interpretive guidance related to the new standard as it becomes available, as well as comparing our conclusions on specific interpretative issues to other peers in our industry, to the extent that such information is available to us.

ASU 2016-02

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

ASU 2016-09

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

ASU 2016-16

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

ASU 2016-17

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

ASU 2017-04

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

ASU 2017-12

In August 2017, the FASB issued ASU No. 2017-12 "*Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.*" The amendments in this update improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition, the amendments in this update make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP. This ASU is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. The Partnership is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

2. ACQUISITIONS AND CONTRIBUTION TRANSACTIONS

Rover Contribution Agreement

In July 2017, ETP announced that it had entered into a contribution agreement with a fund managed by Blackstone Energy Partners and Blackstone Capital Partners ("Blackstone"), for the purchase by Blackstone of a 49.9% interest in the holding company that owns 65% of the Rover pipeline ("Rover Holdco"). The agreement with Blackstone required Blackstone to contribute, at closing, funds to reimburse ETP for its pro rata share of the Rover construction costs incurred by ETP through the closing date, along with the payment of additional amounts subject to certain adjustments. The transaction closed in October 2017. As a result of this closing, Rover Holdco is now owned 50.1% by ETP and 49.9% by Blackstone.

Permian Express Partners

In February 2017, Sunoco Logistics formed Permian Express Partners LLC ("PEP"), a strategic joint venture with ExxonMobil. Sunoco Logistics contributed its Permian Express 1, Permian Express 2, Permian Longview and Louisiana Access pipelines. ExxonMobil contributed its Longview to Louisiana and Pegasus pipelines, Hawkins gathering system, an idle pipeline in southern Oklahoma, and its Patoka, Illinois terminal. Assets contributed to PEP by ExxonMobil were reflected at fair value on the Partnership's consolidated balance sheet at the date of the contribution, including $547 million of intangible assets and $435 million of property, plant and equipment.

In July 2017, the Partnership contributed an approximate 15% ownership interest in Dakota Access, LLC ("Dakota Access") and Energy Transfer Crude Oil Company, LLC ("ETCO") to PEP, which resulted in an increase in the Partnership's ownership interest in PEP to approximately 88%. The Partnership maintains a controlling financial and voting interest in PEP and is the operator of all of the assets. As such, PEP is reflected as a consolidated subsidiary of the Partnership. ExxonMobil's interest in PEP is reflected as noncontrolling interest in the consolidated balance sheets. ExxonMobil's contribution resulted in an increase of $988 million in noncontrolling interest, which is reflected in “Capital contributions from noncontrolling interest” in the consolidated statement of equity.

3. CASH AND CASH EQUIVALENTS

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

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

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

	Nine Months Ended September 30,	
	2017	2016
Accounts receivable	$ (77)	$ (595)
Accounts receivable from related companies	46	80
Inventories	150	(299)
Other current assets	37	(135)
Other non-current assets, net	(89)	(1)
Accounts payable	96	635
Accounts payable to related companies	(11)	24
Accrued and other current liabilities	(26)	213
Other non-current liabilities	57	31
Derivative assets and liabilities, net	2	219
Net change in operating assets and liabilities, net of effects of acquisitions	$ 185	$ 172

Non-cash investing and financing activities are as follows:

	Nine Months Ended September 30,	
	2017	2016
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 1,236	$ 991
Sunoco LP limited partner interest received in exchange for contribution of the Sunoco, Inc. retail business to Sunoco LP	—	194
Net gains from subsidiary common unit issuances	—	34
NON-CASH FINANCING ACTIVITIES:		
Contribution of property, plant and equipment from noncontrolling interest	$ 988	$ —

4. INVENTORIES

Inventories consisted of the following:

	September 30, 2017	December 31, 2016
Natural gas and NGLs	$ 609	$ 699
Crude oil	696	683
Refined products	69	113
Spare parts and other	217	217
Total inventories	$ 1,591	$ 1,712

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

5. FAIR VALUE MEASURES

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations as of September 30, 2017 were $35.89 billion and $34.34 billion, respectively. As of December 31, 2016, the aggregate fair value and carrying amount of our consolidated debt obligations were $33.85 billion and $32.93 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the nine months ended September 30, 2017, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the gross fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of September 30, 2017 and December 31, 2016 based on inputs used to derive their fair values:

		Fair Value Measurements at September 30, 2017	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 16	$ 16	$ —
Swing Swaps IFERC	2	—	2
Fixed Swaps/Futures	28	28	—
Forward Physical Swaps	3	—	3
Power:			
Forwards	11	—	11
Futures	1	1	—
Options – Puts	1	1	—
Natural Gas Liquids – Forwards/Swaps	213	213	—
Refined Products – Futures	2	2	—
Crude – Futures	2	2	—
Total commodity derivatives	279	263	16
Total assets	$ 279	$ 263	$ 16
Liabilities:			
Interest rate derivatives	$ (210)	$ —	$ (210)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(22)	(22)	—
Swing Swaps IFERC	(3)	(1)	(2)
Fixed Swaps/Futures	(22)	(22)	—
Forward Physical Swaps	(1)	—	(1)
Power:			
Forwards	(9)	—	(9)
Futures	(1)	(1)	—
Natural Gas Liquids – Forwards/Swaps	(261)	(261)	—
Refined Products – Futures	(2)	(2)	—
Crude – Futures	(1)	(1)	—
Total commodity derivatives	(322)	(310)	(12)
Total liabilities	$ (532)	$ (310)	$ (222)

Table of Contents

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

6. NET INCOME (LOSS) PER LIMITED PARTNER UNIT

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

Net income for partners' capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to the General Partner, the holder of the IDRs pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

A reconciliation of net income (loss) and weighted average units used in computing basic and diluted net income (loss) per unit is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net income	$ 761	$ 138	$ 1,417	$ 986
Less: Income attributable to noncontrolling interest	110	64	243	231
Net income, net of noncontrolling interest	651	74	1,174	755
General Partner's interest in net income	270	220	727	740
Class H Unitholder's interest in net income	—	93	98	257
Class I Unitholder's interest in net income	—	2	—	6
Common Unitholders' interest in net income (loss)	381	(241)	349	(248)
Additional (earnings) distributions allocated to General Partner	—	(3)	12	(9)
Distributions on employee unit awards, net of allocation to General Partner	(6)	(5)	(19)	(15)
Net income (loss) available to Common Unitholders	$ 375	$ (249)	$ 342	$ (272)
Weighted average Common Units – basic [1]	1,125.2	761.1	990.9	749.7
Basic net income (loss) per Common Unit	$ 0.33	$ (0.33)	$ 0.35	$ (0.36)
Dilutive effect of unvested employee unit awards	3.7	—	4.6	—
Weighted average Common Units – diluted [1]	1,128.9	761.1	995.5	749.7
Diluted net income (loss) per Common Unit	$ 0.33	$ (0.33)	$ 0.34	$ (0.36)

(1) Excludes Common Units owned by the Partnership's consolidated subsidiaries.

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

7. DEBT OBLIGATIONS

ETP Senior Notes Redemption

In October 2017, the Partnership redeemed all of the outstanding $500 million aggregate principal amount of ETLP's 6.50% senior notes due July 2021 and all of the outstanding $700 million aggregate principal amount of ETLP's 5.50% senior notes due April 2023. The aggregate amount paid to redeem these notes, including call premiums, was approximately $1.23 billion.

ETP Senior Notes Offering

In September 2017, Sunoco Logistics Partners Operations L.P., a subsidiary of ETP, issued $750 million aggregate principal amount of 4.00% senior notes due 2027 and $1.50 billion aggregate principal amount of 5.40% senior notes due 2047. The $2.22 billion net proceeds from the offering were used to redeem all of the $500 million aggregate principal amount of ETLP's 6.5% senior notes due 2021, to repay borrowings outstanding under the Sunoco Logistics Credit Facility (described below) and for general partnership purposes.

The senior notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the senior notes. The principal is payable upon maturity. Interest on the senior notes is paid semi-annually. The senior notes are guaranteed by the parent company (ETP) on a senior unsecured basis as long as it guarantees any of Sunoco Logistics Partners Operations L.P.'s other long-term debt. As a result of the parent guarantee, the senior notes will rank equally in right of payment with the Partnership's existing and future senior debt, and senior in right of payment to any subordinated debt the Partnership may incur.

Credit Facilities and Commercial Paper

ETLP Credit Facility

The ETLP Credit Facility allows for borrowings of up to $3.75 billion and matures in November 2019. The indebtedness under the ETLP Credit Facility is unsecured, is not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. In September 2016, ETLP initiated a commercial paper program under the borrowing limits established by the $3.75 billion ETLP Credit Facility. As of September 30, 2017, the ETLP Credit Facility had $2.06 billion of outstanding borrowings, all of which was commercial paper.

Sunoco Logistics Credit Facilities

ETP maintains the Sunoco Logistics $2.50 billion unsecured revolving credit facility (the "Sunoco Logistics Credit Facility"), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $3.25 billion under certain conditions. As of September 30, 2017, the Sunoco Logistics Credit Facility had $35 million of outstanding borrowings.

In December 2016, Sunoco Logistics entered into an agreement for a 364-day maturity credit facility ("364-Day Credit Facility"), due to mature on the earlier of the occurrence of the Sunoco Logistics Merger or in December 2017, with a total lending capacity of $1.00 billion. In connection with the Sunoco Logistics Merger, the 364-Day Credit Facility was terminated and repaid in May 2017.

Bakken Credit Facility

In August 2016, Energy Transfer Partners, L.P., Sunoco Logistics and Phillips 66 completed project-level financing of the Bakken Pipeline. The $2.50 billion credit facility provides substantially all of the remaining capital necessary to complete the projects. As of September 30, 2017, $2.50 billion was outstanding under this credit facility.

PennTex Revolving Credit Facility

PennTex previously maintained a $275 million revolving credit commitment (the "PennTex Revolving Credit Facility"). In August 2017, the PennTex Revolving Credit Facility was repaid and terminated.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of September 30, 2017.

8. PREFERRED UNITS

In January 2017, Energy Transfer Partners, L.P. repurchased all of its 1.9 million outstanding Preferred Units for cash in the aggregate amount of $53 million.

9. EQUITY

The changes in outstanding common units during the nine months ended September 30, 2017 were as follows:

	Number of Units
Number of common units at December 31, 2016 [(1)]	794.8
Common Units issued in connection with public offerings	54.0
Common units issued in connection with equity distribution agreements	22.6
Common units issued in connection with the distribution reinvestment plan	4.6
Common units issued to ETE in a private placement transaction	23.7
Common unit increase from Sunoco Logistics Merger [(2)]	255.4
Issuance of common units under equity incentive plans	0.4
Number of common units at September 30, 2017	1,155.5

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

(2) Represents the Sunoco Logistics common units outstanding at the close of the Sunoco Logistics Merger. See Note 1 for discussion on the accounting treatment of the Sunoco Logistics Merger.

In connection with the Sunoco Logistics Merger, the previous Energy Transfer Partners, L.P. equity distribution agreement was terminated. In May 2017, the Partnership entered into an equity distribution agreement with an aggregate offering price up to $1.00 billion. During the nine months ended September 30, 2017, the Partnership received proceeds of $498 million, net of $5 million of commissions, from the issuance of common units pursuant to equity distribution agreements, which were used for general partnership purposes.

In connection with the Sunoco Logistics Merger, the previous Energy Transfer Partners, L.P. distribution reinvestment plan was terminated. In July 2017, the Partnership initiated a new distribution reinvestment plan. During the nine months ended September 30, 2017, distributions of $106 million were reinvested under the distribution reinvestment plan.

August 2017 Units Offering

In August 2017, the Partnership issued 54 million ETP common units in an underwritten public offering. Net proceeds of $997 million from the offering were used by the Partnership to repay amounts outstanding under its revolving credit facilities, to fund capital expenditures and for general partnership purposes.

Bakken Equity Sale

In February 2017, Bakken Holdings Company LLC, an entity in which the Partnership indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by Marathon Petroleum Corporation and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. In July 2017, the Partnership contributed a portion of its ownership interest in Dakota Access and ETCO to PEP, a strategic joint venture with ExxonMobil. ETP continues to consolidate Dakota Access and ETCO subsequent to this transaction.

PennTex Tender Offer and Limited Call Right Exercise

In June 2017, ETP purchased all of the outstanding PennTex common units not previously owned by ETP for $20.00 per common unit in cash. ETP now owns all of the economic interests of PennTex, and PennTex common units are no longer publicly traded or listed on the NASDAQ.

Quarterly Distributions of Available Cash

Following the Sunoco Logistics Merger, cash distributions are declared and paid in accordance with the Partnership’s limited partnership agreement, which was Sunoco Logistics’ limited partnership agreement prior to the Sunoco Logistics Merger. Under the agreement, within 45 days after the end of each quarter, the Partnership distributes all cash on hand at the end of the quarter, less reserves established by the general partner in its discretion. This is defined as “available cash” in the partnership agreement. The general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct the Partnership’s business. The Partnership will make quarterly distributions to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to the general partner.

If cash distributions exceed $0.0833 per unit in a quarter, the general partner receives increasing percentages, up to 50 percent, of the cash distributed in excess of that amount. These distributions are referred to as “incentive distributions.” The percentage interests shown for the unitholders and the general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

The following table shows the target distribution levels and distribution “splits” between the general partner and the holders of the Partnership’s common units:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		IDRs	Partners [(1)]
Minimum Quarterly Distribution	$0.0750	—%	100%
First Target Distribution	up to $0.0833	—%	100%
Second Target Distribution	above $0.0833 up to $0.0958	13%	87%
Third Target Distribution	above $0.0958 up to $0.2638	35%	65%
Thereafter	above $0.2638	48%	52%

[(1)] Includes general partner and limited partner interests, based on the proportionate ownership of each.

For the quarter ended December 31, 2016, Energy Transfer Partners, L.P. and Sunoco Logistics paid distributions on February 14, 2017 of $0.7033 and $0.52, respectively, per common unit.

Following are distributions declared and/or paid by the Partnership subsequent to the Sunoco Logistics Merger:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2017	May 10, 2017	May 15, 2017	$ 0.5350
June 30, 2017	August 7, 2017	August 14, 2017	0.5500
September 30, 2017	November 7, 2017	November 14, 2017	0.5650

ETE agreed to relinquish its right to the following amounts of incentive distributions in future periods.

	Total Year
2017 (remainder)	$ 173
2018	153
2019	128
Each year beyond 2019	33

Accumulated Other Comprehensive Income

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

	September 30, 2017	December 31, 2016
Available-for-sale securities	$ 7	$ 2
Foreign currency translation adjustment	(5)	(5)
Actuarial gain related to pensions and other postretirement benefits	9	7
Investments in unconsolidated affiliates, net	3	4
Total AOCI, net of tax	$ 14	$ 8

10. INCOME TAXES

For the nine months ended September 30, 2017, the Partnership’s income tax expense included the impact of a one-time adjustment to deferred tax balances as a result of a change in apportionment and corresponding state tax rates resulting from the Sunoco Logistics Merger in April 2017, which resulted in incremental income tax expense of approximately $68 million during the period. In addition, for the three months ended September 30, 2017, the Partnership recognized a $154 million deferred tax gain resulting from internal restructuring among its subsidiaries that resulted in a change in tax status for one of the subsidiaries. The three and nine months ended September 30, 2017 also reflect increased income tax expense due to higher earnings among the Partnership’s consolidated corporate subsidiaries. For the three and nine months ended September

30, 2016, the Partnership’s income tax benefit primarily resulted from losses among the Partnership’s consolidated corporate subsidiaries.

11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Contingent Residual Support Agreement – AmeriGas

In connection with the closing of the contribution of its propane operations in January 2012, ETLP (formerly Energy Transfer Partners, L.P.) agreed to provide contingent residual support of $1.55 billion of intercompany borrowings made by AmeriGas and certain of its affiliates with maturities through 2022 from a finance subsidiary of AmeriGas that have maturity dates and repayment terms that mirror those of an equal principal amount of senior notes issued by this finance company subsidiary to third-party purchasers. In 2016, AmeriGas repurchased certain of its senior notes, which caused a reduction in the amount supported by ETLP under the contingent residual support agreement. In February 2017, AmeriGas repurchased a portion of its 7.00% senior notes. The remaining outstanding 7.00% senior notes were repurchased in May 2017, and ETLP no longer provides contingent residual support for any AmeriGas notes.

Guarantee of Sunoco LP Notes

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

FERC Audit

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

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. The table below reflects rental expense under these operating leases included in operating expenses in the accompanying statements of operations, which include contingent rentals, and rental expense recovered through related sublease rental income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Rental expense	$ 29	$ 19	$ 68	$ 58

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates’ capital requirements, such as for funding capital projects or repayment of long-term obligations.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude oil are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

Dakota Access Pipeline

On July 25, 2016, the U.S. Army Corps of Engineers ("USACE") issued permits to Dakota Access consistent with environmental and historic preservation statutes for the pipeline to make two crossings of the Missouri River in North Dakota, including a crossing of the Missouri River at Lake Oahe. After significant delay, the USACE also issued easements to allow the pipeline to cross land owned by the USACE adjacent to the Missouri River in two locations. Also in July, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the U.S. District Court for the District of Columbia against the USACE that challenged the legality of the permits issued for the construction of the Dakota Access pipeline across those waterways and claimed violations of the National Historic Preservation Act ("NHPA"). The SRST also sought a preliminary injunction to rescind the USACE permits while the case is pending. Dakota Access intervened in the case. The SRST soon added a request for an emergency TRO to stop construction on the pipeline project. On September 9, 2016, the Court denied SRST's motion for a preliminary injunction, rendering the temporary restraining order ("TRO") request moot.

After the September 9, 2016 ruling, the Department of the Army, the DOJ, and the Department of the Interior released a joint statement that the USACE would not grant the easement for the land adjacent to Lake Oahe until the Army completed a review to determine whether it was necessary to reconsider the USACE's decision under various federal statutes relevant to the pipeline approval.

The SRST appealed the denial of the preliminary injunction to the U.S. Court of Appeals for the D.C. Circuit and filed an emergency motion in the U.S. District Court for an injunction pending the appeal, which was denied. The D.C. Circuit then denied the SRST's application for an injunction pending appeal and later dismissed SRST's appeal of the order denying the preliminary injunction motion. The SRST filed an amended complaint and added claims based on treaties between the tribes and the United States and statutes governing the use of government property.

In December 2016, the Department of the Army announced that, although its prior actions complied with the law, it intended to conduct further environmental review of the crossing at Lake Oahe. In February 2017, in response to a presidential memorandum, the Department of the Army decided that no further environmental review was necessary and delivered an easement to Dakota Access allowing the pipeline to cross Lake Oahe. Almost immediately, the Cheyenne River Sioux Tribe ("CRST"), which had intervened in the lawsuit in August 2016, moved for a preliminary injunction and TRO to block operation of the pipeline. These motions raised, for the first time, claims based on the religious rights of the Tribe. The district court denied the TRO and preliminary injunction, and the CRST appealed and requested an injunction pending appeal in the district court and the D.C. Circuit. Both courts denied the CRST's request for an injunction pending appeal. Shortly thereafter, at CRST's request, the D.C. Circuit dismissed CRST's appeal.

The SRST and the CRST amended their complaints to incorporate religious freedom and other claims. In addition, the Oglala and Yankton Sioux tribes have filed related lawsuits to prevent construction of the Dakota Access pipeline project. These lawsuits have been consolidated into the action initiated by the SRST. Several individual members of the Tribes have also intervened in the lawsuit asserting claims that overlap with those brought by the four tribes.

On June 14, 2017, the Court ruled on SRST's and CRST's motions for partial summary judgment and the USACE's cross-motions for partial summary judgment. The Court rejected the majority of the Tribes' assertions and granted summary judgment on most claims in favor of the USACE and Dakota Access. In particular, the Court concluded that the USACE had not violated any trust duties owed to the Tribes and had generally complied with its obligations under the Clean Water Act, the Rivers and Harbors Act, the Mineral Leasing Act, the National Environmental Policy Act ("NEPA") and other related statutes; however, the Court remanded to the USACE three discrete issues for further analysis and explanation of its prior determination under certain of these statutes. The Court ordered briefing to determine whether the pipeline should remain in operation during the pendency of the USACE's review process or whether to vacate the existing permits. The USACE and Dakota Access opposed any shutdown of operations of the pipeline during this review process. On October 11, 2017, the Court issued an order allowing the pipeline to remain in operation during the pendency of the USACE's review process. In early October 2017, USACE advised the Court that it expects to complete this additional work by April 2018. The Court has stayed consideration of any other claims until it fully resolves the remaining issues relating to its remand order.

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

Mont Belvieu Incident

On June 26, 2016, a hydrocarbon storage well located on another operator's facility adjacent to Lone Star NGL Mont Belvieu's ("Lone Star") facilities in Mont Belvieu, Texas experienced an over-pressurization resulting in a subsurface release. The subsurface release caused a fire at Lone Star's South Terminal (CMB) and damage to Lone Star's storage well operations at its South and North Terminals. Normal operations have resumed at the facilities with the exception of one of Lone Star's storage wells. Lone Star is still quantifying the extent of its incurred and ongoing damages and has or will be seeking reimbursement for these losses.

MTBE Litigation

Sunoco, Inc. and/or Sunoco, Inc. (R&M), along with other refiners, manufacturers and sellers of gasoline, are defendants in lawsuits alleging MTBE contamination of groundwater. The plaintiffs, typically governmental authorities, assert product liability claims and additional claims including nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices. The plaintiffs seek to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages, and attorneys' fees.

As of September 30, 2017, Sunoco, Inc. is a defendant in six cases, including cases initiated by the States of New Jersey, Vermont, Pennsylvania, Rhode Island, and two others by the Commonwealth of Puerto Rico with the more recent Puerto Rico action being a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. Four of these cases are venued in a multidistrict litigation proceeding in a New York federal court.

Sunoco, Inc. and Sunoco, Inc. (R&M) have reached a settlement with the State of New Jersey. The court approved the Judicial Consent Order on October 10, 2017.

It is reasonably possible that a loss may be realized in the remaining cases; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. An adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any such adverse determination occurs, but such an adverse determination likely would not have a material adverse effect on the Partnership's consolidated financial position.

Regency Merger Litigation

Following the January 26, 2015 announcement of the Regency-ETP merger (the "Regency Merger"), purported Regency unitholders filed lawsuits in state and federal courts in Dallas and Delaware asserting claims relating to the Regency Merger. All but one Regency Merger-related lawsuits have been dismissed. On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint, Dieckman v. Regency GP LP, et al., C.A. No. 11130-CB, in the Court of Chancery of the State of Delaware (the "Regency Merger Litigation"), on behalf of Regency's common unitholders against Regency GP, LP; Regency GP LLC; ETE, ETP, ETP GP, and the members of Regency's board of directors (the "Regency Litigation Defendants").

The Regency Merger litigation alleges that the Regency Merger breached the Regency partnership agreement because Regency's conflicts committee was not properly formed, and the Regency Merger was not approved in good faith. On March 29, 2016, the Delaware Court of Chancery granted defendants' motion to dismiss the lawsuit in its entirety. Dieckman appealed. On January 20, 2017, the Delaware Supreme Court reversed the judgment of the Court of Chancery. On May 5, 2017, Plaintiff filed an Amended Verified Class Action Complaint. The Regency Merger Litigation Defendants then filed Motions to Dismiss the Amended Complaint and a Motion to Stay Discovery on May 19, 2017. A hearing on these motions is currently set for January 9, 2018.

The Regency Merger Litigation Defendants cannot predict the outcome of the Regency Merger Litigation or any lawsuits that might be filed subsequent to the date of this filing; nor can the Regency Merger Litigation Defendants predict the amount of time and expense that will be required to resolve the Regency Merger Litigation. The Regency Litigation Defendants believe the Regency Merger Litigation is without merit and intend to vigorously defend against it and any others that may be filed in connection with the Regency Merger.

Enterprise Products Partners, L.P. and Enterprise Products Operating LLC Litigation

On January 27, 2014, a trial commenced between ETP against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETP against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETP. The jury also found that ETP owed Enterprise approximately $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETP and awarded ETP $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETP shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise filed a notice of appeal with the Court of Appeals. On July 18, 2017, the Court of Appeals issued its opinion and reversed the trial court's judgment. ETP's motion for rehearing to the Court of Appeals was denied. ETP intends to file a petition for review with the Texas Supreme Court.

Sunoco Logistics Merger Litigation

Seven purported Energy Transfer Partners, L.P. common unitholders (the "ETP Unitholder Plaintiffs") separately filed seven putative unitholder class action lawsuits against ETP, ETP GP, ETP LLC, the members of the ETP Board, and ETE (the "ETP-SXL Defendants") in connection with the announcement of the Sunoco Logistics Merger. Two of these lawsuits have been voluntarily dismissed. The five remaining lawsuits have been consolidated as In re Energy Transfer Partners, L.P. Shareholder Litig., C.A. No. 1:17-cv-00044-CCC, in the United States District Court for the District of Delaware (the "Sunoco Logistics Merger Litigation"). The ETP Unitholder Plaintiffs allege causes of action challenging the merger and the proxy statement/prospectus filed in connection with the Sunoco Logistics Merger (the "ETP-SXL Merger Proxy"). The ETP Unitholder Plaintiffs seek rescission of the Sunoco Logistics Merger or rescissory damages for ETP unitholders, as well as an award of costs and attorneys' fees.

The ETP-SXL Defendants cannot predict the outcome of the Sunoco Logistics Merger Litigation or any lawsuits that might be filed subsequent to the date of this filing, nor can the ETP-SXL Defendants predict the amount of time and expense that will be required to resolve the Sunoco Logistics Merger Litigation. The ETP-SXL Defendants believe the Sunoco Logistics Merger Litigation is without merit and intend to defend vigorously against it and any other actions challenging the Sunoco Logistics Merger.

Litigation filed by BP Products

On April 30, 2015, BP Products North America Inc. ("BP") filed a complaint with the FERC, *BP Products North America Inc. v. Sunoco Pipeline L.P.*, FERC Docket No. OR15-25-000, alleging that Sunoco Pipeline L.P. ("SPLP"), a wholly-owned subsidiary of ETP, entered into certain throughput and deficiency ("T&D") agreements with shippers other than BP regarding SPLP's crude oil pipeline between Marysville, Michigan and Toledo, Ohio, and revised its proration policy relating to that pipeline in an unduly discriminatory manner in violation of the Interstate Commerce Act ("ICA"). The complaint asked FERC to (1) terminate the agreements with the other shippers, (2) revise the proration policy, (3) order SPLP to restore BP's volume history to the level that existed prior to the execution of the agreements with the other shippers, and (4) order damages to BP of approximately $62 million, a figure that BP reduced in subsequent filings to approximately $41 million.

SPLP denied the allegations in the complaint and asserted that neither its contracts nor proration policy were unlawful and that BP's complaint was barred by the ICA's two-year statute of limitations provision. Interventions were filed by the two companies with which SPLP entered into T&D agreements, Marathon Petroleum Company ("Marathon") and PBF Holding Company and Toledo Refining Company (collectively, "PBF"). A hearing on the matter was held in November 2016.

On May 26, 2017, the Administrative Law Judge Patricia E. Hurt ("ALJ") issued her initial decision ("Initial Decision") and found that SPLP had acted discriminatorily by entering into T&D agreements with the two shippers other than BP and recommended that the FERC (1) adopt the FERC Trial Staff's $13 million alternative damages proposal, (2) void the T&D agreements with Marathon and PBF, (3) re-set each shipper's volume history to the level prior to the effective date of the proration policy, and (4) investigate the proration policy. The ALJ held that BP's claim for damages was not time-barred in its entirety, but that it was not entitled to damages more than two years prior to the filing of the complaint.

On July 26, 2017, each of the parties filed with the FERC a brief on exceptions to the Initial Decision. SPLP challenged all of the Initial Decision's primary findings (except for the adjustment to the individual shipper volume histories). BP and FERC Trial Staff challenged various aspects of the Initial Decision related to remedies and the statute of limitations issue. On September 18 and 19, 2017, all parties filed briefs opposing the exceptions of the other parties. The matter is now awaiting a decision by FERC.

Other Litigation and Contingencies

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of September 30, 2017 and December 31, 2016, accruals of approximately $66 million and $77 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued.

In December 2016, Sunoco Logistics received multiple Notice of Violations ("NOVs") from the Delaware County Regional Water Quality Control Authority ("DELCORA") in connection with a discharge at its Marcus Hook Industrial Complex ("MHIC") in July 2016. Sunoco Logistics also entered in a Consent Order and Agreement from the Pennsylvania Department of Environmental Protection ("PADEP") related to its tank inspection plan at MHIC. These actions propose penalties in excess of $0.1 million, and ETP is currently in discussions with the PADEP and DELCORA to resolve these matters. The timing or outcome of these matters cannot be reasonably determined at this time, however, the Partnership does not expect there to be a material impact to its results of operations, cash flows, or financial position.

The Ohio Environmental Protection Agency ("Ohio EPA") has alleged that various environmental violations have occurred during construction of the Rover pipeline project. The alleged violations include inadvertent returns of drilling muds and fluids at horizontal directional drilling ("HDD") locations in Ohio that affected waters of the State, storm water control violations, improper disposal of spent drilling mud containing diesel fuel residuals, and open burning. The alleged violations occurred from April to July, 2017. The Ohio EPA has proposed penalties of approximately $2.3 million in connection with the alleged violations and is seeking certain corrective actions. ETP is working with Ohio EPA to resolve the matter. The timing or outcome of this matter cannot be reasonably determined at this time; however, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

In addition, on May 10, 2017, the FERC prohibited Rover from conducting HDD activities at 27 sites in Ohio. On July 31, 2017, the FERC issued an independent third party assessment of what led to the release at the Tuscarawas River site and what Rover can do to prevent reoccurrence once the HDD suspension is lifted. Rover has notified the FERC of its intention to implement the suggestions in the assessment and to implement additional voluntary protocols. On September 18, 2017, the FERC authorized Rover to resume HDD activities at the Tuscarawas River site and nine other river crossing sites. On October 20, 2017, the FERC authorized Rover to resume HDD activities at two additional sites.

On July 17, 2017, the West Virginia Department of Environmental Protection ("WVDEP") issued a Cease and Desist order requiring Rover, among other things, to cease any land development activity in Doddridge and Tyler Counties. Under the order, Rover had 20 days to submit a corrective action plan and schedule for agency review. The order followed several notices of violation WVDEP issued to Rover alleging stormwater non-compliance. Rover is complying with the order and has already addressed many of the stormwater control issues. On August 9, 2017, WVDEP lifted the Cease and Desist requirement.

On July 25, 2017, the Pennsylvania Environmental Hearing Board ("EHB") issued an order to SPLP to cease HDD activities in Pennsylvania related to the Mariner East 2 project. On August 1, 2017 the EHB lifted the order as to two drill locations. On August 3, 2017, the EHB lifted the order as to 14 additional locations. The EHB issued the order in response to a complaint filed by environmental groups against SPLP and the Pennsylvania Department of Environmental Protection ("PADEP"). The EHB Judge encouraged the parties to pursue a settlement with respect to the remaining HDD locations and facilitated a settlement meeting. On August 7, 2017 a final settlement was reached. A stipulated order has been submitted to the EHB Judge with respect to the settlement. The settlement agreement requires that SPLP reevaluate the design parameters of approximately 26 drills on the Mariner East 2 project and approximately 43 drills on the Mariner East 2X project. The settlement agreement also provides a defined framework for approval by PADEP for these drills to proceed after reevaluation. Additionally, the settlement agreement requires modifications to several of the HDD plans that are part of the PADEP permits. Those modifications have been completed and agreed to by the parties and the reevaluation of the drills has been initiated by the company.

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

No amounts have been recorded in our September 30, 2017 or December 31, 2016 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Environmental Matters

Our operations are subject to extensive federal, tribal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations but there can be no assurance that such costs will not be material in the future or that such future compliance with existing, amended or new legal requirements will not have a material adverse effect on our business and operating results. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the issuance of injunctions in affected areas and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

In February 2017, we received letters from the DOJ and Louisiana Department of Environmental Quality notifying Sunoco Pipeline L.P. (“SPLP”) and Mid-Valley Pipeline Company (“Mid-Valley”) that enforcement actions were being pursued for three crude oil releases: (a) an estimated 550 barrels released from the Colmesneil-to-Chester pipeline in Tyler County, Texas (“Colmesneil”) operated and owned by SPLP in February of 2013; (b) an estimated 4,509 barrels released from the Longview-to-Mayersville pipeline in Caddo Parish, Louisiana (a/k/a Milepost 51.5) operated by SPLP and owned by Mid-Valley in October of 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma operated and owned by SPLP in January of 2015. In May of this year, we presented to the DOJ, EPA and Louisiana Department of Environmental Quality a summary of the emergency response and remedial efforts taken by SPLP after the releases occurred as well as operational changes instituted by SPLP to reduce the likelihood of future releases. In July, we had a follow-up meeting with the DOJ, EPA and Louisiana Department of Environmental Quality during which the agencies presented their initial demand for civil penalties and injunctive relief. In short, the DOJ and EPA proposed federal penalties totaling $7 million for the three releases along with a demand for injunctive relief, and Louisiana Department of Environmental Quality proposed a state penalty of approximately $1 million to resolve the Caddo Parish release. Neither Texas nor Oklahoma state agencies have joined the penalty discussions at this point. We are currently working on a counteroffer to the Louisiana Department of Environmental Quality.

Environmental Remediation

Our subsidiaries are responsible for environmental remediation at certain sites, including the following:

- Certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- Certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- Currently operating Sunoco, Inc. retail sites previously contributed to Sunoco LP in January 2016.
- Legacy sites related to Sunoco, Inc. that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco, Inc. is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of September 30, 2017, Sunoco, Inc. had been named as a PRP at approximately 44 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.’s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

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

The table below reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	September 30, 2017	December 31, 2016
Current	$ 36	$ 26
Non-current	276	283
Total environmental liabilities	$ 312	$ 309

In 2013, we established a wholly-owned captive insurance company to bear certain risks associated with environmental obligations related to certain sites that are no longer operating. The premiums paid to the captive insurance company include estimates for environmental claims that have been incurred but not reported, based on an actuarially determined fully developed claims expense estimate. In such cases, we accrue losses attributable to unasserted claims based on the discounted estimates that are used to develop the premiums paid to the captive insurance company.

During the three months ended September 30, 2017 and 2016, Sunoco, Inc. recorded $4 million and $10 million, respectively, of expenditures related to environmental cleanup programs. During the nine months ended September 30, 2017 and 2016, Sunoco, Inc. recorded $14 million and $24 million, respectively, of expenditures related to environmental cleanup programs.

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

Our operations are also subject to the requirements of OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our past costs for OSHA required activities, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances have not had a material adverse effect on our results of operations but there is no assurance that such costs will not be material in the future.

12. DERIVATIVE ASSETS AND LIABILITIES

Commodity Price Risk

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

We use futures and basis swaps, designated as fair value hedges, to hedge our natural gas inventory stored in our Bammel storage facility. At hedge inception, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract. Changes in the spreads between the forward natural gas prices and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized.

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

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

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

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

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

The following table details our outstanding commodity-related derivatives:

	September 30, 2017		December 31, 2016	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (MMBtu):				
Fixed Swaps/Futures	1,297,500	2017-2018	(682,500)	2017
Basis Swaps IFERC/NYMEX[1]	(15,810,000)	2017-2019	2,242,500	2017
Options – Puts	13,000,000	2018	—	—
Power (Megawatt):				
Forwards	665,040	2017-2018	391,880	2017-2018
Futures	(213,840)	2017-2018	109,564	2017-2018
Options – Puts	(280,800)	2017-2018	(50,400)	2017
Options – Calls	545,600	2017-2018	186,400	2017
Crude (Bbls) – Futures	(160,000)	2017	(617,000)	2017
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	67,500	2017-2020	10,750,000	2017-2018
Swing Swaps IFERC	91,897,500	2017-2019	(5,662,500)	2017
Fixed Swaps/Futures	(20,220,000)	2017-2019	(52,652,500)	2017-2019
Forward Physical Contracts	(140,937,993)	2017-2018	(22,492,489)	2017
Natural Gas Liquid (Bbls) – Forwards/Swaps	(8,747,200)	2017-2019	(5,786,627)	2017
Refined Products (Bbls) – Futures	(701,000)	2017	(2,240,000)	2017
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (MMBtu):				
Basis Swaps IFERC/NYMEX	(41,102,500)	2017	(36,370,000)	2017
Fixed Swaps/Futures	(41,102,500)	2017	(36,370,000)	2017
Hedged Item – Inventory	41,102,500	2017	36,370,000	2017

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

Interest Rate Risk

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

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

		Notional Amount Outstanding	
Term	Type[1]	September 30, 2017	December 31, 2016
July 2017[2]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	$ —	$ 500
July 2018[2]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	300	200
July 2019[2]	Forward-starting to pay a fixed rate of 3.64% and receive a floating rate	300	200
July 2020[2]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	—
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300

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

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

Credit Risk

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

The Partnership’s counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, municipalities, gas and electric utilities, midstream companies and independent power generators. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that impact our counterparties to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of counterparty non-performance.

The Partnership has maintenance margin deposits with certain counterparties in the OTC market, primarily independent system operators, and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on or about the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets.

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

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	September 30, 2017	December 31, 2016	September 30, 2017	December 31, 2016
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 7	$ —	$ —	$ (4)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	222	338	(262)	(416)
Commodity derivatives	50	24	(60)	(52)
Interest rate derivatives	—	—	(210)	(193)
Embedded derivatives in Preferred Units	—	—	—	(1)
	272	362	(532)	(662)
Total derivatives	$ 279	$ 362	$ (532)	$ (666)

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

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	September 30, 2017	December 31, 2016	September 30, 2017	December 31, 2016
Derivatives without offsetting agreements	Derivative assets (liabilities)	$ —	$ —	$ (210)	$ (194)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	50	24	(60)	(52)
Broker cleared derivative contracts	Other current assets	229	338	(262)	(420)
Total gross derivatives		279	362	(532)	(666)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(10)	(4)	10	4
Payments on margin deposit	Other current assets	(220)	(338)	220	338
Total net derivatives		$ 49	$ 20	$ (302)	$ (324)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments:

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2017	2016	2017	2016
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ 2	$ (9)	$ 4	$ 8
Total		$ 2	$ (9)	$ 4	$ 8

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2017	2016	2017	2016
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$ (5)	$ (8)	$ 21	$ (24)
Commodity derivatives – Non-trading	Cost of products sold	(12)	(14)	(15)	(57)
Interest rate derivatives	Losses on interest rate derivatives	(8)	(28)	(28)	(179)
Embedded derivatives	Other, net	—	8	1	4
Total		$ (25)	$ (42)	$ (21)	$ (256)

13. RELATED PARTY TRANSACTIONS

In June 2017, the Partnership acquired all of the publicly held PennTex common units through a tender offer and exercise of a limited call right, as further discussed in Note 9.

We previously had agreements with ETE to provide services on its behalf and on behalf of other subsidiaries of ETE, which included the reimbursement of various operating and general and administrative expenses incurred by us on behalf of ETE and its subsidiaries. These agreements expired in 2016.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Affiliated revenues	$ 190	$ 63	$ 441	$ 270

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

	September 30, 2017	December 31, 2016
Accounts receivable from related companies:		
ETE	$ —	$ 22
Sunoco LP	204	96
FGT	15	15
Other	116	76
Total accounts receivable from related companies:	$ 335	$ 209
Accounts payable to related companies:		
Sunoco LP	$ 178	$ 20
Other	26	23
Total accounts payable to related companies:	$ 204	$ 43

	September 30, 2017	December 31, 2016
Long-term notes receivable (payable) – related companies:		
Sunoco LP	$ 85	$ 87
Phillips 66	—	(250)
Net long-term notes receivable (payable) – related companies	$ 85	$ (163)

14. REPORTABLE SEGMENTS

Subsequent to the Sunoco Logistics Merger, our financial statements reflect the following reportable segments, which conduct their business in the United States, as follows:

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

The amounts included in the NGL and refined products transportation and services segment and the crude oil transportation and services segment have been retrospectively adjusted in these consolidated financial statements as a result of the Sunoco Logistics Merger.

The Partnership previously presented its retail marketing business as a separate reportable segment. Due to the transfer of the general partner interest of Sunoco LP from Energy Transfer Partners, L.P. to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from Energy Transfer Partners, L.P. to Sunoco LP in March 2016, all of the Partnership's retail marketing business has been deconsolidated. The only remaining retail marketing assets are the limited partner units of Sunoco LP owned by the Partnership. As of September 30, 2017, the Partnership owned 43.5 million Sunoco LP common units, representing 43.7% of Sunoco LP's total outstanding common units. This equity method investment in Sunoco LP has now been aggregated into the all other segment. Consequently, the retail marketing business that was previously consolidated has also been aggregated in the all other segment for all periods presented.

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

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

The following tables present financial information by segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 729	$ 583	$ 2,196	$ 1,457
Intersegment revenues	44	175	146	400
	773	758	2,342	1,857
Interstate transportation and storage:				
Revenues from external customers	220	231	652	714
Intersegment revenues	4	5	14	15
	224	236	666	729
Midstream:				
Revenues from external customers	665	582	1,863	1,799
Intersegment revenues	1,100	761	3,154	1,966
	1,765	1,343	5,017	3,765
NGL and refined products transportation and services:				
Revenues from external customers	1,989	1,397	5,874	4,014
Intersegment revenues	81	148	241	315
	2,070	1,545	6,115	4,329
Crude oil transportation and services:				
Revenues from external customers	2,714	1,856	7,749	5,146
Intersegment revenues	11	—	16	—
	2,725	1,856	7,765	5,146
All other:				
Revenues from external customers	656	882	2,110	2,171
Intersegment revenues	27	74	139	350
	683	956	2,249	2,521
Eliminations	(1,267)	(1,163)	(3,710)	(3,046)
Total revenues	$ 6,973	$ 5,531	$ 20,444	$ 15,301

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$ 163	$ 133	$ 480	$ 461
Interstate transportation and storage	273	278	800	848
Midstream	356	314	1,088	875
NGL and refined products transportation and services	423	383	1,196	1,072
Crude oil transportation and services	396	169	830	521
All other	133	113	363	395
Total	1,744	1,390	4,757	4,172
Depreciation, depletion and amortization	(596)	(503)	(1,713)	(1,469)
Interest expense, net	(367)	(345)	(1,052)	(981)
Losses on interest rate derivatives	(8)	(28)	(28)	(179)
Non-cash unit-based compensation expense	(19)	(22)	(57)	(60)
Unrealized gains (losses) on commodity risk management activities	(81)	(15)	17	(96)
Inventory valuation adjustments	86	37	30	143
Adjusted EBITDA related to unconsolidated affiliates	(279)	(240)	(765)	(711)
Equity in earnings of unconsolidated affiliates	127	65	139	260
Impairment of investment in an unconsolidated affiliate	—	(308)	—	(308)
Other, net	42	43	111	84
Income before income tax expense (benefit)	$ 649	$ 74	$ 1,439	$ 855

	September 30, 2017	December 31, 2016
Assets:		
Intrastate transportation and storage	$ 5,179	$ 5,164
Interstate transportation and storage	12,194	10,833
Midstream	19,781	17,873
NGL and refined products transportation and services	16,445	14,128
Crude oil transportation and services	17,267	15,941
All other	6,145	6,252
Total assets	$ 77,011	$ 70,191

15. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

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

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

The following supplemental condensed consolidating financial information reflects the Parent Guarantor’s separate accounts, the Subsidiary Issuer’s separate accounts, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and the Parent Guarantor’s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent Guarantor’s investments in its subsidiaries and the Subsidiary Issuer’s investments in its subsidiaries are accounted for under the equity method of accounting.

To present the supplemental condensed consolidating financial information on a comparable basis, the prior period financial information has been recast as if the Sunoco Logistics Merger occurred on January 1, 2016.

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

	September 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ 49	$ 330	$ —	$ 379
All other current assets	—	77	5,324	—	5,401
Property, plant and equipment, net	—	—	56,972	—	56,972
Investments in unconsolidated affiliates	25,174	11,605	4,221	(36,779)	4,221
All other assets	—	25	10,013	—	10,038
Total assets	$ 25,174	$ 11,756	$ 76,860	$ (36,779)	$ 77,011
Current liabilities	$ (1,494)	$ (3,819)	$ 12,199	$ —	$ 6,886
Non-current liabilities	—	7,664	31,604	—	39,268
Noncontrolling interest	—	—	4,191	—	4,191
Total partners' capital	26,668	7,911	28,866	(36,779)	26,666
Total liabilities and equity	$ 25,174	$ 11,756	$ 76,860	$ (36,779)	$ 77,011

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

	Three Months Ended September 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 6,973	$ —	$ 6,973
Operating costs, expenses, and other	—	—	6,148	—	6,148
Operating income	—	—	825	—	825
Interest expense, net	—	(32)	(335)	—	(367)
Equity in earnings of unconsolidated affiliates	647	236	127	(883)	127
Losses on interest rate derivatives	—	—	(8)	—	(8)
Other, net	—	1	71	—	72
Income before income tax benefit	647	205	680	(883)	649
Income tax benefit	—	—	(112)	—	(112)
Net income	647	205	792	(883)	761
Less: Net income attributable to noncontrolling interest	—	—	110	—	110
Net income attributable to partners	$ 647	$ 205	$ 682	$ (883)	$ 651
Other comprehensive income	$ —	$ —	$ 7	$ —	$ 7
Comprehensive income	647	205	799	(883)	768
Comprehensive income attributable to noncontrolling interest	—	—	110	—	110
Comprehensive income attributable to partners	$ 647	$ 205	$ 689	$ (883)	$ 658

	Three Months Ended September 30, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 5,531	$ —	$ 5,531
Operating costs, expenses, and other	—	—	4,893	—	4,893
Operating income	—	—	638	—	638
Interest expense, net	—	(39)	(306)	—	(345)
Equity in earnings of unconsolidated affiliates	119	193	65	(312)	65
Impairment of investment in an unconsolidated affiliate	—	—	(308)	—	(308)
Losses on interest rate derivatives	—	—	(28)	—	(28)
Other, net	—	—	52	—	52
Income before income tax benefit	119	154	113	(312)	74
Income tax benefit	—	—	(64)	—	(64)
Net income	119	154	177	(312)	138
Less: Net income attributable to noncontrolling interest	—	—	21	—	21
Net income attributable to partners	$ 119	$ 154	$ 156	$ (312)	$ 117
Other comprehensive income	$ —	$ —	$ 2	$ —	$ 2
Comprehensive income	119	154	179	(312)	140
Comprehensive income attributable to noncontrolling interest	—	—	21	—	21
Comprehensive income attributable to partners	$ 119	$ 154	$ 158	$ (312)	$ 119

	Nine Months Ended September 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 20,444	$ —	$ 20,444
Operating costs, expenses, and other	—	1	18,232	—	18,233
Operating income (loss)	—	(1)	2,212	—	2,211
Interest expense, net	—	(113)	(939)	—	(1,052)
Equity in earnings of unconsolidated affiliates	1,657	1,001	139	(2,658)	139
Losses on interest rate derivatives	—	—	(28)	—	(28)
Other, net	—	4	166	(1)	169
Income before income tax expense	1,657	891	1,550	(2,659)	1,439
Income tax expense	—	—	22	—	22
Net income	1,657	891	1,528	(2,659)	1,417
Less: Net income attributable to noncontrolling interest	—	—	216	—	216
Net income attributable to partners	$ 1,657	$ 891	$ 1,312	$ (2,659)	$ 1,201
Other comprehensive income	$ —	$ —	$ 6	$ —	$ 6
Comprehensive income	1,657	891	1,534	(2,659)	1,423
Comprehensive income attributable to noncontrolling interest	—	—	216	—	216
Comprehensive income attributable to partners	$ 1,657	$ 891	$ 1,318	$ (2,659)	$ 1,207

	Nine Months Ended September 30, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 15,301	$ —	$ 15,301
Operating costs, expenses, and other	—	1	13,333	—	13,334
Operating income (loss)	—	(1)	1,968	—	1,967
Interest expense, net	—	(116)	(865)	—	(981)
Equity in earnings of unconsolidated affiliates	930	618	260	(1,548)	260
Impairment of investment in an unconsolidated affiliate	—	—	(308)	—	(308)
Losses on interest rate derivatives	—	—	(179)	—	(179)
Other, net	—	—	96	—	96
Income before income tax benefit	930	501	972	(1,548)	855
Income tax benefit	—	—	(131)	—	(131)
Net income	930	501	1,103	(1,548)	986
Less: Net income attributable to noncontrolling interest	—	—	57	—	57
Net income attributable to partners	$ 930	$ 501	$ 1,046	$ (1,548)	$ 929
Other comprehensive loss	$ —	$ —	$ (8)	$ —	$ (8)
Comprehensive income	930	501	1,095	(1,548)	978
Comprehensive income attributable to noncontrolling interest	—	—	57	—	57
Comprehensive income attributable to partners	$ 930	$ 501	$ 1,038	$ (1,548)	$ 921

	Nine Months Ended September 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 1,657	$ 802	$ 3,538	$ (2,660)	$ 3,337
Cash flows used in investing activities	(1,348)	(1,127)	(4,872)	2,660	(4,687)
Cash flows provided by (used in) financing activities	(309)	333	1,345	—	1,369
Change in cash	—	8	11	—	19
Cash at beginning of period	—	41	319	—	360
Cash at end of period	$ —	$ 49	$ 330	$ —	$ 379

	Nine Months Ended September 30, 2016				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 929	$ 491	$ 2,593	$ (1,548)	$ 2,465
Cash flows used in investing activities	(1,537)	(918)	(2,733)	1,548	(3,640)
Cash flows provided by (used in) financing activities	606	429	(10)	—	1,025
Change in cash	(2)	2	(150)	—	(150)
Cash at beginning of period	—	37	490	—	527
Cash at end of period	$ (2)	$ 39	$ 340	$ —	$ 377

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; and (ii) the consolidated financial statements and management's discussion and analysis of financial condition and results of operations included in Exhibit 99.1 to the Partnership's Current Report on Form 8-K filed with the SEC on August 14, 2017. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Part I – Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2016 filed with the SEC on February 24, 2017 and Exhibit 99.3 to the Partnership's Current Report on Form 8-K filed with the SEC on May 8, 2017.

References to "we," "us," "our," the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries. See Note 1 to the consolidated financial statements for information related to the entity's recent name change.

OVERVIEW

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

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

RECENT DEVELOPMENTS

ETP Senior Notes Redemption

In October 2017, the Partnership redeemed all of the outstanding $500 million aggregate principal amount of ETLP's 6.50% senior notes due July 2021 and all of the outstanding $700 million aggregate principal amount of ETLP's 5.50% senior notes due April 2023. The aggregate amount paid to redeem these notes, including call premiums, was approximately $1.23 billion.

ETP Senior Notes Offering

In September 2017, Sunoco Logistics Partners Operations L.P., a subsidiary of ETP, issued $750 million aggregate principal amount of 4.00% senior notes due 2027 and $1.50 billion aggregate principal amount of 5.40% senior notes due 2047. The $2.22 billion net proceeds from the offering were used to redeem all of the $500 million aggregate principal amount of ETLP's 6.5% senior notes due 2021, to repay borrowings outstanding under the Sunoco Logistics Credit Facility and for general partnership purposes.

August 2017 Units Offering

In August 2017, the Partnership issued 54 million ETP common units in an underwritten public offering. Net proceeds of $997 million from the offering were used by the Partnership to repay amounts outstanding under its revolving credit facilities, to fund capital expenditures and for general partnership purposes.

Rover Contribution Agreement

In July 2017, ETP announced that it had entered into a contribution agreement with a fund managed by Blackstone Energy Partners and Blackstone Capital Partners ("Blackstone"), for the purchase by Blackstone of a 49.9% interest in the holding company that owns 65% of the Rover pipeline ("Rover Holdco"). The agreement with Blackstone required Blackstone to contribute, at closing, funds to reimburse ETP for its pro rata share of the Rover construction costs incurred by ETP through the closing date, along with the payment of additional amounts subject to certain adjustments. The transaction closed in October 2017. As a result of this closing, Rover Holdco is now owned 50.1% by ETP and 49.9% by Blackstone.

PennTex Tender Offer and Limited Call Right Exercise

In June 2017, ETP purchased all of the outstanding PennTex common units not previously owned by ETP for $20.00 per common unit in cash. ETP now owns all of the economic interests of PennTex, and PennTex common units are no longer publicly traded or listed on the NASDAQ.

Sunoco Logistics Merger

In April 2017, Energy Transfer Partners, L.P. and Sunoco Logistics completed the merger transaction (the “Sunoco Logistics Merger”) in which Sunoco Logistics acquired Energy Transfer Partners, L.P. in a unit-for-unit transaction. Under the terms of the transaction, the unitholders received 1.5 common units of Sunoco Logistics for each Energy Transfer Partners, L.P. common unit they owned. Under the terms of the merger agreement, Sunoco Logistics’ general partner was merged with and into ETP GP, with ETP GP surviving as an indirect wholly-owned subsidiary of ETE.

Permian Express Partners

In February 2017, Sunoco Logistics formed Permian Express Partners LLC (“PEP”), a strategic joint venture with ExxonMobil. Sunoco Logistics contributed its Permian Express 1, Permian Express 2, Permian Longview and Louisiana Access pipelines. ExxonMobil contributed its Longview to Louisiana and Pegasus pipelines, Hawkins gathering system, an idle pipeline in southern Oklahoma, and its Patoka, Illinois terminal. Assets contributed to PEP by ExxonMobil were reflected at fair value on the Partnership’s consolidated balance sheet at the date of the contribution, including $547 million of intangible assets and $435 million of property, plant and equipment.

In July 2017, the Partnership contributed an approximate 15% ownership interest in Dakota Access, LLC (“Dakota Access”) and Energy Transfer Crude Oil Company, LLC (“ETCO”) to PEP, which resulted in an increase in the Partnership’s ownership interest in PEP to approximately 88%. The Partnership maintains a controlling financial and voting interest in PEP and is the operator of all of the assets. As such, PEP is reflected as a consolidated subsidiary of the Partnership. ExxonMobil’s interest in PEP is reflected as noncontrolling interest in the consolidated balance sheets. ExxonMobil’s contribution resulted in an increase of $988 million in noncontrolling interest, which is reflected in “Capital contributions from noncontrolling interest” in the consolidated statement of equity.

Bakken Equity Sale

In February 2017, Bakken Holdings Company LLC, an entity in which the Partnership indirectly owns a 100% membership interest, sold a 49% interest in its wholly-owned subsidiary, Bakken Pipeline Investments LLC, to MarEn Bakken Company LLC, an entity jointly owned by Marathon Petroleum Corporation and Enbridge Energy Partners, L.P., for $2.00 billion in cash. Bakken Pipeline Investments LLC indirectly owns a 75% interest in each of Dakota Access and ETCO. The remaining 25% of each of Dakota Access and ETCO is owned by wholly-owned subsidiaries of Phillips 66. In July 2017, the Partnership contributed a portion of its ownership interest in Dakota Access and ETCO to PEP, a strategic joint venture with ExxonMobil. ETP continues to consolidate Dakota Access and ETCO subsequent to this transaction.

Results of Operations

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

Segment Adjusted EBITDA, as reported for each segment in the table below, is analyzed for each segment in the section below titled “Segment Operating Results.” Total Segment Adjusted EBITDA, as presented below, is equal to the consolidated measure of Adjusted EBITDA, which is a non- GAAP measure used by industry analysts, investors, lenders and rating agencies to assess the financial performance and the operating results of the Partnership’s fundamental business activities and should not be considered in isolation or as a substitution for net income, income from operations, cash flows from operating activities or other GAAP measures. Our definition of total or consolidated Adjusted EBITDA is consistent with the definition of Segment Adjusted EBITDA above.

Consolidated Results

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Change	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$ 163	$ 133	$ 30	$ 480	$ 461	$ 19
Interstate transportation and storage	273	278	(5)	800	848	(48)
Midstream	356	314	42	1,088	875	213
NGL and refined products transportation and services	423	383	40	1,196	1,072	124
Crude oil transportation and services	396	169	227	830	521	309
All other	133	113	20	363	395	(32)
Total	1,744	1,390	354	4,757	4,172	585
Depreciation, depletion and amortization	(596)	(503)	(93)	(1,713)	(1,469)	(244)
Interest expense, net	(367)	(345)	(22)	(1,052)	(981)	(71)
Losses on interest rate derivatives	(8)	(28)	20	(28)	(179)	151
Non-cash unit-based compensation expense	(19)	(22)	3	(57)	(60)	3
Unrealized gains (losses) on commodity risk management activities	(81)	(15)	(66)	17	(96)	113
Inventory valuation adjustments	86	37	49	30	143	(113)
Adjusted EBITDA related to unconsolidated affiliates	(279)	(240)	(39)	(765)	(711)	(54)
Equity in earnings of unconsolidated affiliates	127	65	62	139	260	(121)
Impairment of investment in an unconsolidated affiliate	—	(308)	308	—	(308)	308
Other, net	42	43	(1)	111	84	27
Income before income tax expense (benefit)	649	74	575	1,439	855	584
Income tax expense (benefit)	(112)	(64)	(48)	22	(131)	153
Net income	$ 761	$ 138	$ 623	$ 1,417	$ 986	$ 431

See the detailed discussion of Segment Adjusted EBITDA and Segment Operating Results.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased for the three and nine months ended September 30, 2017 compared to the same periods last year primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

Interest Expense, net. Interest expense, net of capitalized interest, increased for the three and nine months ended September 30, 2017 compared to the same periods last year primarily attributable to increases in long-term debt, including the Dakota Access and ETCO term loans that became effective in August 2016.

Losses on Interest Rate Derivatives. Losses on interest rate derivatives during the three and nine months ended September 30, 2017 and 2016 resulted from decreases in forward interest rates, which caused our forward-starting swaps to change in value.

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

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for crude oil, NGLs and refined products inventories as a result of commodity price changes during the respective periods.

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

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

Income Tax Expense (Benefit). For the nine months ended September 30, 2017, the Partnership's income tax expense included the impact of a one-time adjustment to deferred tax balances as a result of a change in apportionment and corresponding state tax rates resulting from the Sunoco Logistics Merger in April 2017, which resulted in incremental income tax expense of approximately $68 million during the period. In addition, for the three months ended September 30, 2017, the Partnership recognized a $154 million deferred tax gain resulting from internal restructuring among its subsidiaries that resulted in a change in tax status for one of the subsidiaries. The three and nine months ended September 30, 2017 also reflect increased income tax expense due to higher earnings among the Partnership's consolidated corporate subsidiaries. For the three and nine months ended September 30, 2016, the Partnership's income tax benefit primarily resulted from losses among the Partnership's consolidated corporate subsidiaries.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Change	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$ 35	$ 31	$ 4	$ 86	$ 80	$ 6
FEP	14	12	2	39	38	1
PES	11	(26)	37	5	(25)	30
MEP	9	9	—	29	31	(2)
HPC	5	8	(3)	17	23	(6)
Sunoco LP	35	16	19	(89)	54	(143)
Other	18	15	3	52	59	(7)
Total equity in earnings of unconsolidated affiliates	$ 127	$ 65	$ 62	$ 139	$ 260	$ (121)
Adjusted EBITDA related to unconsolidated affiliates[1]:						
Citrus	$ 99	$ 90	$ 9	$ 262	$ 251	$ 11
FEP	18	19	(1)	55	56	(1)
PES	15	(19)	34	31	2	29
MEP	23	22	1	66	69	(3)
HPC	13	15	(2)	40	45	(5)
Sunoco LP	74	83	(9)	211	208	3
Other	37	30	7	100	80	20
Total Adjusted EBITDA related to unconsolidated affiliates	$ 279	$ 240	$ 39	$ 765	$ 711	$ 54
Distributions received from unconsolidated affiliates:						
Citrus	$ 50	$ 50	$ —	$ 113	$ 112	$ 1
FEP	18	17	1	28	47	(19)
MEP	13	17	(4)	106	56	50
HPC	9	13	(4)	22	38	(16)
Sunoco LP	36	36	—	108	102	6
Other	18	16	2	58	49	9
Total distributions received from unconsolidated affiliates	$ 144	$ 149	$ (5)	$ 435	$ 404	$ 31

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

Segment Operating Results

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

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

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

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

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

For prior periods reported herein, certain transactions related to the business of legacy Sunoco Logistics have been reclassified from cost of products sold to operating expenses; these transactions include sales between operating subsidiaries and their marketing affiliates. These reclassifications had no impact on net income or total equity.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Intrastate transportation and storage	$ 167	$ 172	$ 551	$ 525
Interstate transportation and storage	224	236	666	729
Midstream	530	476	1,614	1,350
NGL and refined products transportation and services	488	484	1,563	1,357
Crude oil transportation and services	588	266	1,202	852
All other	112	79	290	258
Intersegment eliminations	(12)	(26)	(24)	(50)
Total Segment Margin	2,097	1,687	5,862	5,021
Less:				
Operating expenses	571	475	1,603	1,359
Depreciation, depletion and amortization	596	503	1,713	1,469
Selling, general and administrative	105	71	335	226
Operating income	$ 825	$ 638	$ 2,211	$ 1,967

Intrastate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Natural gas transported (MMBtu/d)	8,942,066	8,289,826	652,240	8,695,047	8,392,641	302,406
Revenues	$ 773	$ 758	$ 15	$ 2,342	$ 1,857	$ 485
Cost of products sold	606	586	20	1,791	1,332	459
Segment margin	167	172	(5)	551	525	26
Unrealized (gains) losses on commodity risk management activities	22	(7)	29	16	24	(8)
Operating expenses, excluding non-cash compensation expense	(40)	(43)	3	(124)	(117)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(6)	(5)	(1)	(17)	(17)	—
Adjusted EBITDA related to unconsolidated affiliates	19	15	4	53	45	8
Other	1	1	—	1	1	—
Segment Adjusted EBITDA	$ 163	$ 133	$ 30	$ 480	$ 461	$ 19

Volumes. For the three and nine months ended September 30, 2017 compared to the same periods last year, transported volumes increased primarily due to higher demand for exports to Mexico, along with the addition of new pipes to our intrastate pipeline system. These increases were partially offset by lower production volumes in the Barnett Shale region.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Transportation fees	$ 108	$ 122	$ (14)	$ 337	$ 381	$ (44)
Natural gas sales and other	42	26	16	140	81	59
Retained fuel revenues	14	14	—	48	34	14
Storage margin, including fees	3	10	(7)	26	29	(3)
Total segment margin	$ 167	$ 172	$ (5)	$ 551	$ 525	$ 26

Segment Adjusted EBITDA. For the three months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $29 million in natural gas sales and other (excluding net changes in unrealized gains and losses of $13 million) primarily due to higher realized gains from pipeline optimization activity;
- an increase of $9 million in storage margin (excluding net changes in unrealized gains and losses of $16 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below;
- a decrease of $3 million in operating expenses primarily due to the timing of project related expenses of $3 million, lower allocated expenses and lower capitalized overhead of $2 million, partially offset by higher outside services and employee expenses of $2 million; and
- an increase of $4 million in Adjusted EBITDA related to unconsolidated affiliates due to two new joint venture pipelines placed in service in 2017; partially offset by
- a decrease in transportation fees of $14 million due to renegotiated contracts resulting in lower billed volumes, offset by increased margin from optimization activity recorded in natural gas sales and other.

Segment Adjusted EBITDA. For the nine months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $63 million in natural gas sales and other (excluding net changes in unrealized gains and losses of $4 million) primarily due to higher realized gains from pipeline optimization activity;
- a decrease of $11 million in storage margin (excluding net changes in unrealized gains and losses of $8 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below;
- an increase of $10 million in retained fuel sales (excluding net changes in unrealized gains and losses of $4 million) primarily due to higher market prices. The average spot price at the Houston Ship Channel location increased 34% for the nine months ended September 30, 2017 compared to the same period last year;
- an increase of $7 million in operating expenses primarily due to higher compression fuel expense of $6 million and higher maintenance and general expenses of $7 million, offset by lower allocated expenses of $3 million, lower capitalized overhead of $2 million and timing of project expenses of $1 million; and
- an increase of $8 million in Adjusted EBITDA related to unconsolidated affiliates due to two new joint venture pipelines placed in service in 2017; partially offset by
- a decrease in transportation fees of $44 million due to renegotiated contracts resulting in lower billed volumes, offset by increased margin from optimization activity recorded in natural gas sales and other and an increase of $8 million due to new demand billings on our Houston Pipeline system.

Storage margin was comprised of the following:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Withdrawals from storage natural gas inventory (MMBtu)	—	11,547,500	(11,547,500)	23,092,500	33,205,000	(10,112,500)
Realized margin on natural gas inventory transactions	$ 5	$ (3)	$ 8	$ 18	$ 33	$ (15)
Fair value inventory adjustments	(10)	(4)	(6)	(46)	52	(98)
Unrealized gains (losses) on derivatives	2	12	(10)	34	(74)	108
Margin recognized on natural gas inventory, including related derivatives	(3)	5	(8)	6	11	(5)
Revenues from fee-based storage	6	5	1	20	18	2
Total storage margin	$ 3	$ 10	$ (7)	$ 26	$ 29	$ (3)

The changes in storage margin were due primarily to the movement in market price of the physical storage gas and the financial derivatives used to hedge that gas.

Interstate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Natural gas transported (MMBtu/d)	6,074,783	5,385,679	689,104	5,678,016	5,527,607	150,409
Natural gas sold (MMBtu/d)	19,012	19,478	(466)	17,659	19,398	(1,739)
Revenues	$ 224	$ 236	$ (12)	$ 666	$ 729	$ (63)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(79)	(76)	(3)	(220)	(223)	3
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(14)	(13)	(1)	(33)	(36)	3
Adjusted EBITDA related to unconsolidated affiliates	140	131	9	383	376	7
Other	2	—	2	4	2	2
Segment Adjusted EBITDA	$ 273	$ 278	$ (5)	$ 800	$ 848	$ (48)

Volumes. For the three months ended September 30, 2017 compared to the same period last year, transported volumes reflected increases of 157,060 MMBtu/d on the Trunkline pipeline as a result of increased backhaul deliveries, 153,401 MMBtu/d on the Tiger pipeline due to an increase in production in the Haynesville Shale, and 142,207 MMBtu/d on the Transwestern pipeline as a result of weather driven demand in the West and opportunities in the Texas intrastate market. The remainder of the increase was primarily due to the Rover pipeline, which was placed in partial service on August 31, 2017.

For the nine months ended September 30, 2017 compared to the same period last year, transported volumes increased due to the placement in partial service of the Rover pipeline effective August 31, 2017 and 59,305 MMBtu/d on the Tiger pipeline due to an increase in production in the Haynesville Shale and opportunities in the Texas intrastate market.

Segment Adjusted EBITDA. For the three months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net effect of the following:

- a decrease in reservation revenues of $16 million on the Panhandle, Trunkline and Transwestern pipelines and a decrease of $3 million in gas parking service related revenues on the Panhandle and Trunkline pipelines, primarily due to lack of customer demand driven by weak spreads and mild weather. In addition, revenues on the Tiger pipeline decreased $3 million due to contract restructuring. These decreases were offset by $10 million of revenues from the placement in partial service of the Rover pipeline effective August 31, 2017; and
- an increase in operating expenses of $3 million primarily due to higher ad valorem taxes resulting from higher valuations; offset by
- an increase in income from unconsolidated joint ventures of $9 million primarily due to a legal settlement and lower operating expenses on Citrus.

Segment Adjusted EBITDA. For the nine months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net effect of the following:

- a decrease in reservation revenues of $41 million on the Panhandle, Trunkline and Transwestern pipelines and a decrease of $11 million in gas parking service related revenues on the Panhandle and Trunkline pipelines, primarily due to lack of customer demand driven by weak spreads and mild weather, decrease of $17 million in revenues on the Tiger pipeline due to contract restructuring, and a decrease of $4 million on the Sea Robin pipeline due to producer maintenance and production declines. The decreases above were offset by $10 million of revenues from the placement in partial service of the Rover pipeline effective August 31, 2017;
- a decrease in operating expenses of $3 million primarily due to lower allocated costs of $7 million and lower lease storage expense of $3 million, partially offset by higher ad valorem taxes resulting from higher valuations; and
- a decrease in selling, general and administrative expenses of $3 million due to refunds associated with legal fees, insurance premiums and franchise taxes; offset by

- an increase in income from unconsolidated joint ventures of $7 million primarily due to a legal settlement and lower operating expenses on Citrus, partially offset by lower earnings from Midcontinent Express.

Midstream

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Change	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Change
Gathered volumes (MMBtu/d)	11,090,285	9,675,003	1,415,282	10,764,317	9,853,930	910,387
NGLs produced (Bbls/d)	449,454	420,877	28,577	442,190	440,124	2,066
Equity NGLs (Bbls/d)	27,185	34,341	(7,156)	26,936	31,847	(4,911)
Revenues	$ 1,765	$ 1,343	$ 422	$ 5,017	$ 3,765	$ 1,252
Cost of products sold	1,235	867	368	3,403	2,415	988
Segment margin	530	476	54	1,614	1,350	264
Unrealized (gains) losses on commodity risk management activities	1	—	1	(18)	—	(18)
Operating expenses, excluding non-cash compensation expense	(157)	(153)	(4)	(470)	(453)	(17)
Selling, general and administrative expenses, excluding non-cash compensation expense	(26)	(17)	(9)	(60)	(42)	(18)
Adjusted EBITDA related to unconsolidated affiliates	6	7	(1)	20	19	1
Other	2	1	1	2	1	1
Segment Adjusted EBITDA	$ 356	$ 314	$ 42	$ 1,088	$ 875	$ 213

Volumes. Gathered volumes and NGL production increased during the three and nine months ended September 30, 2017 compared to the same periods last year primarily due to recent acquisitions, including PennTex, and gains in the Permian and Northeast regions, partially offset by basin declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions.

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

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Change	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Change
Gathering and processing fee-based revenues	$ 422	$ 391	$ 31	$ 1,264	$ 1,171	$ 93
Non fee-based contracts and processing	108	85	23	350	179	171
Total segment margin	$ 530	$ 476	$ 54	$ 1,614	$ 1,350	$ 264

Segment Adjusted EBITDA. For the three months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net effects of the following:

- an increase of $24 million (excluding net changes in unrealized gains and losses of $1 million) in non-fee based margin due to higher crude oil and NGL prices;
- an increase of $16 million in fee-based revenue due to minimum volume commitments in the South Texas region, as well as volume increases in the Permian and Northeast regions. These increases were partially offset by volume declines in South Texas, North Texas and the Mid-Continent/Panhandle regions; and
- an increase of $15 million in fee-based revenue due to recent acquisitions, including PennTex; partially offset by
- an increase of $4 million in operating expenses primarily due to recent acquisitions, including PennTex; and
- an increase in selling, general and administrative expenses primarily due to an increase in shared services allocation.

Segment Adjusted EBITDA. For the nine months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net effects of the following:

- an increase of $113 million in non-fee based margin due to higher crude oil and NGL prices;
- an increase of $38 million (excluding net changes in unrealized gains and losses of $20 million) in non-fee based margin due to volume increases in the Permian, partially offset by declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions;
- an increase of $36 million in fee-based revenue due to minimum volume commitments in the South Texas region, as well as volume increases in the Permian and Northeast regions. These increases were partially offset by volume declines in the South Texas, North Texas and the Mid-Continent/Panhandle regions; and
- an increase of $57 million in fee-based revenue due to recent acquisitions, including PennTex; partially offset by
- an increase of $17 million in operating expenses primarily due to recent acquisitions, including PennTex; and
- an increase of $18 million in general and administrative expenses primarily due to a decrease of $8 million in capitalized overhead, a $13 million increase in shared services allocation and $6 million additional costs from the PennTex acquisition. These increases were partially offset by a favorable impact of $12 million from the adjustment of certain reserves that had previously been recorded in connection with contingent matters.

NGL and Refined Products Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
NGL transportation volumes (MBbls/d)	836	766	70	827	741	86
Refined products transportation volumes (MBbls/d)	612	611	1	626	573	53
NGL and refined products terminal volumes (MBbls/d)	782	822	(40)	793	782	11
NGL fractionation volumes (MBbls/d)	390	338	52	418	350	68
Revenues	$ 2,070	$ 1,545	$ 525	$ 6,115	$ 4,329	$ 1,786
Cost of products sold	1,582	1,061	521	4,552	2,972	1,580
Segment margin	488	484	4	1,563	1,357	206
Unrealized losses on commodity risk management activities	56	21	35	2	53	(51)
Operating expenses, excluding non-cash compensation expense	(105)	(109)	4	(358)	(319)	(39)
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(12)	(1)	(49)	(41)	(8)
Adjusted EBITDA related to unconsolidated affiliates	19	21	(2)	54	53	1
Inventory valuation adjustments	(22)	(22)	—	(17)	(31)	14
Other	—	—	—	1	—	1
Segment Adjusted EBITDA	$ 423	$ 383	$ 40	$ 1,196	$ 1,072	$ 124

Volumes. For the three and nine months ended September 30, 2017 compared to the same periods last year, NGL and refined products transportation volumes increased in the major producing regions, including the Permian, Southeast Texas, Louisiana, Eagle Ford and North Texas.

NGL and refined products terminal volumes decreased for the three months ended September 30, 2017 primarily due to the sale of one of our refined product terminals in April 2017. NGL and refined products terminal volumes increased for the nine months ended September 30, 2017 primarily due to increased throughput at our Marcus Hook Industrial Complex from the Northeast producing regions.

Average daily fractionated volumes increased 17% and 23% for the three and nine months ended September 30, 2017, respectively, compared to the same periods last year primarily due to the commissioning of our fourth fractionator at Mont Belvieu, Texas, in October 2016, which has a capacity of 120,000 Bbls/d, as well as increased producer volumes as mentioned above.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Fractionators and Refinery services margin	$ 117	$ 103	$ 14	$ 352	$ 296	$ 56
Transportation margin	246	226	20	720	629	91
Storage margin	50	50	—	160	148	12
Terminal Services margin	90	83	7	258	239	19
Marketing margin	(15)	22	(37)	73	45	28
Total segment margin	$ 488	$ 484	$ 4	$ 1,563	$ 1,357	$ 206

Segment Adjusted EBITDA. For the three months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impact of the following:

- an increase in transportation margin of $20 million primarily due to higher volumes on our Texas NGL pipelines and our Mariner East system;
- an increase in fractionation and refinery services margin of $13 million (excluding net changes in unrealized gains and losses of $1 million) primarily due to higher NGL volumes from most major producing regions, as noted above;
- an increase in terminal services margin of $7 million due to higher terminal volumes from the Mariner NGL projects; and
- a decrease of $4 million in operating expenses primarily due to a legal settlement of $8 million and a quarterly ad valorem tax true-up of $1 million; partially offset by
- a decrease of $1 million in marketing margin (excluding net changes in unrealized gains and losses of $36 million) primarily due to the timing of the recognition of margin from optimization activities; and
- an increase of $1 million in selling, general and administrative expenses due to higher allocations and lower capitalized overhead resulting from reduced capital spending.

Segment Adjusted EBITDA. For the nine months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impact of the following:

- an increase in storage margin of $12 million primarily due to increased volumes from our Mont Belvieu fractionators;
- an increase in transportation margin of $91 million primarily due to higher volumes on our Texas NGL pipelines and our Mariner East system;
- an increase in fractionation and refinery services margin of $55 million (excluding net changes in unrealized gains and losses of $1 million) primarily due to higher NGL volumes from most major producing regions, as noted above;
- an increase in terminal services margin of $19 million due to higher terminal volumes from the Mariner NGL projects; and
- an increase of $22 million in marketing margin (excluding net changes in unrealized gains and losses of $50 million) primarily due to the timing of the recognition of margin from optimization activities; partially offset by
- an increase of $39 million in operating expenses primarily due to increased utilities costs associated with our fourth fractionator at Mont Belvieu and the Mariner project ramp up at the Marcus Hook Industrial Complex of $15 million, higher ad valorem tax expenses of $11 million (primarily from our Lone Star Express pipeline beginning service in 2016), higher employee expenses associated with assets placed in service of $5 million and project related service expenses of $5 million; and
- an increase of $8 million in selling, general and administrative expenses due to higher allocations and lower capitalized overhead resulting from reduced capital spending.

Crude Oil Transportation and Services

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Change	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Change
Crude Transportation Volumes (MBbls/d)	3,758	2,686	1,072	3,401	2,500	901
Crude Terminals Volumes (MBbls/d)	1,923	1,559	364	1,877	1,524	353
Revenues	$ 2,725	$ 1,856	$ 869	$ 7,765	$ 5,146	$ 2,619
Cost of products sold	2,137	1,590	547	6,563	4,294	2,269
Segment margin	588	266	322	1,202	852	350
Unrealized gains on commodity risk management activities	(1)	—	(1)	(3)	—	(3)
Operating expenses, excluding non-cash compensation expense	(119)	(71)	(48)	(305)	(185)	(120)
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(16)	3	(62)	(44)	(18)
Adjusted EBITDA related to unconsolidated affiliates	5	5	—	11	10	1
Inventory valuation adjustments	(64)	(15)	(49)	(13)	(112)	99
Segment Adjusted EBITDA	$ 396	$ 169	$ 227	$ 830	$ 521	$ 309

Segment Adjusted EBITDA. For the three months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the following:

- an increase of $194 million resulting primarily from placing our Bakken Pipeline in service in the second quarter of 2017, as well as the acquisition of a crude oil gathering system in West Texas;
- an increase of $28 million from existing assets due to increased volumes throughout the system; and
- an increase of $18 million due to the impact of LIFO accounting; partially offset by
- additional operating expense as a result of placing other new projects in service and costs associated with increased volumes on our system.

Segment Adjusted EBITDA. For the nine months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the following:

- an increase of $389 million resulting primarily from placing our Bakken Pipeline in service in the second quarter of 2017, as well as the acquisition of a crude oil gathering system in West Texas; and
- an increase of $11 million from existing assets due to increased volumes throughout the system; partially offset by
- a decrease of $29 million due to the impact of LIFO accounting. This unfavorable LIFO impact is expected to be reversed in future periods as commodity prices fall or the inventory positions are liquidated; and
- additional operating expense as a result of placing other new projects in service and costs associated with increased volumes on our system.

All Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Revenues	$ 683	$ 956	$ (273)	$ 2,249	$ 2,521	$ (272)
Cost of products sold	571	877	(306)	1,959	2,263	(304)
Segment margin	112	79	33	290	258	32
Unrealized (gains) losses on commodity risk management activities	3	1	2	(14)	19	(33)
Operating expenses, excluding non-cash compensation expense	(34)	(20)	(14)	(86)	(57)	(29)
Selling, general and administrative expenses, excluding non-cash compensation expense	(34)	(14)	(20)	(82)	(60)	(22)
Adjusted EBITDA related to unconsolidated affiliates	88	63	25	244	209	35
Other and eliminations	(2)	4	(6)	11	26	(15)
Segment Adjusted EBITDA	$ 133	$ 113	$ 20	$ 363	$ 395	$ (32)

Amounts reflected in our all other segment primarily include:

- our equity method investment in limited partnership units of Sunoco LP consisting of 43.5 million units, representing 43.7% of Sunoco LP’s total outstanding common units;
- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities.

Segment Adjusted EBITDA. For the three months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment increased primarily due to the net impact of the following:

- an increase of $25 million in Adjusted EBITDA related to unconsolidated affiliates, reflecting an increase of $34 million from our investment in PES, offset by a decrease of $9 million from our investment in Sunoco LP;
- an increase of $7 million from commodity trading activities; and
- an increase of $4 million from our compression operations; partially offset by
- an increase of $11 million in transaction related expenses; and
- an increase of $9 million in operating expenses related to an equipment lease buyout.

Segment Adjusted EBITDA. For the nine months ended September 30, 2017 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment decreased primarily due to the net impact of the following:

- a decrease of $66 million related to the termination of management fees paid by ETE that ended in 2016; and
- an increase of $39 million in transaction related expenses; partially offset by
- an increase of $35 million in Adjusted EBITDA related to unconsolidated affiliates, primarily comprising increases of $29 million from our investment in PES and $3 million from our investment in Sunoco LP;
- an increase of $15 million from commodity trading activities; and
- lower expenses related to our compression operations.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

For the year ending December 31, 2017, we expect to spend approximately $4.1 billion on capital expenditure funding, net of $1.0 billion financed at the asset level and net an approximately $1.4 billion reduction related to the sale of a portion of our interest in the Rover pipeline project. For 2018, we expect to spend approximately $3 billion on organic growth projects.

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

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional common units, dropdown proceeds or the monetization of non-core assets or a combination thereof.

Cash Flows

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

Operating Activities

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

Nine months ended September 30, 2017 compared to nine months ended September 30, 2016. Cash provided by operating activities during 2017 was $3.34 billion compared to $2.47 billion for 2016 and net income was $1.42 billion and $986 million for 2017 and 2016, respectively. The difference between net income and cash provided by operating activities for the nine months ended September 30, 2017 primarily consisted of net changes in operating assets and liabilities of $185 million and non-cash items totaling $1.44 billion.

The non-cash activity in 2017 and 2016 consisted primarily of depreciation, depletion and amortization of $1.71 billion and $1.47 billion, respectively, non-cash compensation expense of $57 million and $60 million, respectively, and equity in earnings of unconsolidated affiliates of $139 million and $260 million, respectively. Non-cash activity in 2017 also included deferred income taxes of $1 million and inventory valuation adjustments of $30 million. Non-cash activity in 2016 also included impairment of investment in an unconsolidated affiliate of $308 million.

Cash paid for interest, net of interest capitalized, was $1.03 billion and $1.10 billion for the nine months ended September 30, 2017 and 2016, respectively.

Capitalized interest was $177 million and $148 million for the nine months ended September 30, 2017 and 2016, respectively.

Investing Activities

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

Nine months ended September 30, 2017 compared to nine months ended September 30, 2016. Cash used in investing activities during 2017 was $4.69 billion compared to $3.64 billion for 2016. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2017 were $6.06 billion compared to $5.74 billion for 2016. Additional detail related to our capital expenditures is provided in the table below. During 2017, we received $2.00 billion in cash related to the Bakken equity sale to MarEn Bakken Company, paid $280 million in cash for the acquisition of PennTex noncontrolling interest, and paid $264 million in cash for all other acquisitions. During 2016, we received $2.20 billion in cash related to the contribution of our Sunoco, Inc. retail business to Sunoco LP.

The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the nine months ended September 30, 2017:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$ 34	$ 22	$ 56
Interstate transportation and storage	1,704	50	1,754
Midstream	914	76	990
NGL and refined products transportation and services	2,106	53	2,159
Crude oil transportation and services	331	36	367
All other (including eliminations)	128	49	177
Total capital expenditures	$ 5,217	$ 286	$ 5,503

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures.

Nine months ended September 30, 2017 compared to nine months ended September 30, 2016. Cash provided by financing activities during 2017 was $1.37 billion compared to $1.03 billion for 2016. In 2017 and 2016, we received net proceeds from Common Unit offerings of $2.16 billion and $794 million, respectively. In 2016, our subsidiaries received $1.31 billion in net proceeds from the issuance of common units. During 2017, we had a net increase in our debt level of $1.24 billion compared to a net increase of $1.76 billion for 2016. We have paid distributions of $2.54 billion to our partners in 2017 compared to $2.67 billion in 2016. We have also paid distributions of $306 million to noncontrolling interests in 2017 compared to $334 million in 2016. In addition, we have received capital contributions of $919 million in cash from noncontrolling interests in 2017 compared to $187 million in 2016. During 2017, we repurchased our outstanding Preferred Units for cash of $53 million and incurred debt issuance costs of $50 million.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2017	December 31, 2016
ETP Senior Notes	$ 20,540	$ 19,440
Transwestern Senior Notes	575	657
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	65	465
Sunoco Logistics Senior Notes	7,600	5,350
Credit facilities and commercial paper:		
ETLP $3.75 billion Revolving Credit Facility due November 2019[1]	2,056	2,777
Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020[2]	35	1,292
Sunoco Logistics $1.00 billion 364-Day Credit Facility due December 2017[3]	—	630
Bakken Project $2.50 billion Credit Facility due August 2019	2,500	1,100
PennTex $275 million Revolving Credit Facility due December 2019	—	168
Other long-term debt	5	30
Unamortized premiums, net of discounts and fair value adjustments	76	116
Deferred debt issuance costs	(197)	(180)
Total debt	34,340	32,930
Less: current maturities of long-term debt	710	1,189
Long-term debt, less current maturities	$ 33,630	$ 31,741

(1) Includes $2.06 billion and $777 million of commercial paper outstanding at September 30, 2017 and December 31, 2016, respectively.

(2) Includes $50 million of commercial paper outstanding at December 31, 2016.

(3) Sunoco Logistics' $1.00 billion 364-Day Credit Facility, including its $630 million term loan, were classified as long-term debt as of December 31, 2016 as Sunoco Logistics had the ability and intent to refinance such borrowings on a long-term basis. This 364-Day Credit Facility was terminated and repaid in May 2017.

ETP Senior Notes Redemption

In October 2017, the Partnership redeemed all of the outstanding $500 million aggregate principal amount of ETLP's 6.50% senior notes due July 2021 and all of the outstanding $700 million aggregate principal amount of ETLP's 5.50% senior notes due April 2023. The aggregate amount paid to redeem these notes, including call premiums, was approximately $1.23 billion.

ETP Senior Notes Offering

In September 2017, Sunoco Logistics Partners Operations L.P., a subsidiary of ETP, issued $750 million aggregate principal amount of 4.00% senior notes due 2027 and $1.50 billion aggregate principal amount of 5.40% senior notes due 2047. The $2.22 billion net proceeds from the offering were used to redeem all of the $500 million aggregate principal amount of ETLP's 6.5% senior notes due 2021, to repay borrowings outstanding under the Sunoco Logistics Credit Facility (described below) and for general partnership purposes.

Credit Facilities and Commercial Paper

ETLP Credit Facility

The ETLP Credit Facility allows for borrowings of up to $3.75 billion and matures in November 2019. The indebtedness under the ETLP Credit Facility is unsecured, is not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. In September 2016, ETLP initiated a commercial paper program under the borrowing limits established by the $3.75 billion ETLP Credit Facility. As of September 30, 2017, the ETLP Credit Facility had $2.06 billion of outstanding borrowings, all of which was commercial paper.

Sunoco Logistics Credit Facilities

ETP maintains the Sunoco Logistics $2.50 billion unsecured revolving credit facility (the "Sunoco Logistics Credit Facility"), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $3.25 billion under certain conditions. As of September 30, 2017, the Sunoco Logistics Credit Facility had $35 million of outstanding borrowings.

In December 2016, Sunoco Logistics entered into an agreement for a 364-day maturity credit facility ("364-Day Credit Facility"), due to mature on the earlier of the occurrence of the Sunoco Logistics Merger or in December 2017, with a total lending capacity of $1.00 billion. In connection with the Sunoco Logistics Merger, the 364-Day Credit Facility was terminated and repaid in May 2017.

Bakken Credit Facility

In August 2016, Energy Transfer Partners, L.P., Sunoco Logistics and Phillips 66 completed project-level financing of the Bakken Pipeline. The $2.50 billion credit facility provides substantially all of the remaining capital necessary to complete the projects. As of September 30, 2017, $2.50 billion was outstanding under this credit facility.

PennTex Revolving Credit Facility

PennTex previously maintained a $275 million revolving credit commitment (the "PennTex Revolving Credit Facility"). In August 2017, the PennTex Revolving Credit Facility was repaid and terminated.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of September 30, 2017.

CASH DISTRIBUTIONS

Following the Sunoco Logistics Merger, cash distributions are declared and paid in accordance with the Partnership's limited partnership agreement, which was Sunoco Logistics' limited partnership agreement prior to the Sunoco Logistics Merger. Under the agreement, within 45 days after the end of each quarter, the Partnership distributes all cash on hand at the end of the quarter, less reserves established by the general partner in its discretion. This is defined as "available cash" in the partnership agreement. The general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct the Partnership's business. The Partnership will make quarterly distributions to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to the general partner.

If cash distributions exceed $0.0833 per unit in a quarter, the general partner receives increasing percentages, up to 50 percent, of the cash distributed in excess of that amount. These distributions are referred to as "incentive distributions." The percentage interests shown for the unitholders and the general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

The following table shows the target distribution levels and distribution "splits" between the general partner and the holders of the Partnership's common units:

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	IDRs	Partners [1]
Minimum Quarterly Distribution	$0.0750	—%	100%
First Target Distribution	up to $0.0833	—%	100%
Second Target Distribution	above $0.0833 up to $0.0958	13%	87%
Third Target Distribution	above $0.0958 up to $0.2638	35%	65%
Thereafter	above $0.2638	48%	52%

(1) Includes general partner and limited partner interests, based on the proportionate ownership of each.

For the quarter ended December 31, 2016, Energy Transfer Partners, L.P. and Sunoco Logistics paid distributions on February 14, 2017 of $0.7033 and $0.52, respectively, per common unit.

Following are distributions declared and/or paid by the Partnership subsequent to the Sunoco Logistics Merger:

Quarter Ended	Record Date	Payment Date	Rate
March 31, 2017	May 10, 2017	May 15, 2017	$ 0.5350
June 30, 2017	August 7, 2017	August 14, 2017	0.5500
September 30, 2017	November 7, 2017	November 14, 2017	0.5650

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

	Nine Months Ended September 30,		
	2017	2016	
	ETP	Energy Transfer Partners, L.P.	Sunoco Logistics
Limited Partners:			
Common Units held by public	$ 1,794	$ 1,607	$ 353
Common Units held by ETP	—	—	100
Common Units held by ETE	45	8	—
Class H Units held by ETE	—	263	—
General Partner interest	12	24	11
Incentive distributions held by ETE	1,204	1,012	289
IDR relinquishments	(482)	(271)	(8)
Total distributions declared to partners	$ 2,573	$ 2,643	$ 745

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The Partnership's critical accounting policies have not changed subsequent to those reported in Exhibit 99.3 to its Form 8-K filed on May 8, 2017. The following information is provided to supplement the Form 8-K disclosures specifically related to impairment of long-lived assets and goodwill.

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

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

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

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in Exhibit 99.3 to the Partnership's Current Report on Form 8-K filed with the SEC on May 8, 2017, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed for the year ended December 31, 2016. Since December 31, 2016, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power, and barrels for natural gas liquids, crude and refined products. Dollar amounts are presented in millions.

	September 30, 2017			December 31, 2016		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	1,297,500	$ —	$ —	(682,500)	$ —	$ —
Basis Swaps IFERC/NYMEX[(1)]	(15,810,000)	(4)	—	2,242,500	(1)	—
Options – Puts	13,000,000	—	—	—	—	—
Power (Megawatt):						
Forwards	665,040	—	2	391,880	(1)	1
Futures	(213,840)	—	1	109,564	—	—
Options – Puts	(280,800)	1	2	(50,400)	—	—
Options – Calls	545,600	—	1	186,400	1	—
Crude (Bbls) – Futures	(160,000)	1	1	(617,000)	(4)	6
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	67,500	(3)	2	10,750,000	2	—
Swing Swaps IFERC	91,897,500	(1)	—	(5,662,500)	(1)	1
Fixed Swaps/Futures	(20,220,000)	1	7	(52,652,500)	(27)	19
Forward Physical Contracts	(140,937,993)	3	43	(22,492,489)	1	8
Natural Gas Liquid (Bbls) – Forwards/Swaps	(8,747,200)	(48)	79	(5,786,627)	(40)	35
Refined Products (Bbls) – Futures	(701,000)	—	9	(2,240,000)	(16)	17
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(41,102,500)	2	—	(36,370,000)	2	1
Fixed Swaps/Futures	(41,102,500)	5	12	(36,370,000)	(26)	14

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

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

Interest Rate Risk

As of September 30, 2017, we had $5.20 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $52 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding (dollars in millions), none of which are designated as hedges for accounting purposes:

		Notional Amount Outstanding	
Term	Type[(1)]	September 30, 2017	December 31, 2016
July 2017[(2)]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	$ —	$ 500
July 2018[(2)]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	300	200
July 2019[(2)]	Forward-starting to pay a fixed rate of 3.64% and receive a floating rate	300	200
July 2020[(2)]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	—
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300

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

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

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $237 million as of September 30, 2017. For the $1.50 billion of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $19 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms.

Under the supervision and with the participation of senior management, including the Chief Executive Officer (“Principal Executive Officer”) and the Chief Financial Officer (“Principal Financial Officer”) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of September 30, 2017 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

As a result of the Sunoco Logistics Merger, which was completed in April 2017, our internal control over financial reporting now includes the controls of Energy Transfer, LP (formerly named “Energy Transfer Partners, L.P.”). The internal control over financial reporting of Energy Transfer, LP was evaluated by Energy Transfer, LP's management (which is now the Partnership's management) as of December 31, 2016 under the same framework that the Partnership's internal control over financial reporting was evaluated, and Energy Transfer, LP's management concluded that its internal control over financial reporting was effective as of December 31, 2016.

There have been no other changes in our internal controls over financial reporting (as defined in Rule 13(a)–15(f) or Rule 15d–15(f) of the Exchange Act) during the three months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Exhibit 99.3 to our Current Report on Form 8-K filed with the SEC on May 8, 2017 and Note 11 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2017.

The EPA has brought a federal court action against SPLP and Mid-Valley for violations of the Clean Water Act ("CWA"). The United States' complaint alleges that SPLP and Mid-Valley violated Sections 311(b)(7)(A) and 301(a) of the CWA when, during three separate releases, pipelines operated by SPLP and owned by SPLP or Mid-Valley Pipeline Company discharged oil. See 33 U.S.C. §§ 1311(a) and 1321(b)(7)(A). In particular, the three releases at issue occurred (1) on February 23, 2013, in Tyler County, Texas, when a reported 550 barrels of oil were discharged; (2) on October 13, 2014, in Caddo Parish, Louisiana, when a reported 4,509 barrels of oil were discharged; and (3) on January 20, 2015, in Grant County, Oklahoma, when a reported 40 barrels of oil were discharged. Potential fines from the DOJ are $7 million and from the State of Louisiana are approximately $1 million. The Partnership is currently in discussions to resolve these matters.

Mont Belvieu received a Notice of Enforcement ("NOE") with an Agreed Order from the Texas Commission on Environmental Quality and has a pending settlement for $0.01 million. The NOE was for the two violations.

Energy Transfer Company Field Services, LLC received a settlement agreement and a stipulated final compliance order from the New Mexico Environmental Department ("NMED") on October 12, 2017 for allegations of violations of New Mexico air regulations related to Jal #3 facilities. This order is a combination of Notice of Violation REG-0569-1402-R1 and Notice of Violation REG-0569-1601. The alleged violations occurred during the periods of March 24, 2014 through September 30, 2014 and September 1, 2016 through December 31, 2016. The settlement includes a civil penalty in the amount of $0.4 million and a supplement environmental project in the amount of $0.8 million.

Energy Transfer Company Field Services, LLC received a settlement offer from the NMED on June 6, 2017 for allegations of violations of New Mexico air regulations related to Jal #3 facilities. The alleged violation occurred during the period of January 1, 2017 through September 11, 2017. The NMED is offering to settle the violations with a civil penalty of $0.6 million.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors described in Part I, Item 1A in our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2016 and in Exhibit 99.3 to our Current Report on Form 8-K filed with the SEC on May 8, 2017.

ITEM 6. EXHIBITS

The exhibits listed below are filed or furnished, as indicated, as part of this report:

Exhibit Number	Description
2.1	Contribution Agreement, dated as of July 30, 2017, by and among Energy Transfer Interstate Holdings, LLC, ET Rover Pipeline LLC and BCP Renaissance, L.L.C. (incorporated by reference to Exhibit 2.1 of Form 8-K, File No. 1-31219, filed August 2, 2017).
3.1	Certificate of Limited Partnership of Sunoco Logistics Partners L.P. (incorporated by reference to Exhibit 3.1 of Form S-1 Registration Statement, File No. 333-71968, filed October 22, 2001).
3.2	Amendment to the Certificate of Limited Partnership of Sunoco Logistics Partners L.P. dated as of August 28, 2015 (incorporated by reference to Exhibit 3.1 of Form 8-K, File No. 1-31219, filed September 1, 2015).
3.3	Amendment to the Certificate of Limited Partnership of Sunoco Logistics Partners L.P. dated as of April 28, 2017 (incorporated by reference to Exhibit 3.3 of Form 8-K, File No. 1-31219, filed April 28, 2017).
3.4	Fourth Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated April 28, 2017 (incorporated by reference to Exhibit 3.4 of Form 8-K, File No. 1-31219, filed April 28, 2017).
4.1	Fifteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.2 of Form 8-K, File No. 1-31219, filed September 25, 2017).
4.2	Form of 4.000% Senior Notes due 2027 (incorporated by reference to Exhibit A to Exhibit 4.2 of Form 8-K, File No. 1-31219, filed September 25, 2017).
4.3	Sixteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.4 of Form 8-K, File No. 1-31219, filed September 25, 2017).
4.4	Form of 5.400% Senior Notes due 2047 (incorporated by reference to Exhibit A to Exhibit 4.4 of Form 8-K, File No. 1-31219, filed September 25, 2017).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith.
**	Furnished herewith.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P.
its General Partner

By: Energy Transfer Partners, L.L.C.
its General Partner

Date: November 7, 2017

By: /s/ A. Troy Sturrock
A. Troy Sturrock
Senior Vice President, Controller and Principal Accounting Officer
(duly authorized to sign on behalf of the registrant)

Exhibit 12.1

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

	Nine Months Ended September 30, 2017	
	Energy Transfer Partners, L.P. (consolidated)	Sunoco Logistics Partners Operations L.P.
Fixed Charges:		
Interest expense, net	$ 1,052	$ 101
Capitalized interest	177	121
Interest charges included in rental expense	7	3
Total fixed charges	1,236	225
Earnings:		
Income before income tax expense and noncontrolling interest	1,439	959
Less: equity in earnings of unconsolidated affiliates	(139)	(58)
Total earnings	1,300	901
Add:		
Fixed charges	1,236	225
Amortization of capitalized interest	15	3
Distributed income of equity investees	319	48
Less:		
Interest capitalized	(177)	(121)
Income available for fixed charges	$ 2,693	$ 1,056
Ratio of earnings to fixed charges	2.18	4.69

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kelcy L. Warren, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Thomas E. Long, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ Thomas E. Long
Thomas E. Long
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended September 30, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kelcy L. Warren, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 7, 2017

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer, LP and furnished to the Securities and Exchange Commission upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Energy Transfer Partners, L.P. (the “Partnership”) on Form 10-Q for the quarter ended September 30, 2017, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Thomas E. Long, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 7, 2017

/s/ Thomas E. Long

Thomas E. Long

Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to and will be retained by Energy Transfer, LP and furnished to the Securities and Exchange Commission upon request.