Energy Transfer Operating, L.P.
Form 10-Q
November 08, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number 1-31219
ENERGY TRANSFER OPERATING, L.P.
(Exact name of registrant as specified in its charter)

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

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)
(214) 981-0700
(Registrant’s telephone number, including area code)
Energy Transfer Partners, L.P.
(Former name, former address and former fiscal year, if changed since last report)
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ý 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	ý	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨
		Emerging growth company	¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Operating, L.P. (the “Partnership” or “ETP”) in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “estimate,” “goal,” “ “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership’s actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Part I – Item 1A. Risk Factors” in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2017 filed with the Securities and Exchange Commission on February 23, 2018, “Part II – Item 1A. Risk Factors,” in the Partnership’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 filed on May 10, 2018 and “Part II – Item 1A. Risk Factors,” in the Partnership’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed on August 9, 2018.

Definitions

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

/d	per day
AOCI	accumulated other comprehensive income (loss)
BBtu	billion British thermal units
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
CDM	CDM Resource Management LLC and CDM Environmental & Technical Services LLC, collectively
Citrus	Citrus, LLC
DOJ	United States Department of Justice
EPA	United States Environmental Protection Agency
ETC OLP	La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP

ETP Holdco	ETP Holdco Corporation
ETP LLC	Energy Transfer Partners, L.L.C., the general partner of ETP GP
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC
GAAP	accounting principles generally accepted in the United States of America
HPC	RIGS Haynesville Partnership Co.
IDRs	incentive distribution rights

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Lake Charles LNG	Lake Charles LNG Company, LLC
Legacy ETP Preferred Units	legacy ETP Series A cumulative convertible preferred units
LIBOR	London Interbank Offered Rate
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
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
PennTex	PennTex Midstream Partners, LP
PES	Philadelphia Energy Solutions
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, LLC, a wholly-owned subsidiary of Sunoco, Inc.
RIGS	Regency Intrastate Gas LP
Rover	Rover Pipeline LLC, a subsidiary of ETP
SEC	Securities and Exchange Commission
Series A Preferred Units	6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series B Preferred Units	6.625% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series C Preferred Units	7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series D Preferred Units	7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units

Sunoco Logistics	Sunoco Logistics Partners L.P.
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC, a subsidiary of Panhandle
USAC	USA Compression Partners, LP

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. Adjusted EBITDA reflects amounts for less than wholly-owned subsidiaries based on 100% of the subsidiaries' results of operations and for unconsolidated affiliates based on the Partnership's proportionate ownership.

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PART I – FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	September 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 379	$ 306
Accounts receivable, net	3,671	3,946
Accounts receivable from related companies	333	318
Inventories	1,507	1,589
Income taxes receivable	169	135
Derivative assets	93	24
Other current assets	201	210
Total current assets	6,353	6,528
Property, plant and equipment	70,966	67,699
Accumulated depreciation and depletion	(10,416)	(9,262)
	60,550	58,437
Advances to and investments in unconsolidated affiliates	3,599	3,816
Other non-current assets, net	863	758
Intangible assets, net	4,925	5,311
Goodwill	2,866	3,115
Total assets	$ 79,156	$ 77,965

The accompanying notes are an integral part of these consolidated financial statements.
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ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	September 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,381	$ 4,126
Accounts payable to related companies	287	209
Derivative liabilities	338	109
Accrued and other current liabilities	2,603	2,143
Current maturities of long-term debt	2,649	407
Total current liabilities	9,258	6,994
Long-term debt, less current maturities	31,198	32,687
Non-current derivative liabilities	57	145
Deferred income taxes	2,845	2,883
Other non-current liabilities	1,100	1,084
Commitments and contingencies		
Redeemable noncontrolling interests	22	21
Equity:		
Limited Partners:		
Series A Preferred Unitholders	944	944
Series B Preferred Unitholders	547	547
Series C Preferred Unitholders	439	—
Series D Preferred Unitholders	436	—
Common Unitholders	25,628	26,531
General Partner	340	244
Accumulated other comprehensive income	8	3
Total partners’ capital	28,342	28,269
Noncontrolling interest	6,334	5,882
Total equity	34,676	34,151
Total liabilities and equity	$ 79,156	$ 77,965

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017*	2018	2017*
REVENUES:				
Natural gas sales	$1,026	$1,098	$3,112	$3,132
NGL sales	2,695	1,750	6,866	4,782
Crude sales	3,841	2,381	11,336	7,268
Gathering, transportation and other fees	1,579	1,027	4,440	3,118
Refined product sales	382	334	1,234	1,109
Other	118	383	343	1,035
Total revenues	9,641	6,973	27,331	20,444
COSTS AND EXPENSES:				
Cost of products sold	6,745	4,922	19,873	14,595
Operating expenses	632	571	1,863	1,603
Depreciation, depletion and amortization	636	596	1,827	1,713
Selling, general and administrative	123	105	347	335
Total costs and expenses	8,136	6,194	23,910	18,246
OPERATING INCOME	1,505	779	3,421	2,198
OTHER INCOME (EXPENSE):				
Interest expense, net	(387)	(352)	(1,091)	(1,020)
Equity in earnings of unconsolidated affiliates	113	127	147	139
Gain on Sunoco LP common unit repurchase	—	—	172	—
Loss on deconsolidation of CDM	—	—	(86)	—
Gains (losses) on interest rate derivatives	45	(8)	117	(28)
Other, net	21	57	127	137
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	1,297	603	2,807	1,426
Income tax expense (benefit)	(61)	(112)	(32)	22
NET INCOME	1,358	715	2,839	1,404
Less: Net income attributable to noncontrolling interest	223	110	557	266
NET INCOME ATTRIBUTABLE TO PARTNERS	$1,135	$605	$2,282	$1,138

* As adjusted. See Note 1.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017*	2018	2017*
Net income	$1,358	$ 715	$2,839	$1,404
Other comprehensive income (loss), net of tax:				
Change in value of available-for-sale securities	2	2	—	5
Actuarial gain (loss) relating to pension and other postretirement benefit plans	—	5	(2)	2
Change in other comprehensive income from unconsolidated affiliates	2	—	9	(1)
	4	7	7	6
Comprehensive income	1,362	722	2,846	1,410
Less: Comprehensive income attributable to noncontrolling interest	223	110	557	266
Comprehensive income attributable to partners	$1,139	$ 612	$2,289	$1,144

* As adjusted. See Note 1.

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

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ENERGY TRANSFER OPERATING, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2018
(Dollars in millions)
(unaudited)

	Limited Partners								
	Series A Preferred Units	Series B Preferred Units	Series C Preferred Units	Series D Preferred Units	Common Units	General Partner	AOCI	Noncontrolling Interest	Total
Balance, December 31, 2017	$944	$ 547	$ —	$ —	$26,531	$244	$ 3	$ 5,882	$34,151
Distributions to partners	(44)	(27)	(10)	—	(1,975)	(1,080)	—	—	(3,136)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(536)	(536)
Units issued for cash	—	—	436	431	58	—	—	—	925
Capital contributions from noncontrolling interest	—	—	—	—	—	—	—	438	438
Repurchases of common units	—	—	—	—	(24)	—	—	—	(24)
Other comprehensive income, net of tax	—	—	—	—	—	—	7	—	7
Other, net	(1)	—	(1)	(1)	41	(17)	(2)	(7)	12
Net income	45	27	14	6	997	1,193	—	557	2,839
Balance, September 30, 2018	$944	$ 547	$ 439	$ 436	$25,628	$340	$ 8	$ 6,334	$34,676

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

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

	Nine Months Ended September 30,	
	2018	2017*
OPERATING ACTIVITIES		
Net income	$2,839	$1,404
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,827	1,713
Deferred income taxes	(17)	(1)
Non-cash compensation expense	61	57
Gain on Sunoco LP common unit repurchase	(172)	—
Loss on deconsolidation of CDM	86	—
Distributions on unvested awards	(24)	(21)
Equity in earnings of unconsolidated affiliates	(147)	(139)
Distributions from unconsolidated affiliates	328	319
Other non-cash	(132)	(163)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	451	168
Net cash provided by operating activities	5,100	3,337
INVESTING ACTIVITIES		
Cash proceeds from CDM contribution	1,227	—
Cash proceeds from Sunoco LP common unit repurchase	540	—
Cash proceeds from Bakken pipeline transaction	—	2,000
Cash paid for acquisition of PennTex noncontrolling interest	—	(280)
Cash paid for all other acquisitions	(29)	(264)
Capital expenditures, excluding allowance for equity funds used during construction	(4,962)	(6,074)
Contributions in aid of construction costs	95	18
Contributions to unconsolidated affiliates	(13)	(230)
Distributions from unconsolidated affiliates in excess of cumulative earnings	62	116
Proceeds from the sale of assets	13	33
Other	—	(6)
Net cash used in investing activities	(3,067)	(4,687)
FINANCING ACTIVITIES		
Proceeds from borrowings	16,930	19,978
Repayments of debt	(16,520)	(18,487)
Cash paid to affiliate notes	—	(255)
Common units issued for cash	58	2,162
Preferred units issued for cash	867	—
Capital contributions from noncontrolling interest	438	919
Distributions to partners	(3,136)	(2,543)
Distributions to noncontrolling interest	(536)	(306)
Repurchases of common units	(24)	—
Redemption of Legacy ETP Preferred Units	—	(53)
Debt issuance costs	(42)	(50)
Other	5	4
Net cash (used in) provided by financing activities	(1,960)	1,369

Increase in cash and cash equivalents	73	19
Cash and cash equivalents, beginning of period	306	360
Cash and cash equivalents, end of period	$379	$379

* As adjusted. See Note 1.

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

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

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Energy Transfer Operating, L.P. is a consolidated subsidiary of Energy Transfer LP. In October 2018, Energy Transfer Equity, L.P. ("ETE") and Energy Transfer Partners, L.P. ("ETP") completed the merger of ETP with a wholly-owned subsidiary of ETE in a unit-for-unit exchange (the "ETE-ETP Merger"). In connection with the transaction, ETP unitholders (other than ETE and its subsidiaries) received 1.28 common units of ETE for each common unit of ETP they owned.

Immediately prior to the closing of the ETE-ETP Merger, the following also occurred:

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

Following the closing of the ETE-ETP Merger, ETE changed its name to "Energy Transfer LP" and its common units began trading on the New York Stock Exchange under the "ET" ticker symbol on Friday, October 19, 2018. In addition, ETP changed its name to "Energy Transfer Operating, L.P." For purposes of maintaining clarity, the following references are used herein:

- References to "ETP" refer to the entity named Energy Transfer Partners, L.P. prior to the close of the ETE-ETP Merger and Energy Transfer Operating, L.P. subsequent to the close of the ETE-ETP Merger; and
- References to "ETE" refer to the entity named Energy Transfer Equity, L.P. prior to the close of the ETE-ETP Merger and Energy Transfer LP subsequent to the close of the ETE-ETP Merger.

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

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 Sunoco Logistics Merger and related name changes).

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, Colorado and Ohio.
- Energy Transfer Interstate Holdings, LLC, ("ETIH") with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales, which 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 Fayetteville Express Pipeline, LLC, which directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger Pipeline, LLC, engaged in interstate transportation of natural gas.

- CrossCountry Energy, LLC, which indirectly owns a 50% interest in Citrus, which owns 100% of the FGT interstate natural gas pipeline.

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- ETC Midcontinent Express Pipeline, L.L.C., which directly owns a 50% interest in MEP.
- ET Rover Pipeline, LLC, which ETIH directly owns a 50.1% interest in, which owns a 65% interest in the Rover pipeline.
- ETC Compression, LLC, engaged in natural gas compression services and related equipment sales. As discussed further in Note 2 below, in April 2018, we contributed certain assets to USAC.
- 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.'s assets primarily consist of its ownership in Retail Holdings, which owns noncontrolling interests in Sunoco LP and PES. ETP Holdco also holds an equity method investment in ETP through its ownership of ETP Class E, Class G, and Class K units, which investment is eliminated in ETP's 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.

Our consolidated 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, 2017, included in the Partnership's Annual Report on Form 10-K filed with the SEC on February 23, 2018. 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.

The historical common 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.

Change in Accounting Policy

Inventory Accounting Change

During the fourth quarter of 2017, the Partnership elected to change its method of inventory costing to weighted-average cost for certain inventory that had previously been accounted for using the last-in, first-out ("LIFO") method. The inventory impacted by this change included the crude oil, refined products and NGLs associated with the legacy Sunoco Logistics business. Management believes that the weighted-average cost method is preferable to the LIFO method as it more closely aligns the accounting policies across the consolidated entity.

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As a result of this change in accounting policy, the consolidated statement of operations and comprehensive income in prior periods have been retrospectively adjusted, as follows:

	Three Months Ended September 30, 2017			Nine Months Ended September 30, 2017		
	As Originally Reported	Effect of Change	As Adjusted	As Originally Reported	Effect of Change	As Adjusted
Cost of products sold	$4,876	$ 46	$ 4,922	$14,582	$ 13	$ 14,595
Operating income	825	(46)	779	2,211	(13)	2,198
Income before income tax expense (benefit)	649	(46)	603	1,439	(13)	1,426
Net income	761	(46)	715	1,417	(13)	1,404
Net income attributable to partners	651	(46)	605	1,174	(36)	1,138
Comprehensive income	768	(46)	722	1,423	(13)	1,410
Comprehensive income attributable to partners	658	(46)	612	1,180	(36)	1,144

As a result of this change in accounting policy, the consolidated statement of cash flows in prior periods have been retrospectively adjusted, as follows:

	Nine Months Ended September 30, 2017		
	As Originally Reported	Effect of Change	As Adjusted
Net income	$1,417	$ (13)	$ 1,404
Inventory valuation adjustments	(30)	30	—
Net change in operating assets and liabilities, net of effects from acquisitions (change in inventories)	185	(17)	168

Revenue Recognition Standard

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU 2014-09”), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The Partnership adopted ASU 2014-09 on January 1, 2018.

Upon the adoption of ASU 2014-09, the amount of revenue that the Partnership recognizes on certain contracts has changed, primarily due to decreases in revenue (with offsetting decreases to cost of sales) resulting from recognition of non-cash consideration as revenue when received and as cost of sales when sold to third parties. In addition, income statement reclassifications were required for fuel usage and loss allowances related to multiple segments as well as contracts deemed to be in-substance supply agreements in our midstream segment. In addition to the evaluation performed, we have made appropriate design and implementation updates to our business processes, systems and internal controls to support recognition and disclosure under the new standard.

Utilizing the practical expedients allowed under the modified retrospective adoption method, Accounting Standards Codification (“ASC”) Topic 606 was only applied to existing contracts for which the Partnership has remaining performance obligations as of January 1, 2018, and new contracts entered into after January 1, 2018. ASC Topic 606 was not applied to contracts that were completed prior to January 1, 2018.

The Partnership has elected to apply the modified retrospective method to adopt the new standard. For contracts in scope of the new revenue standard as of January 1, 2018, the cumulative effect adjustment to partners’ capital was not material. The comparative information has not been restated under the modified retrospective method and continues to be reported under the accounting standards in effect for those periods.

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The adoption of the new revenue standard resulted in reclassifications between revenue, cost of sales and operating expenses. There were no material changes in the timing of recognition of revenue and therefore no material impacts to the balance sheet upon adoption.

The disclosure below shows the impact of adopting the new standard during the period of adoption compared to amounts that would have been reported under the Partnership's previous revenue recognition policies:

	Three Months Ended September 30, 2018			Nine Months Ended September 30, 2018		
	As Reported	Balances Without Adoption of ASC 606	Effect of Change: Higher/(Lower)	As Reported	Balances Without Adoption of ASC 606	Effect of Change: Higher/(Lower)
Revenues:						
Natural gas sales	$1,026	$ 1,026	$ —	$3,112	$ 3,112	$ —
NGL sales	2,695	2,686	9	6,866	6,839	27
Crude sales	3,841	3,838	3	11,336	11,326	10
Gathering, transportation and other fees	1,579	1,783	(204)	4,440	4,977	(537)
Refined product sales	382	381	1	1,234	1,233	1
Other	118	118	—	343	343	—
Costs and expenses:						
Cost of products sold	$6,745	$ 6,949	$ (204)	$19,873	$ 20,410	$ (537)
Operating expenses	632	619	13	1,863	1,825	38

Additional disclosures related to revenue are included in Note 11.

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 2016-02

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which establishes the principles that lessees and lessors shall apply to report information about the amount, timing, and uncertainty of cash flows arising from a lease. The update requires lessees to record virtually all leases on their balance sheets. For lessors, this amended guidance modifies the classification criteria and the accounting for sales-type and direct financing leases. In January 2018, the FASB issued Accounting Standards Update No. 2018-01 ("ASU 2018-01"), which provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the existing lease guidance in Topic 840. The Partnership plans to elect the package of transition practical expedients and will adopt this standard beginning with its first quarter of fiscal 2019 and apply it retrospectively at the beginning of the period of adoption through a cumulative-effect adjustment to retained earnings. The Partnership has performed several procedures to evaluate the impact of the adoption of this standard on the financial statements and disclosures and address the implications of Topic 842 on future lease arrangements. The procedures include reviewing all forms of leases, performing a completeness assessment over the lease population, establishing processes and controls to timely identify new and modified lease agreements, educating its employees on these new processes and controls and implementing a third-party supported lease accounting information system to account for our leases in accordance with the new standard. However, we are still in the process of quantifying this impact. We expect that upon adoption most of the Partnership's lease commitments will be recognized as right of use assets and lease obligations.

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ASU 2017-12

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

ASU 2018-02

In February 2018, the FASB issued Accounting Standards Update No. 2018-02, Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, which allows a reclassification from accumulated other comprehensive income to partners' capital for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. The Partnership elected to early adopt this ASU in the first quarter of 2018. The effect of the adoption was not material.

2. ACQUISITIONS AND OTHER INVESTING TRANSACTIONS

ETE Contribution of Assets to ETP

Immediately prior to the closing of the ETE-ETP Merger discussed in Note 1, ETE contributed the following to ETP:

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

ETP, Sunoco LP, USAC and Lake Charles LNG and Other are under common control of ETE; therefore, we expect to account for the contribution transactions at historical cost as a reorganization of entities under common control. Accordingly, beginning with the quarter ending December 31, 2018, ETP's consolidated financial statements will be retrospectively adjusted to reflect consolidation of Sunoco LP and Lake Charles LNG and Other for all prior periods and consolidation of USAC subsequent to April 2, 2018 (the date ETE acquired USAC's general partner).

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The following table summarizes the assets and liabilities of Sunoco LP, USAC and Lake Charles LNG and Other as of September 30, 2018, which amounts will be retrospectively consolidated in ETP's consolidated balance sheets beginning with the quarter ending December 31, 2018, subject to the elimination of intercompany balances:

	Sunoco LP	USAC	Lake Charles LNG and Other
Current assets	$1,331	$230	$28
Property, plant and equipment, net	1,494	2,541	746
Goodwill	1,534	619	184
Intangible assets	655	399	35
Other non-current assets	134	25	909
Total assets	$5,148	$3,814	$1,902
Current liabilities	$1,086	$173	$107
Long-term debt, less current maturities	2,774	1,731	—
Other non-current liabilities	343	6	8
Preferred Units	—	477	—
Net assets	$945	$1,427	$1,787

The unaudited financial information in the table below summarizes the combined results of our operations and those of Sunoco LP, USAC and Lake Charles LNG and Other on a pro forma basis, to reflect the retrospective consolidation of those entities. The pro forma financial information is presented for informational purposes only and is not indicative of the results of operations that would have been achieved. The pro forma adjustments include the effect of intercompany revenue eliminations:

	Unaudited Pro Forma Nine Months Ended September 30,	
	2018	2017
Revenues	$40,514	$29,072
Net income attributable to partners	$2,282	$1,138

CDM Contribution

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

Prior to the CDM Contribution, the CDM entities were indirect wholly-owned subsidiaries of ETP. Beginning April 2018, ETP's consolidated financial statements reflected an equity method investment in USAC. CDM's assets and liabilities were not reflected as held for sale, nor were CDM's results reflected as discontinued operations in these financial statements. At September 30, 2018, the carrying value of ETP's investment in USAC was $385 million, which is reflected in the all other segment. ETP recorded an $86 million loss on the deconsolidation of CDM including a $45 million accrual related to the indemnification of USAC related to an ongoing CDM sales and use tax

audit.
In connection with the CDM Contribution, ETE acquired (i) all of the outstanding limited liability company interests in USA Compression GP, LLC, the general partner of USAC, and (ii) 12,466,912 USAC common units for cash consideration equal to $250 million.

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3. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES

HPC

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

Sunoco LP

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

As of September 30, 2018, ETP owned 26.2 million Sunoco LP common units representing 31.8% of Sunoco LP's total outstanding common units. Our investment in Sunoco LP is reflected in the all other segment. As of September 30, 2018, the carrying value of our investment in Sunoco LP was $542 million.

Subsequent to the ETE-ETP Merger, ETP owns 28.5 million Sunoco LP common units. For the periods presented herein, ETP's investment in Sunoco LP is reflected under the equity method of accounting; however, for periods subsequent to the ETE-ETP Merger, ETP will reflect Sunoco LP as a consolidated subsidiary.

USAC

As of September 30, 2018, ETP owned 19.2 million USAC common units and 6.4 million USAC Class B Units, together representing 26.6% of the limited partner interests in USAC. USAC provides compression services to producers, processors, gatherers and transporters of natural gas and crude oil. Our investment in USAC is reflected in the all other segment. As of September 30, 2018, the carrying value of our investment in USAC was $385 million.

Subsequent to the ETE-ETP Merger, ETP owns 39.7 million USAC common units and 6.4 million USAC Class B Units. For the periods presented herein, ETP's investment in USAC is reflected under the equity method of accounting; however, for periods subsequent to the ETE-ETP Merger, ETP will reflect USAC as a consolidated subsidiary.

4. 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.

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

	Nine Months Ended September 30, 2018	2017*
Accounts receivable	$251	$(77)
Accounts receivable from related companies	206	46
Inventories	48	133
Other current assets	(23)	37
Other non-current assets, net	(99)	(89)
Accounts payable	(177)	96
Accounts payable to related companies	(199)	(11)
Accrued and other current liabilities	351	(26)
Other non-current liabilities	21	57
Derivative assets and liabilities, net	72	2
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$451	$168

* As adjusted. See Note 1.

Non-cash investing and financing activities are as follows:

	Nine Months Ended September 30, 2018	2017
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$1,026	$1,236
USAC limited partner interests received in the CDM Contribution (see Note 2)	411	—
NON-CASH FINANCING ACTIVITIES:		
Contribution of property, plant and equipment from noncontrolling interest	$—	$988

5. INVENTORIES

Inventories consisted of the following:

	September 30, 2018	December 31, 2017
Natural gas, NGLs and refined products	$ 615	$ 733
Crude oil	643	551
Spare parts and other	249	305
Total inventories	$ 1,507	$ 1,589

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.

6. 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, 2018 was $34.39 billion and $33.85 billion, respectively. As of December 31, 2017, the aggregate fair value and carrying amount of

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our consolidated debt obligations was $34.28 billion and $33.09 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, 2018, no transfers were made between any levels within the fair value hierarchy.

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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, 2018 and December 31, 2017 based on inputs used to derive their fair values:

		Fair Value Measurements at September 30, 2018	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$48	$ 48	$ —
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	25	25	—
Forward Physical Contracts	12	—	12
Power:			
Forwards	36	—	36
Options – Puts	1	1	—
NGLs – Forwards/Swaps	476	476	—
Total commodity derivatives	599	550	49
Other non-current assets	28	18	10
Total assets	$627	$ 568	$ 59
Liabilities:			
Interest rate derivatives	$(97)	$ —	$ (97)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(89)	(89)	—
Swing Swaps IFERC	(1)	—	(1)
Fixed Swaps/Futures	(26)	(26)	—
Forward Physical Contracts	(7)	—	(7)
Power:			
Forwards	(30)	—	(30)
Futures	(1)	(1)	—
NGLs – Forwards/Swaps	(521)	(521)	—
Refined Products – Futures	(5)	(5)	—
Crude – Forwards/Swaps	(190)	(190)	—
Total commodity derivatives	(870)	(832)	(38)
Total liabilities	$(967)	$ (832)	$ (135)

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	Fair Value Total	Fair Value Measurements at December 31, 2017 Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 11	$ 11	$ —
Swing Swaps IFERC	13	—	13
Fixed Swaps/Futures	70	70	—
Forward Physical Contracts	8	—	8
Power – Forwards	23	—	23
NGLs – Forwards/Swaps	191	191	—
Crude:			
Forwards/Swaps	2	2	—
Futures	2	2	—
Total commodity derivatives	320	276	44
Other non-current assets	21	14	7
Total assets	$ 341	$ 290	$ 51
Liabilities:			
Interest rate derivatives	$ (219)	$ —	$ (219)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(24)	(24)	—
Swing Swaps IFERC	(15)	(1)	(14)
Fixed Swaps/Futures	(57)	(57)	—
Forward Physical Contracts	(2)	—	(2)
Power – Forwards	(22)	—	(22)
NGLs – Forwards/Swaps	(186)	(186)	—
Refined Products – Futures	(25)	(25)	—
Crude:			
Forwards/Swaps	(6)	(6)	—
Futures	(1)	(1)	—
Total commodity derivatives	(338)	(300)	(38)
Total liabilities	$ (557)	$ (300)	$ (257)

7. DEBT OBLIGATIONS

ETP Senior Notes Offering and Redemption

In June 2018, ETP issued the following senior notes:

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

The senior notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the senior notes. The principal on the senior notes is payable upon maturity and interest is paid semi-annually.

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The senior notes rank equally in right of payment with ETP's existing and future senior debt, and senior in right of payment to any future subordinated debt ETP may incur. The notes of each series will initially be fully and unconditionally guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis so long as it guarantees any of our other long-term debt. The guarantee for each series of notes ranks equally in right of payment with all of the existing and future senior debt of Sunoco Logistics Partners Operations L.P., including its senior notes.

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

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

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

Credit Facilities and Commercial Paper

ETP Five-Year Credit Facility

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

As of September 30, 2018, the ETP Five-Year Credit Facility had $1.78 billion outstanding, of which $1.57 billion was commercial paper. The amount available for future borrowings was $2.06 billion after taking into account letters of credit of $163 million, but before taking into account the additional capacity from the October 19, 2018 amendment. The weighted average interest rate on the total amount outstanding as of September 30, 2018 was 3.00%.

ETP 364-Day Facility

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

Bakken Credit Facility

In August 2016, ETP and Phillips 66 completed project-level financing of the Bakken pipeline. The $2.50 billion credit facility matures in August 2019 (the "Bakken Credit Facility"). As of September 30, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings, all of which has been reflected in current maturities of long-term debt on the Partnership's consolidated balance sheet. The weighted average interest rate on the total amount outstanding as of September 30, 2018 was 3.85%.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of September 30, 2018.

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8. EQUITY

The changes in outstanding common units during the nine months ended September 30, 2018 were as follows:

	Number of Units
Number of common units at December 31, 2017	1,164.1
Common units issued in connection with the distribution reinvestment plan	2.9
Common units issued in connection with certain transactions	1.3
Issuance of common units under equity incentive plans	0.1
Repurchases of common units in open-market transactions	(1.2)
Number of common units at September 30, 2018	1,167.2

Subsequent to the ETE-ETP Merger in October 2018, all of the outstanding ETP common units are held directly or indirectly by ETE, including the ETP common units issued in connection with the conversion of the general partner interest to a non-economic interest and the cancellation of the IDRs, as discussed in Note 1, and the contributions of the investments in ETE's other subsidiaries, as discussed in Note 2. In addition, the ETP Class I units and Class J units were also cancelled in connection with the ETE-ETP Merger.

Equity Distribution Program

During the nine months ended September 30, 2018, there were no units issued under the Partnership's equity distribution agreement. In connection with the ETE-ETP Merger, the equity distribution program was terminated in October 2018.

Distribution Reinvestment Program

During the nine months ended September 30, 2018, distributions of $57 million were reinvested under the Partnership's distribution reinvestment plan. In connection with the ETE-ETP Merger, the distribution reinvestment program was terminated in October 2018.

Preferred Units

ETP issued 950,000 Series A Preferred Units and 550,000 Series B Preferred Units in November 2017 and has issued additional preferred units in 2018, as discussed below. Subsequent to the ETE-ETP Merger, all of ETP's Series A, Series B, Series C and Series D Preferred Units remain outstanding.

Series C Preferred Units Issuance

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

Distributions on the Series C Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2023, at a rate of 7.375% per annum of the stated liquidation preference of $25. On and after May 15, 2023, distributions on the Series C Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.530% per annum. The Series C Preferred Units are redeemable at ETP's option on or after May 15, 2023 at a redemption price of $25 per Series C Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Series D Preferred Units Issuance

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

Distributions on the Series D Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, August 15, 2023, at a rate of 7.625% per annum of the stated liquidation preference of $25. On and after August 15, 2023, distributions on the Series D Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.378% per annum. The Series D Preferred Units are redeemable at ETP's option on or after August 15, 2023 at a redemption price of $25 per Series D

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Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Cash Distributions

Distributions on common units declared and paid by the Partnership subsequent to December 31, 2017 but prior to the closing of the ETE-ETP Merger as discussed in Note 1 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017	February 8, 2018	February 14, 2018	$0.5650
March 31, 2018	May 7, 2018	May 15, 2018	0.5650
June 30, 2018	August 6, 2018	August 14, 2018	0.5650

Distributions on ETP's preferred units declared and/or paid by the Partnership subsequent to December 31, 2017 were as follows:

Period Ended	Record Date	Payment Date	Rate
Series A Preferred Units			
December 31, 2017	February 1, 2018	February 15, 2018	$15.451
June 30, 2018	August 1, 2018	August 15, 2018	31.250
Series B Preferred Units			
December 31, 2017	February 1, 2018	February 15, 2018	$16.378
June 30, 2018	August 1, 2018	August 15, 2018	33.125
Series C Preferred Units			
June 30, 2018	August 1, 2018	August 15, 2018	$0.5634
September 30, 2018	November 1, 2018	November 15, 2018	0.4609
Series D Preferred Units			
September 30, 2018	November 1, 2018	November 15, 2018	$0.5931

Accumulated Other Comprehensive Income

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

	September 30, 2018	December 31, 2017
Available-for-sale securities [1]	$ 6	$ 8
Foreign currency translation adjustment	(5)	(5)
Actuarial loss related to pensions and other postretirement benefits	(7)	(5)
Investments in unconsolidated affiliates, net	14	5
Total AOCI, net of tax	$ 8	$ 3

(1) Effective January 1, 2018, the Partnership adopted Accounting Standards Update No. 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities, which resulted in the reclassification of $2 million from accumulated other comprehensive income related to available-for-sale securities to common unitholders.

9. INCOME TAXES

The Partnership's effective tax rate differs from the statutory rate primarily due to partnership earnings that are not subject to United States federal and most state income taxes at the partnership level. For the three and nine months ended September 30, 2018, the Partnership's income tax benefit also reflected $109 million and $179 million, respectively, of deferred benefit adjustments as the result of a state statutory rate reduction.

Sunoco, Inc. historically included certain government incentive payments as taxable income on its federal and state income tax returns. In connection with Sunoco, Inc.'s 2004 through 2011 years, Sunoco, Inc. filed amended returns with the Internal

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Revenue Service ("IRS") excluding these government incentive payments from federal taxable income. The IRS denied the amended returns and Sunoco, Inc. petitioned the Court of Federal Claims ("CFC") on this issue. In November 2016, the CFC ruled against Sunoco, Inc., and the Federal Circuit affirmed the CFC's ruling on November 1, 2018. Sunoco, Inc. is considering seeking further review of this decision. Due to the uncertainty surrounding the litigation, a reserve of $530 million was previously established for the full amount of the pending refund claims.

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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 certain of Sunoco LP's senior notes and $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 ("ETC M-A").

On January 23, 2018, Sunoco LP redeemed the previously guaranteed senior notes, repaid and terminated the term loan and issued the following notes (the "Sunoco LP Notes") for which ETC M-A has also guaranteed collection with respect to the payment of principal amounts:

- $1.00 billion aggregate principal amount of 4.875% senior notes due 2023;
- $800 million aggregate principal amount of 5.50% senior notes due 2026; and
- $400 million aggregate principal amount of 5.875% senior notes due 2028.

Under the guarantee of collection, ETC M-A would have the obligation to pay the principal of each series of notes once all remedies, including in the context of bankruptcy proceedings, have first been fully exhausted against Sunoco LP with respect to such payment obligation, and holders of the notes are still owed amounts in respect of the principal of such notes. ETC M-A will not otherwise be subject to the covenants of the indenture governing the notes.

In connection with the issuance of the Sunoco LP Notes, Sunoco LP entered into a registration rights agreement with the initial purchasers pursuant to which Sunoco LP agreed to complete an offer to exchange the Sunoco LP Notes for an issue of registered notes with terms substantively identical to each series of Sunoco LP Notes and evidencing the same indebtedness as the Sunoco LP Notes on or before January 23, 2019.

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 FERC approved an audit report in October 2018. In response to the findings in the audit report, the Company expects to make certain changes to its processes, policies and procedures; however, the Company does not expect the findings to result in any changes to its financial statements.

Commitments

In the normal course of business, ETP purchases, processes and sells natural gas pursuant to long-term contracts and enters into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. ETP believes that the terms of these agreements are commercially reasonable and will not have a material adverse effect on its financial position or results of operations.

Our joint venture agreements require that we 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.

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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,	
	2018	2017	2018	2017
Rental expense	$ 21	$ 29	$ 60	$ 68

Litigation and Contingencies

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

Dakota Access Pipeline

On July 25, 2016, the United States Army Corps of Engineers (“USACE”) issued permits to Dakota Access, LLC (“Dakota Access”) to make two crossings of the Missouri River in North Dakota. The USACE also issued easements to allow the pipeline to cross land owned by the USACE adjacent to the Missouri River. On July 27, 2016, the Standing Rock Sioux Tribe (“SRST”) filed a lawsuit in the United States District Court for the District of Columbia (“the Court”) against the USACE and challenged the legality of these permits and claimed violations of the National Historic Preservation Act (“NHPA”). The SRST also sought a preliminary injunction to rescind the USACE permits while the case was pending, which the court denied on September 9, 2016. Dakota Access intervened in the case. The Cheyenne River Sioux Tribe (“CRST”) also intervened. The SRST filed an amended complaint and added claims based on treaties between the SRST and the CRST and the United States and statutes governing the use of government property.

In February 2017, in response to a presidential memorandum, the Department of the Army delivered an easement to Dakota Access allowing the pipeline to cross Lake Oahe. The CRST moved for a preliminary injunction and temporary restraining order (“TRO”) to block operation of the pipeline, which was denied, and raised claims based on the religious rights of the CRST.

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

On June 14, 2017, the Court ruled on SRST’s and CRST’s motions for partial summary judgment and the USACE’s cross-motions for partial summary judgment. The Court concluded that the USACE had not violated trust duties owed to the Tribes and had generally complied with its obligations under the Clean Water Act, the Rivers and Harbors Act, the Mineral Leasing Act, the National Environmental Policy Act (“NEPA”) and other related statutes; however, the Court remanded to the USACE three discrete issues for further analysis and explanation of its prior determinations under certain of these statutes. On May 3, 2018, the District Court ordered the USACE to file a status report by June 8, 2018 informing the Court when the USACE expects the remand process to be complete. On June 8, 2018, the USACE filed a status report stating that they will conclude the remand process by August 10, 2018. On August 7, 2018, the USACE informed the Court that they will need until August 31, 2018 to finish the remand process. On

August 31, 2018, the USACE informed the Court that it had completed the remand process and that it had determined that the three issues remanded by the Court had been correctly decided. The USACE indicated that a document detailing its remand analysis would be filed after a “confidentiality review.” Following the submission by USACE of its detailed remand analysis, it is expected that the Court will make a determination regarding the three discrete issues covered by the remand order.

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On December 4, 2017, the Court imposed three conditions on continued operation of the pipeline during the remand process. First, Dakota Access must retain an independent third-party to review its compliance with the conditions and regulations governing its easements and to assess integrity threats to the pipeline. The assessment report was filed with the Court. Second, the Court has directed Dakota Access to continue its work with the Tribes and the USACE to revise and finalize its emergency spill response planning for the section of the pipeline crossing Lake Oahe. Dakota Access filed the revised plan with the Court. And third, the Court has directed Dakota Access to submit bi-monthly reports during the remand period disclosing certain inspection and maintenance information related to the segment of the pipeline running between the valves on either side of the Lake Oahe crossing. The first and second reports were filed with the court on December 29, 2017 and February 28, 2018, respectfully.

In November 2017, the Yankton Sioux Tribe (“YST”), moved for partial summary judgment asserting claims similar to those already litigated and decided by the Court in its June 14, 2017 decision on similar motions by CRST and SRST. YST argues that the USACE and Fish and Wildlife Service violated NEPA, the Mineral Leasing Act, the Rivers and Harbors Act, and YST’s treaty and trust rights when the government granted the permits and easements necessary for the pipeline.

On March 19, 2018, the District Court denied YST’s motion for partial summary judgment and instead granted judgment in favor of Dakota Access pipeline and the USACE on the claims raised in YST’s motion. The Court concluded that YST’s NHPA claims are moot because construction of the pipeline is complete and that the government’s review process did not violate NEPA or the various treaties cited by the YST.

On February 8, 2018, the Court docketed a motion by CRST to “compel meaningful consultation on remand.” SRST then made a similar motion for “clarification re remand process and remand conditions.” The motions seek an order from the Court directing the USACE as to how it should conduct its additional review on remand. Dakota Access pipeline and the USACE opposed both motions. On April 16, 2018, the Court denied both motions.

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

Mont Belvieu Incident

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

MTBE Litigation

Sunoco, Inc. and/or Sunoco, Inc. (R&M) (now known as Sunoco (R&M), LLC) are defendants in lawsuits alleging MTBE contamination of groundwater. The plaintiffs, state-level governmental entities, assert product liability, nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices claims. The plaintiffs seek to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages, and attorneys’ fees.

As of September 30, 2018, Sunoco, Inc. is a defendant in six cases, including one case each initiated by the States of Maryland, Vermont and Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants Energy Transfer Partners, L.P., ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals, L.P.

In late July 2018, the Court in the Vermont matter denied Plaintiff’s motion to amend its complaint to add specific allegations regarding some of the sites the court previously dismissed. In early September 2018, Sunoco, Inc. participated in a defense group effort to resolve the case without further litigation. A settlement in principle to resolve the remaining statewide Vermont Case was reached in September 2018.

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

Regency Merger Litigation

Purported Regency unitholders filed lawsuits in state and federal courts in Dallas and Delaware asserting claims relating to the Regency-ETP merger (the "Regency Merger"). All but one Regency Merger-related lawsuits have been dismissed. On June 10, 2015, Adrian Dieckman ("Dieckman"), a purported Regency unitholder, filed a class action complaint in the Court of Chancery of the State of Delaware (the "Regency Merger Litigation"), on behalf of Regency's common unitholders against Regency GP, LP; Regency GP LLC; ETE, ETP, ETP GP, and the members of Regency's board of directors ("Defendants").

The Regency Merger Litigation alleges that the Regency Merger breached the Regency partnership agreement because Regency's conflicts committee was not properly formed, and the Regency Merger was not approved in good faith. On March 29, 2016, the Delaware Court of Chancery granted Defendants' motion to dismiss the lawsuit in its entirety. Dieckman appealed. On January 20, 2017, the Delaware Supreme Court reversed the judgment of the Court of Chancery. On May 5, 2017, Plaintiff filed an Amended Verified Class Action Complaint. Defendants then filed Motions to Dismiss the Amended Complaint and a Motion to Stay Discovery on May 19, 2017. On February 20, 2018, the Court of Chancery issued an Order granting in part and denying in part the motions to dismiss, dismissing the claims against all defendants other than Regency GP, LP and Regency GP LLC (the "Regency Defendants"). On March 6, 2018, the Regency Defendants filed their Answer to Plaintiff's Verified Amended Class Action Complaint. Trial is currently set for September 23-27, 2019.

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

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 $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. On June 8, 2018, the Texas Supreme Court ordered briefing on the merits. ETP's petition for review remains under consideration by the Texas Supreme Court.

ETE-ETP Merger Litigation

On September 17, 2018, William D. Warner ("Plaintiff"), a purported ETP unitholder, filed a putative class action asserting violations of various provisions of the Securities Exchange Act of 1934 and various rules promulgated thereunder in connection with the ETE-ETP Merger against ETP, Kelcy L. Warren, Michael K. Grimm, Marshall S. McCrea, Matthew S. Ramsey, David K. Skidmore, and W. Brett Smith ("Defendants"). Plaintiff specifically alleges that the Form S-4 Registration Statement issued in connection with the ETE-ETP Merger omits and/or misrepresents material information. Defendants believe the allegations have no merit and intend to defend vigorously against them. On October 26, 2018, Plaintiff and Defendants entered into a stipulation staying Defendants' response deadlines until the designation of a lead plaintiff/lead counsel structure in accordance with the Private Securities Litigation Reform Act.

Bayou Bridge

On January 11, 2018, environmental groups and a trade association filed suit against the USACE in the United States District Court for the Middle District of Louisiana. Plaintiffs allege that the USACE's issuance of permits authorizing the construction of the Bayou Bridge Pipeline through the Atchafalaya Basin (“Basin”) violated the National Environmental Policy Act, the Clean Water Act, and the Rivers and Harbors Act. They asked the district court to vacate these permits and to enjoin construction of the project through the Basin until the USACE corrects alleged deficiencies in its decision-making process. ETP, through its subsidiary Bayou Bridge Pipeline, LLC (“Bayou Bridge”), intervened on January 26, 2018. On March 27, 2018, Bayou Bridge filed an answer to the complaint.

On January 29, 2018, Plaintiffs filed motions for a preliminary injunction and TRO. United States District Court Judge Shelly Dick denied the TRO on January 30, 2018, but subsequently granted the preliminary injunction on February 23, 2018. On February 26, 2018, Bayou Bridge filed a notice of appeal and a motion to stay the February 23, 2018 preliminary injunction order. On February 27, 2018, Judge Dick issued an opinion that clarified her February 23, 2018 preliminary injunction order and denied Bayou Bridge's February 26, 2018 motion to stay as moot. On March 1, 2018, Bayou Bridge filed a new notice of appeal and motion to stay the February 27, 2018 preliminary injunction order in the district court. On March 5, 2018, the district court denied the March 1, 2018 motion to stay the February 27, 2018 order.

On March 2, 2018, Bayou Bridge filed a motion to stay the preliminary injunction in the Fifth Circuit. On March 15, 2018, the Fifth Circuit granted a stay of injunction pending appeal and found that Bayou Bridge "is likely to succeed on the merits of its claim that the district court abused its discretion in granting a preliminary injunction." Oral arguments were heard on the merits of the appeal, that is, whether the district court erred in granting the preliminary injunction in the Fifth Circuit on April 30, 2018. The district court has stayed the merits case pending decision of the Fifth Circuit. On May 10, 2018, the District Court stayed the litigation pending a decision from the Fifth Circuit. On July 6, 2018, the Fifth Circuit vacated the Preliminary Injunction and remanded the case back to the District Court. Construction is ongoing.

On August 14, 2018, Plaintiffs sought leave of court to amend their complaint to add an "as applied" challenge to the USACE's application of the Louisiana Rapid Assessment Method to Bayou Bridge's permits. Defendants' filed motions in opposition on September 11, 2018. On September 11, 2018, Plaintiffs filed a motion for partial summary judgment on the issue of the USACE's analysis of the risks of an oil spill once the pipeline is in operation.

At an October 2, 2018 scheduling conference, the USACE agreed to lodge the administrative record for Plaintiff's original complaint, which it has done. Summary judgment briefing will be concluded by the Spring of 2019.

Rover

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and Pretec Directional Drilling, LLC ("Pretec") seeking to recover approximately $2.6 million in civil penalties allegedly owed and certain injunctive relief related to permit compliance. Laney Directional Drilling Co., Atlas Trenchless, LLC, Mears Group, Inc., D&G Directional Drilling, Inc. d/b/a D&G Directional Drilling, LLC, and B&T Directional Drilling, Inc. (collectively, with Rover and Pretec, "Defendants") were added as defendants on April 17, 2018 and July 18, 2018.

Ohio EPA alleges that the Defendants illegally discharged millions of gallons of drilling fluids into Ohio's waters that caused pollution and degraded water quality, and that the Defendants harmed pristine wetlands in Stark County. Ohio EPA further alleges that the Defendants caused the degradation of Ohio's waters by discharging pollution in the form of sediment-laden storm water into Ohio's waters and that Rover violated its hydrostatic permits by discharging effluent with greater levels of pollutants than those permits allowed and by not properly sampling or monitoring effluent for required parameters or reporting those alleged violations. Rover and other Defendants filed several motions to dismiss and Ohio EPA filed a motion in opposition.

In January 2018, Ohio EPA sent a letter to the FERC to express concern regarding drilling fluids lost down a hole during horizontal directional drilling ("HDD") operations as part of the Rover Pipeline construction. Rover sent a January 24 response to the FERC and stated, among other things, that as Ohio EPA conceded, Rover was conducting its drilling operations in accordance with specified procedures that had been approved by the FERC and reviewed by the Ohio EPA. In addition, although the HDD operations were crossing the same resource as that which led to an inadvertent release of drilling fluids in April 2017, the drill in 2018 had been redesigned since the original crossing. Ohio EPA expressed concern that the drilling fluids could deprive organisms in the wetland of oxygen. Rover, however, has now fully remediated the site, a fact with which Ohio EPA concurs.

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, 2018 and December 31, 2017, accruals of approximately $55 million and $53 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

On April 25, 2018, and as amended on April 30, 2018, State Senator Andrew Dinniman filed a Formal Complaint and Petition for Interim Emergency Relief ("Complaint") against Sunoco Pipeline L.P. ("SPLP") before the Pennsylvania Public Utility Commission ("PUC"). Specifically, the Complaint alleges that (i) the services and facilities provided by the Mariner East Pipeline ("ME1," "ME2" or "ME2x") in West Whiteland Township ("the Township") are unreasonable, unsafe, inadequate, and insufficient for, among other reasons, selecting an improper and unsafe route through densely populated portions of the Township with homes, schools, and infrastructure and causing inadvertent returns and sinkholes during construction because of unstable geology in the Township; (ii) SPLP failed to warn the public of the dangers of the pipeline; (iii) the construction of ME2 and ME2x increases the risk of damage to the existing co-located ME1 pipeline; and (iv) ME1, ME2 and ME2x are not public utility facilities. Based on these allegations, Senator Dinniman's Complaint seeks emergency relief by way of an order (i) prohibiting construction of ME2 and ME2x in the Township; (ii) prohibiting operation of ME1; (iii) in the alternative to (i) and (ii) prohibiting the construction of ME2 and ME2x and the operation of ME1 until SPLP fully assesses and the PUC approves the condition, adequacy, efficiency, safety, and reasonableness of those pipelines and the geology in which they sit; (iv) requiring SPLP to release to the public its written integrity management plan and risk analysis for these pipelines; and (v) finding that these pipelines are not public utility facilities. In short, the relief, if granted, would continue the suspension of operation of ME1 and suspend further construction of ME2 and ME2x in the Township.

Following a hearing on May 7, 2018 and 10, 2018, Administrative Law Judge Elizabeth H. Barnes ("ALJ") issued an Order on May 24, 2018 that granted Senator Dinniman's petition for interim emergency relief and required SPLP to shut down ME1, to discontinue construction of ME2 and ME2x within the Township, and required SPLP to provide various types of information and perform various geotechnical and geophysical studies within the Township. The ALJ's Order was immediately effective, and SPLP complied by shutting down service on ME1 and discontinuing all construction in the Township on ME2 and ME2x. The ALJ's Order was automatically certified as a material question to the PUC, which issued an Opinion and Order on June 15, 2018 (following a public meeting on June 14, 2018) that reversed in part and affirmed in part the ALJ's Order. PUC's Opinion and Order permitted SPLP to resume service on ME1, but continued the shutdown of construction on ME2 and ME2x pending the submission of the following three types of information to PUC: (i) inspection and testing protocols; (ii) comprehensive emergency response plan; and (iii) safety training curriculum for employees and contractors. SPLP submitted the required information on June 22, 2018. On July 2, 2018, Senator Dinniman and intervenors responded to the submission. SPLP is also required to provide an affidavit that the Pennsylvania Department of Environmental Protection ("PADEP") has issued appropriate approvals for construction of ME2 and ME2x in the Township before recommencing construction of ME2 and ME2x locations within the Township. SPLP submitted all necessary affidavits. On August 2, 2018 the PUC entered an Order lifting the stay of construction on ME2 and ME2x in the Township with respect to four of the eight areas within the Township where the necessary environmental permits had been issued. Subsequently, after PADEP's issuance of permit modifications for two of the four remaining construction sites, the PUC lifted the construction stay on those two sites as well.

Also on August 2, 2018, the PUC ratified its prior action by notational voting of certifying for interlocutory appeal to the Pennsylvania Commonwealth Court the legal issue of whether Senator Dinniman has standing to pursue the action. SPLP submitted a petition for permission to appeal on this issue of standing. Senator Dinniman and intervenors opposed that petition. On September 27, 2018, the Commonwealth Court issued an Order that certified for appeal the issue of Senator Dinniman's standing. The Order stays all proceedings in the PUC.

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

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

No amounts have been recorded in our September 30, 2018 or December 31, 2017 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Environmental Matters

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

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

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

In February 2017, we received letters from the DOJ and Louisiana Department of Environmental Quality notifying 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 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 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma operated and owned by SPLP in January 2015. In July 2017, we had a meeting with the DOJ, EPA and Louisiana Department of Environmental Quality (“LDEQ”) during which the agencies presented their initial demand for civil penalties and injunctive relief. Since then, the parties have reached an agreement in principal to resolve all penalties with DOJ and LDEQ along with injunctive relief requirements to be completed within three years all of which is being formalized in a Consent Decree. In addition to resolution of the civil penalty, we continue to discuss national resource damages with the Louisiana trustees.

On January 3, 2018, PADEP issued an Administrative Order to SPLP directing that work on the Mariner East 2 and 2X pipelines be stopped. The Administrative Order detailed alleged violations of the permits issued by PADEP in February 2017, during the construction of the project. SPLP began working with PADEP representatives immediately after the Administrative Order was issued to resolve the compliance issues. Those compliance issues could not be fully resolved by the deadline to appeal the Administrative Order, so SPLP took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, SPLP entered into a Consent Order and Agreement with PADEP that (i) withdraws the Administrative Order; (ii) establishes requirements for compliance with permits on a going forward basis; (iii) resolves the non-compliance alleged in the Administrative

Order; and (iv) conditions restart of work on an agreement by SPLP to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, SPLP admits to the factual allegations, but does not admit to the conclusions of law that were made by PADEP. PADEP also found in the Consent Order and Agreement that SPLP had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. SPLP concurrently filed a request to the Pennsylvania Environmental Hearing Board to discontinue the appeal of the Administrative Order. That request was granted on February 8, 2018.

Environmental Remediation

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

- certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of polychlorinated biphenyls (“PCBs”). PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.
- certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- legacy sites related to Sunoco, Inc. that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.
- Sunoco, Inc. is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of September 30, 2018, Sunoco, Inc. had been named as a PRP at approximately 41 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.’s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

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

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

	September 30, 2018	December 31, 2017
Current	$ 36	$ 36
Non-current	281	314
Total environmental liabilities	$ 317	$ 350

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, 2018 and 2017, the Partnership recorded $17 million and $5 million, respectively, of expenditures related to environmental cleanup programs. During the nine months ended September 30, 2018 and 2017, the Partnership recorded $28 million and $18 million, respectively, of expenditures related to environmental programs.

Our pipeline operations are subject to regulation by the United States Department of Transportation under the Pipeline Hazardous Materials Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

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

11. REVENUE

The following disclosures discuss the Partnership's revised revenue recognition policies upon the adoption of ASU 2014-09 on January 1, 2018, as discussed in Note 1. These policies were applied to the current period only, and the amounts reflected in the Partnership's consolidated financial statements for the three and nine months ended September 30, 2017 were recorded under the Partnership's previous accounting policies.

Disaggregation of revenue

The Partnership's consolidated financial statements reflect the following six reportable segments, which also represent the level at which the Partnership aggregates revenue for disclosure purposes:

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

Note 14 depicts the disaggregation of revenue by segment, with revenue amounts reflected in accordance with ASC Topic 606 for 2018 and ASC Topic 605 for 2017.

Intrastate transportation and storage revenue

Our intrastate transportation and storage segment's revenues are determined primarily by the volume of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines or that is injected or withdrawn into or out of our storage facilities. Firm transportation and storage contracts require customers to pay certain minimum fixed fees regardless of the volume of commodity they transport or store. These contracts typically include a variable incremental charge based on the actual volume of transportation commodity throughput or stored commodity injected/withdrawn. Under interruptible transportation and storage contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of commodity they transport across our pipelines or inject/withdraw into or out of our storage facilities. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or storage) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of service, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer's request. Revenue is recognized for interruptible contracts at the time the services are performed.

Interstate transportation and storage revenue

Our interstate transportation and storage segment's revenues are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines or that is injected into or withdrawn out of our storage facilities. Our interstate transportation and storage segment's contracts can be firm or interruptible.

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Firm transportation and storage contracts require customers to pay certain minimum fixed fees regardless of the volume of commodity transported or stored. In exchange for such fees, we must stand ready to perform a contractually agreed-upon minimum volume of services whenever the customer requests such services. These contracts typically include a variable incremental charge based on the actual volume of transportation commodity throughput or stored commodity injected or withdrawn. Under interruptible transportation and storage contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of commodity they transport across our pipelines or inject into or withdraw out of our storage facilities. Consequently, we are not required to stand ready to provide any contractually agreed-upon volume of service, but instead provides the services based on existing capacity at the time the customer requests the services. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or storage) daily over the life of the contract, which is fundamentally a “stand-ready” service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this “stand-ready” service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of services, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer’s request. Revenue is recognized for interruptible contracts at the time the services are performed.

Midstream revenue

Our midstream segment’s revenues are derived primarily from margins we earn for natural gas volumes that are gathered, processed, and/or transported for our customers. The various types of revenue contracts our midstream segment enters into include:

Fixed fee gathering and processing: Contracts under which we provide gathering and processing services in exchange for a fixed cash fee per unit of volume. Revenue for cash fees is recognized when the service is performed.

Keepwhole: Contracts under which we gather raw natural gas from a third party producer, process the gas to convert it to pipeline quality natural gas, and redeliver to the producer a thermal-equivalent volume of pipeline quality natural gas. In exchange for these services, we retain the NGLs extracted from the raw natural gas received from the producer as well as cash fees paid by the producer. The value of NGLs retained as well as cash fees is recognized as revenue when the services are performed.

Percent of Proceeds (“POP”): Contracts under which we provide gathering and processing services in exchange for a specified percentage of the producer’s commodity (“POP percentage”) and also in some cases additional cash fees. The two types of POP revenue contracts are described below:

- In-Kind POP: We retain our POP percentage (non-cash consideration) and also any additional cash fees in exchange for providing the services. We recognize revenue for the non-cash consideration and cash fees at the time the services are performed.
- Mixed POP: We purchase NGLs from the producer and retain a portion of the residue gas as non-cash consideration for services provided. We may also receive cash fees for such services. Under Topic 606, these agreements were determined to be hybrid agreements which were partially supply agreements (for the NGLs we purchased) and customer agreements (for the services provided related to the product that was returned to the customer). Given that these are hybrid agreements, we split the cash and non-cash consideration between revenue and a reduction of costs based on the value of the service provided vs. the value of the supply received.

Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligations with respect to our midstream segment’s contracts are to provide gathering, transportation and processing services, each of which would be completed on or about the same time, and each of which would be recognized on the same line item on the income statement, therefore identification of separate performance obligations would not impact the timing or geography of revenue recognition.

Certain contracts of our midstream segment include throughput commitments under which customers commit to purchasing a certain minimum volume of service over a specified time period. If such volume of service is not purchased by the customer, deficiency fees are billed to the customer. In some cases, the customer is allowed to apply any deficiency fees paid to future purchases of services. In such cases, we defer revenue recognition until the customer uses the deficiency fees for services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints.

NGL and refined products transportation and services revenue

Our NGL and refined products segment's revenues are primarily derived from transportation, fractionation, blending, and storage of NGL and refined products as well as acquisition and marketing activities. Revenues are generated utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGL markets. Transportation, fractionation, and storage revenue is generated from fees charged to customers under a combination of firm and interruptible contracts. Firm contracts are in the form of take-or-pay arrangements where certain fees will be charged to customers regardless of the volume of service they request for any given period. Under interruptible contracts, customers are not required to pay any fixed minimum amounts, but are instead billed based on actual volume of service provided for any given period. Payment for services under these contracts are typically due the month after the services have been performed.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation, fractionation, blending, or storage) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of services, but such promise is made on a case-by-case basis at the time the customer requests the service and we accept the customer's request. Revenue is recognized for interruptible contracts at the time the services are performed.

Acquisition and marketing contracts are in most cases short-term agreements involving purchase and/or sale of NGL's and other related hydrocarbons at market rates. These contracts were not affected by ASC 606.

Crude oil transportation and services revenue

Our crude oil transportation and service segment are primarily derived from provide transportation, terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest and northeastern United States. Crude oil transportation revenue is generated from tariffs paid by shippers utilizing our transportation services and is generally recognized as the related transportation services are provided. Crude oil terminalling revenue is generated from fees paid by customers for storage and other associated services at the terminal. Crude oil acquisition and marketing revenue is generated from sale of crude oil acquired from a variety of suppliers to third parties. Payment for services under these contracts are typically due the month after the services have been performed.

Certain transportation and terminalling agreements are considered to be firm agreements, because they include fixed fee components that are charged regardless of the volume of crude oil transported by the customer or services provided at the terminal. For these agreements, any fixed fees billed in excess of services provided are not recognized as revenue until the earlier of (i) the time at which the customer applies the fees against cost of service provided in a later period, or (ii) the customer becomes unable to apply the fees against cost of future service due to capacity constraints or contractual terms.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (transportation or terminalling) daily over the life of the contract, which is fundamentally a "stand-ready" service. While there can be multiple activities required to be performed, these activities are not separable because such activities in combination are required to successfully transfer the overall service for which the customer has contracted. The fixed consideration of the transaction price is allocated ratably over the life of the contract and revenue for the fixed consideration is recognized over time, because the customer simultaneously receives and consumes the benefit of this "stand-ready" service. Incremental fees associated with actual volume for each respective period are recognized as revenue in the period the incremental volume of service is performed.

The performance obligation with respect to interruptible contracts is also a promise to provide a single type of service, but such promise is made on a case-by-case basis at the time the customer requests the service and/or product and we accept the customer's request. Revenue is recognized for interruptible contracts at the time the services are performed.

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Acquisition and marketing contracts are in most cases short-term agreements involving purchase and/or sale of crude oil at market rates. These contracts were not affected by ASC 606.

All other revenue

Our all other segment primarily includes our compression equipment business which provides full-service compression design and manufacturing services for the oil and gas industry. It also includes the management of coal and natural resources properties and the related collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. These operations also include end-user coal handling facilities. There were no material changes to the manner in which revenues within this segment are recorded under the new standard.

Contract Balances with Customers

The Partnership satisfies its obligations by transferring goods or services in exchange for consideration from customers. The timing of performance may differ from the timing the associated consideration is paid to or received from the customer, thus resulting in the recognition of a contract asset or a contract liability.

The Partnership recognizes a contract asset when making upfront consideration payments to certain customers or when providing services to customers prior to the time at which the Partnership is contractually allowed to bill for such services. As of September 30, 2018 and January 1, 2018, no contract assets have been recognized.

The Partnership recognizes a contract liability if the customer's payment of consideration precedes the Partnership's fulfillment of the performance obligations. Certain contracts contain provisions requiring customers to pay a fixed fee for a right to use our assets, but allows customers to apply such fees against services to be provided at a future point in time. These amounts are reflected as deferred revenue until the customer applies the deficiency fees to services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints. As of September 30, 2018, the Partnership had $349 million in deferred revenues representing the current value of our future performance obligations.

The amount of revenue recognized for the three and nine months ended September 30, 2018 that was included in the deferred revenue liability balance as of January 1, 2018 was $12 million and $75 million, respectively.

Performance Obligations

At contract inception, the Partnership assesses the goods and services promised in its contracts with customers and identifies a performance obligation for each promise to transfer a good or service (or bundle of goods or services) that is distinct. To identify the performance obligations, the Partnership considers all the goods or services promised in the contract, whether explicitly stated or implied based on customary business practices. For a contract that has more than one performance obligation, the Partnership allocates the total contract consideration it expects to be entitled to, to each distinct performance obligation based on a standalone-selling price basis. Revenue is recognized when (or as) the performance obligations are satisfied, that is, when the customer obtains control of the good or service. Certain of our contracts contain variable components, which, when combined with the fixed component are considered a single performance obligation. For these types of contacts, only the fixed component of the contracts are included in the table below.

As of September 30, 2018, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations is $40.13 billion and the Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	Years Ending December 31, 2018 (remainder)	2019	2020	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of September 30, 2018	$1,426	$5,066	$4,568	$ 29,069	$40,129

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Practical Expedients Utilized by the Partnership

The Partnership elected the following practical expedients in accordance with Topic 606:

- Right to invoice: The Partnership elected to utilize an output method to recognize revenue that is based on the amount to which the Partnership has a right to invoice a customer for services performed to date, if that amount corresponds directly with the value provided to the customer for the related performance or its obligation completed to date. As such, the Partnership recognized revenue in the amount to which it had the right to invoice customers.
- Significant financing component: The Partnership elected not to adjust the promised amount of consideration for the effects of significant financing component if the Partnership expects, at contract inception, that the period between the transfer of a promised good or service to a customer and when the customer pays for that good or service will be one year or less.
- Unearned variable consideration: The Partnership elected to only disclose the unearned fixed consideration associated with unsatisfied performance obligations related to our various customer contracts which contain both fixed and variable components.

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 utilize swaps, futures and other derivative instruments to mitigate the risk associated with market movements in the price of refined products and NGLs to manage our storage facilities and the purchase and sale of purity NGL. These contracts are not designated as hedges for accounting purposes.

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

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The following table details our outstanding commodity-related derivatives:

	September 30, 2018		December 31, 2017	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	358	2018-2019	1,078	2018
Basis Swaps IFERC/NYMEX [(1)]	69,685	2018-2020	48,510	2018-2020
Options – Puts	(17,273)	2019	13,000	2018
Power (Megawatt):				
Forwards	429,720	2018-2019	435,960	2018-2019
Futures	309,123	2018-2019	(25,760)	2018
Options – Puts	157,435	2018-2019	(153,600)	2018
Options – Calls	321,240	2018-2019	137,600	2018
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(7,705)	2018-2021	4,650	2018-2020
Swing Swaps IFERC	69,145	2018-2019	87,253	2018-2019
Fixed Swaps/Futures	(1,784)	2018-2020	(4,700)	2018-2019
Forward Physical Contracts	(54,151)	2018-2020	(145,105)	2018-2020
NGL (MBbls) – Forwards/Swaps	(4,997)	2018-2019	(2,493)	2018-2019
Crude (MBbls) – Forwards/Swaps	35,280	2018-2019	9,172	2018-2019
Refined Products (MBbls) – Futures	(1,521)	2018-2019	(3,783)	2018-2019
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(21,475)	2018-2019	(39,770)	2018
Fixed Swaps/Futures	(21,475)	2018-2019	(39,770)	2018
Hedged Item – Inventory	21,475	2018-2019	39,770	2018

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

Interest Rate Risk

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

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

Term	Type[(1)]	Notional Amount Outstanding September 30, 2018	Notional Amount Outstanding December 31, 2017
July 2018[(2)]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	$ —	$ 300
July 2019[(2)]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	400	300
July 2020[(2)]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	400
July 2021[(2)]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	400	—
December 2018	Pay a floating rate 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.

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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, 2018	December 31, 2017	September 30, 2018	December 31, 2017
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$—	$ 14	$(6)	$ (2)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	477	262	(537)	(281)
Commodity derivatives	122	44	(327)	(55)
Interest rate derivatives	—	—	(97)	(219)
	599	306	(961)	(555)
Total derivatives	$599	$ 320	$(967)	$ (557)

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:

	Balance Sheet Location	Asset Derivatives		Liability Derivatives	
		September 30, 2018	December 31, 2017	September 30, 2018	December 31, 2017
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$(97)	$ (219)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	122	44	(327)	(55)
Broker cleared derivative contracts	Other current assets (liabilities)	477	276	(543)	(283)
Total gross derivatives		599	320	(967)	(557)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(29)	(20)	29	20
Counterparty netting	Other current assets (liabilities)	(477)	(263)	477	263
Total net derivatives		$ 93	$ 37	$(461)	$ (274)

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

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

	Location of Gain Recognized in Income on Derivatives	Amount of Gain Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2018	2017	2018	2017
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ —	$ 2	$ 9	$ 4

	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,	
		2018	2017	2018	2017
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$3	$(5)	$36	$21
Commodity derivatives – Non-trading	Cost of products sold	21	(12)	(352)	(15)
Interest rate derivatives	Gains (losses) on interest rate derivatives	45	(8)	117	(28)
Embedded derivatives	Other, net	—	—	—	1
Total		$69	$(25)	$(199)	$(21)

13. RELATED PARTY TRANSACTIONS

The Partnership 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,	
	2018	2017	2018	2017
Affiliated revenues	$192	$190	$700	$441

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

	September 30, 2018	December 31, 2017
Accounts receivable from related companies:		
ETE	$ 42	$ —
FGT	15	11
Phillips 66	30	20
Sunoco LP	207	219
Trans-Pecos Pipeline, LLC	10	1
Other	29	67
Total accounts receivable from related companies:	$ 333	$ 318
Accounts payable to related companies:		
Sunoco LP	$ 178	$ 195
USAC	45	—
Other	64	14
Total accounts payable to related companies:	$ 287	$ 209

	September 30, 2018	December 31, 2017
Long-term notes receivable from related company:		
Sunoco LP	$ 85	$ 85

14. REPORTABLE SEGMENTS

Our consolidated 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.

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, refined product 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

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unrealized gains and losses on commodity derivatives and inventory fair value 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,	
	2018	2017	2018	2017
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$846	$729	$2,424	$2,196
Intersegment revenues	76	44	186	146
	922	773	2,610	2,342
Interstate transportation and storage:				
Revenues from external customers	390	220	1,026	652
Intersegment revenues	5	4	13	14
	395	224	1,039	666
Midstream:				
Revenues from external customers	537	665	1,571	1,863
Intersegment revenues	1,716	1,100	4,170	3,154
	2,253	1,765	5,741	5,017
NGL and refined products transportation and services:				
Revenues from external customers	2,948	1,989	7,878	5,874
Intersegment revenues	115	81	299	241
	3,063	2,070	8,177	6,115
Crude oil transportation and services:				
Revenues from external customers	4,422	2,714	12,942	7,749
Intersegment revenues	16	11	44	16
	4,438	2,725	12,986	7,765
All other:				
Revenues from external customers	498	656	1,490	2,110
Intersegment revenues	27	27	108	139
	525	683	1,598	2,249
Eliminations	(1,955)	(1,267)	(4,820)	(3,710)
Total revenues	$9,641	$6,973	$27,331	$20,444

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	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017*	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017*
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$221	$163	$621	$480
Interstate transportation and storage	416	273	1,069	800
Midstream	434	356	1,225	1,088
NGL and refined products transportation and services	498	439	1,410	1,208
Crude oil transportation and services	682	420	1,694	835
All other	78	133	242	363
Total	2,329	1,784	6,261	4,774
Depreciation, depletion and amortization	(636)	(596)	(1,827)	(1,713)
Interest expense, net	(387)	(352)	(1,091)	(1,020)
Gain on Sunoco LP common unit repurchase	—	—	172	—
Loss on deconsolidation of CDM	—	—	(86)	—
Gains (losses) on interest rate derivatives	45	(8)	117	(28)
Non-cash compensation expense	(20)	(19)	(61)	(57)
Unrealized gains (losses) on commodity risk management activities	97	(81)	(255)	17
Adjusted EBITDA related to unconsolidated affiliates	(257)	(279)	(670)	(765)
Equity in earnings of unconsolidated affiliates	113	127	147	139
Other, net	13	27	100	79
Income before income tax (expense) benefit	$1,297	$603	$2,807	$1,426

* As adjusted. See Note 1.

	September 30, 2018	December 31, 2017
Assets:		
Intrastate transportation and storage	$ 5,874	$ 5,020
Interstate transportation and storage	14,143	13,518
Midstream	20,175	20,004
NGL and refined products transportation and services	18,438	17,600
Crude oil transportation and services	17,458	17,736
All other	3,068	4,087
Total assets	$ 79,156	$ 77,965

15. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

Sunoco Logistics Partners Operations L.P., a subsidiary of ETP, is the issuer of multiple series of senior notes that are guaranteed by ETP. These guarantees are full and unconditional. For the purposes of this footnote, Energy Transfer Operating, 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.

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

	September 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$—	$—	$ 379	$—	$ 379
All other current assets	4	56	6,806	(892)	5,974
Property, plant and equipment, net	—	—	60,550	—	60,550
Investments in unconsolidated affiliates	49,614	12,435	3,599	(62,049)	3,599
All other assets	8	75	8,571	—	8,654
Total assets	$49,626	$12,566	$ 79,905	$(62,941)	$ 79,156
Current liabilities	$(1,118)	$(3,407)	$ 14,675	$(892)	$ 9,258
Non-current liabilities	22,823	7,605	4,794	—	35,222
Noncontrolling interest	—	—	6,334	—	6,334
Total partners’ capital	27,921	8,368	54,102	(62,049)	28,342
Total liabilities and equity	$49,626	$12,566	$ 79,905	$(62,941)	$ 79,156

	December 31, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$—	$(3)	$ 309	$—	$ 306
All other current assets	—	159	6,063	—	6,222
Property, plant and equipment, net	—	—	58,437	—	58,437
Investments in unconsolidated affiliates	48,378	11,648	3,816	(60,026)	3,816
All other assets	—	—	9,184	—	9,184
Total assets	$48,378	$11,804	$ 77,809	$(60,026)	$ 77,965
Current liabilities	$(1,496)	$(3,660)	$ 12,150	$—	$ 6,994
Non-current liabilities	21,604	7,607	7,609	—	36,820
Noncontrolling interest	—	—	5,882	—	5,882
Total partners’ capital	28,270	7,857	52,168	(60,026)	28,269
Total liabilities and equity	$48,378	$11,804	$ 77,809	$(60,026)	$ 77,965

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	Three Months Ended September 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$ —	$ 9,641	$ —	$ 9,641
Operating costs, expenses, and other	—	—	8,136	—	8,136
Operating income	—	—	1,505	—	1,505
Interest expense, net	(303)	(55)	(29)	—	(387)
Equity in earnings of unconsolidated affiliates	1,394	501	113	(1,895)	113
Gains on interest rate derivatives	45	—	—	—	45
Other, net	—	—	21	—	21
Income before income tax benefit	1,136	446	1,610	(1,895)	1,297
Income tax benefit	—	—	(61)	—	(61)
Net income	1,136	446	1,671	(1,895)	1,358
Less: Net income attributable to noncontrolling interest	—	—	223	—	223
Net income attributable to partners	$1,136	$ 446	$ 1,448	$ (1,895)	$ 1,135
Other comprehensive income	$—	$ —	$ 4	$ —	$ 4
Comprehensive income	1,136	446	1,675	(1,895)	1,362
Comprehensive income attributable to noncontrolling interest	—	—	223	—	223
Comprehensive income attributable to partners	$1,136	$ 446	$ 1,452	$ (1,895)	$ 1,139

	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	—	—	6,194	—	6,194
Operating income	—	—	779	—	779
Interest expense, net	—	(32)	(320)	—	(352)
Equity in earnings of unconsolidated affiliates	647	236	127	(883)	127
Losses on interest rate derivatives	—	—	(8)	—	(8)
Other, net	—	1	56	—	57
Income before income tax benefit	647	205	634	(883)	603
Income tax benefit	—	—	(112)	—	(112)
Net income	647	205	746	(883)	715
Less: Net income attributable to noncontrolling interest	—	—	110	—	110
Net income attributable to partners	$647	$ 205	$ 636	$ (883)	$ 605
Other comprehensive income	$—	$ —	$ 7	$ —	$ 7
Comprehensive income	647	205	753	(883)	722
Comprehensive income attributable to noncontrolling interest	—	—	110	—	110
Comprehensive income attributable to partners	$647	$ 205	$ 643	$ (883)	$ 612

* As adjusted. See Note 1.

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	Nine Months Ended September 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$ —	$ 27,331	$ —	$ 27,331
Operating costs, expenses, and other	—	—	23,910	—	23,910
Operating income	—	—	3,421	—	3,421
Interest expense, net	(870)	(137)	(84)	—	(1,091)
Equity in earnings of unconsolidated affiliates	3,036	827	147	(3,863)	147
Gain on Sunoco LP unit repurchase	—	—	172	—	172
Loss on deconsolidation of CDM	—	—	(86)	—	(86)
Gains on interest rate derivatives	117	—	—	—	117
Other, net	—	—	127	—	127
Income before income tax benefit	2,283	690	3,697	(3,863)	2,807
Income tax benefit	—	—	(32)	—	(32)
Net income	2,283	690	3,729	(3,863)	2,839
Less: Net income attributable to noncontrolling interest	—	—	557	—	557
Net income attributable to partners	$2,283	$ 690	$ 3,172	$ (3,863)	$ 2,282
Other comprehensive income	$—	$ —	$ 7	$ —	$ 7
Comprehensive income	2,283	690	3,736	(3,863)	2,846
Comprehensive income attributable to noncontrolling interest	—	—	557	—	557
Comprehensive income attributable to partners	$2,283	$ 690	$ 3,179	$ (3,863)	$ 2,289

	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	18,245	—	18,246
Operating income (loss)	—	(1)	2,199	—	2,198
Interest expense, net	—	(113)	(907)	—	(1,020)
Equity in earnings of unconsolidated affiliates	1,657	1,001	139	(2,658)	139
Losses on interest rate derivatives	—	—	(28)	—	(28)
Other, net	—	4	134	(1)	137
Income before income tax expense	1,657	891	1,537	(2,659)	1,426
Income tax expense	—	—	22	—	22
Net income	1,657	891	1,515	(2,659)	1,404
Less: Net income attributable to noncontrolling interest	—	—	266	—	266
Net income attributable to partners	$1,657	$ 891	$ 1,249	$ (2,659)	$ 1,138
Other comprehensive income	$—	$ —	$ 6	$ —	$ 6
Comprehensive income	1,657	891	1,521	(2,659)	1,410
Comprehensive income attributable to noncontrolling interest	—	—	266	—	266
Comprehensive income attributable to partners	$1,657	$ 891	$ 1,255	$ (2,659)	$ 1,144

* As adjusted. See Note 1.

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	Nine Months Ended September 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$2,753	$ 582	$ 3,843	$ (2,078)	$ 5,100
Cash flows used in investing activities	(834)	(579)	(3,732)	2,078	(3,067)
Cash flows used in financing activities	(1,919)	—	(41)	—	(1,960)
Change in cash	—	3	70	—	73
Cash at beginning of period	—	(3)	309	—	306
Cash at end of period	$—	$ —	$ 379	$ —	$ 379

	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

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

(Tabular dollar and unit amounts 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 the Partnership's Annual Report on Form 10-K filed with the SEC on February 23, 2018. 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, 2017 filed with the SEC on February 23, 2018.

References to "we," "us," "our," the "Partnership" and "ETP" shall mean Energy Transfer Operating, L.P. (formerly Energy Transfer Partners, L.P.) and its subsidiaries.

OVERVIEW

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

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

Permian Gulf Coast Pipeline Joint Venture

In September 2018, ETP, Magellan Midstream Partners, L.P., MPLX LP and Delek US Holdings, Inc. announced that they have received sufficient commitments to proceed with plans to construct a new 30-inch diameter common carrier pipeline, the Permian Gulf Coast ("PGC") pipeline, to transport crude oil from the Permian Basin to the Texas Gulf Coast region. The 600-mile PGC pipeline system is expected to be operational in mid-2020 with multiple Texas origins. The pipeline system will have the strategic capability to transport crude oil to ETP's Nederland, Texas terminal for ultimate delivery through its distribution system. The project is subject to receipt of customary regulatory and Board approvals of the respective entities.

ETE and ETP Simplification Transaction

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

Immediately prior to the closing of the ETE-ETP Merger, the following also occurred:

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

Immediately prior to the closing of the ETE-ETP Merger, ETE contributed the following to ETP:

- 2,263,158 common units representing limited partner interests in Sunoco LP to ETP in exchange for 2,874,275 ETP common units;
- 100 percent of the limited liability company interests in Sunoco GP LLC, the sole general partner of Sunoco LP, and all of the IDRs in Sunoco LP, to ETP in exchange for 42,812,389 ETP common units;
- 12,466,912 common units representing limited partner interests in USAC and 100 percent of the limited liability company interests in USA Compression GP, LLC, the general partner of USAC, to ETP in exchange for 16,134,903 ETP common units; and

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• a 100 percent limited liability company interest in Lake Charles LNG and a 60 percent limited liability company interest in each of Energy Transfer LNG Export, LLC, ET Crude Oil Terminals, LLC and ETC Illinois LLC to ETP in exchange for 37,557,815 ETP common units.

Series D Preferred Units Issuance

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

ETP Senior Notes Offering and Redemption

In June 2018, ETP issued $500 million aggregate principal amount of 4.20% senior notes due 2023, $1.00 billion aggregate principal amount of 4.95% senior notes due 2028, $500 million aggregate principal amount of 5.80% senior notes due 2038 and $1.00 billion aggregate principal amount of 6.00% senior notes due 2048. The $2.96 billion net proceeds from the offering were used to redeem outstanding senior notes, to repay borrowings outstanding under ETP's revolving credit facility and for general partnership purposes.

Old Ocean Joint Venture Formation

In May 2018, ETP and Enterprise Products Partners L.P. announced the formation of a joint venture to resume service on the Old Ocean natural gas pipeline. The 24-inch diameter pipeline resumed service in May 2018 and ETP is the operator. Additionally, both parties are in the process of expanding their jointly owned North Texas 36-inch pipeline that will provide more capacity from West Texas for deliveries into the Old Ocean pipeline. The North Texas pipeline expansion project is expected to be complete by January 1, 2019.

Acquisition of HPC

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

Series C Preferred Units Issuance

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

CDM Contribution

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

In connection with the CDM Contribution, ETE acquired (i) all of the outstanding limited liability company interests in USA Compression GP, LLC, the general partner of USAC, and (ii) 12,466,912 USAC common units for cash consideration equal to $250 million.

New Ethane Export Facility Joint Venture

In March 2018, ETP and Satellite Petrochemical USA Corp. ("Satellite") entered into definitive agreements to form a joint venture, Orbit Gulf Coast NGL Exports, LLC ("Orbit"), with the purpose of constructing a new export terminal on the United States Gulf Coast to provide ethane to Satellite for consumption at their ethane cracking facilities in China. At the terminal, Orbit will construct an 800 MBbls refrigerated ethane storage tank, a 175 MBbls/d ethane refrigeration facility and a 20-inch ethane pipeline originating at ETP's Mont Belvieu Fractionators that will make deliveries to the terminal as well as domestic markets in the region. ETP will be the operator of the Orbit assets, provide storage and marketing services for Satellite and provide Satellite with approximately 150 MBbls/d of ethane under a long-term, demand-based agreement. Additionally, ETP will construct and

wholly own the infrastructure that is required to both supply ethane to the pipeline and to load the ethane on to very large ethane carriers destined for Satellite's newly constructed ethane crackers in China's Jiangsu Province. Subject to Chinese Governmental approval, it is anticipated that the Orbit export terminal will be ready for commercial service in the fourth quarter of 2020.

Sunoco LP Common Unit Repurchase

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

Regulatory Update

Interstate Natural Gas Transportation Regulation

Effective December 22, 2017, the 2017 Tax and Jobs Act (the "Tax Act") changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related proposals, the FERC addressed treatment of federal income tax allowances in regulated entity rates. The FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost of service rates. The FERC issued the Revised Policy Statement in response to a remand from the United States Court of Appeals for the District of Columbia Circuit in United Airlines v. FERC, in which the court determined that the FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not "double recover" its taxes under the current policy by both including an income-tax allowance in its cost of service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, the FERC issued an order denying requests for rehearing and clarification of its Revised Policy Statement because it is non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs. In light of the rehearing order, the impacts of the FERC's policy on the treatment of income taxes may have on the rates ETP can charge for the FERC regulated transportation services are unknown at this time.

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

Included in the March 15, 2018 proposals is a Notice of Proposed Rulemaking ("NOPR") proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, the FERC issued a Final Rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires all FERC regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information and to make an election on how to treat its existing rates. The Final Rule suggests that this information will allow the FERC and other stakeholders to evaluate the impacts of the Tax Act and the Revised Policy Statement on each individual pipeline's rates. The Final Rule also requires that each FERC regulated natural gas pipeline select one of four options: file a limited Natural Gas Act ("NGA") Section 4 filing reducing its rates only as required related to the Tax Act and the Revised Policy Statement, commit to filing a general NGA Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. For the limited NGA Section 4 option, the FERC clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. Trunkline, ETC

Tiger Pipeline, LLC and Panhandle filed their respective FERC Form No. 501-Gs on October 11, 2018. FEP, Lake Charles LNG and certain other operating subsidiaries are scheduled to file their respective FERC Form No. 501-Gs by November 8, 2018. Rover, FGT, Transwestern and MEP are scheduled to file their respective FERC Form No. 501-Gs by December 6, 2018. At this time, we cannot predict the outcome of the Final Rule, but adoption of the regulation could ultimately result in a rate proceeding that may impact the rates ETP is permitted to charge its customers for FERC regulated transportation services.

Even without action on the 2017 Tax Law NOI or as contemplated in the Final Rule, the FERC or our shippers may challenge the cost of service rates we charge. The FERC's establishment of a just and reasonable rate is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect the FERC's determination of just and reasonable cost of service rates. Although changes in these two tax related components may decrease, other components in the cost of service rate calculation may

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increase and result in a newly calculated cost of service rate that is the same as or greater than the prior cost of service rate. Moreover, we receive revenues from our pipelines based on a variety of rate structures, including cost of service rates, negotiated rates, discounted rates and market-based rates. Many of our interstate pipelines, such as ETC Tiger Pipeline, LLC, MEP and FEP, have negotiated market rates that were agreed to by customers in connection with long-term contracts entered into to support the construction of the pipelines. Other systems, such as FGT, Transwestern and Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. We do not expect market-based rates, negotiated rates or discounted rates that are not tied to the cost of service rates to be affected by the Revised Policy Statement or any final regulations that may result from the March 15, 2018 proposals. The revenues we receive from natural gas transportation services we provide pursuant to cost of service based rates may decrease in the future as a result of the ultimate outcome of the NOI, the Final Rule, and the Revised Policy Statement, combined with the reduced corporate federal income tax rate established in the Tax Act. The extent of any revenue reduction related to our cost of service rates, if any, will depend on a detailed review of all of ETP’s cost of service components and the outcomes of any challenges to our rates by the FERC or our shippers.

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

Interstate Liquids Transportation Regulation

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

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. 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.

As discussed in Note 1 of the Partnership’s consolidated financial statements included in “Item 1. Financial Statements,” during the fourth quarter of 2017, the Partnership elected to change its method of inventory costing to weighted-average cost for certain

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inventory that had previously been accounted for using the last-in, first-out ("LIFO") method. The inventory impacted by this change included the crude oil, refined products and NGLs associated with the legacy Sunoco Logistics business. These changes have been applied retrospectively to all periods presented, and the prior period amounts reflected below have been adjusted from those amounts previously reported.

Consolidated Results

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017*	Change	2018	2017*	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$221	$163	$ 58	$621	$480	$141
Interstate transportation and storage	416	273	143	1,069	800	269
Midstream	434	356	78	1,225	1,088	137
NGL and refined products transportation and services	498	439	59	1,410	1,208	202
Crude oil transportation and services	682	420	262	1,694	835	859
All other	78	133	(55)	242	363	(121)
Total	2,329	1,784	545	6,261	4,774	1,487
Depreciation, depletion and amortization	(636)	(596)	(40)	(1,827)	(1,713)	(114)
Interest expense, net	(387)	(352)	(35)	(1,091)	(1,020)	(71)
Gain on Sunoco LP common unit repurchase	—	—	—	172	—	172
Loss on deconsolidation of CDM	—	—	—	(86)	—	(86)
Gains (losses) on interest rate derivatives	45	(8)	53	117	(28)	145
Non-cash compensation expense	(20)	(19)	(1)	(61)	(57)	(4)
Unrealized gains (losses) on commodity risk management activities	97	(81)	178	(255)	17	(272)
Adjusted EBITDA related to unconsolidated affiliates	(257)	(279)	22	(670)	(765)	95
Equity in earnings of unconsolidated affiliates	113	127	(14)	147	139	8
Other, net	13	27	(14)	100	79	21
Income before income tax (expense) benefit	1,297	603	694	2,807	1,426	1,381
Income tax (expense) benefit	61	112	(51)	32	(22)	54
Net income	$1,358	$715	$ 643	$2,839	$1,404	$1,435

* As adjusted.

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, 2018 compared to the same period last year primarily due to additional depreciation from assets recently placed in service. These increases were partially offset by the deconsolidation of CDM in April 2018, which reduced depreciation and amortization expense by $43 million and $78 million for the three and nine months ended September 30, 2018, respectively, compared to the prior periods.

Interest Expense, net. Interest expense, net of capitalized interest, increased for the three and nine months ended September 30, 2018 compared to the same period last year primarily attributable to increases in long-term debt from ETP senior note issuances, partially offset by a decrease in credit facility borrowings.

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Gain on Sunoco LP Common Unit Repurchase. In connection with Sunoco LP's repurchase of its common units in February 2018, the Partnership recognized a gain of $172 million during the nine months ended September 30, 2018.
Loss on Deconsolidation of CDM. In connection with the CDM Contribution in April 2018, the Partnership deconsolidated CDM and recognized a loss of $86 million during the nine months ended September 30, 2018.
Gains (Losses) on Interest Rate Derivatives. Gains on interest rate derivatives during the three and nine months ended September 30, 2018 resulted from increases 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.
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 three and nine months ended September 30, 2018 compared to the same period last year, income tax expense decreased primarily due to the decrease in federal corporate income tax rate per the Tax Act as well as $109 million and $179 million, respectively, of deferred tax benefit adjustments during the three and nine months ended September 30, 2018 as the result of a state statutory rate reduction.

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Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$42	$35	$ 7	$102	$86	$ 16
FEP	14	14	—	41	39	2
MEP	7	9	(2)	24	29	(5)
Sunoco LP	29	35	(6)	(106)	(89)	(17)
USAC	(4)	—	(4)	(6)	—	(6)
Other	25	34	(9)	92	74	18
Total equity in earnings of unconsolidated affiliates	$113	$127	$ (14)	$147	$139	$ 8
Adjusted EBITDA related to unconsolidated affiliates[(1)]:						
Citrus	$96	$99	$ (3)	$256	$262	$ (6)
FEP	19	18	1	56	55	1
MEP	20	23	(3)	62	66	(4)
Sunoco LP	58	74	(16)	126	211	(85)
USAC	20	—	20	41	—	41
Other	44	65	(21)	129	171	(42)
Total Adjusted EBITDA related to unconsolidated affiliates	$257	$279	$ (22)	$670	$765	$ (95)
Distributions received from unconsolidated affiliates:						
Citrus	$52	$50	$ 2	$125	$113	$ 12
FEP	18	18	—	50	28	22
MEP	9	13	(4)	40	106	(66)
Sunoco LP	21	36	(15)	79	108	(29)
USAC	10	—	10	20	—	20
Other	34	27	7	76	80	(4)
Total distributions received from unconsolidated affiliates	$144	$144	$ —	$390	$435	$ (45)

(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.

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- Unrealized gains or losses on commodity risk management activities. 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.

Following is a reconciliation of ETP's segment margin to operating income, as reported in its consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Segment Margin:				
Intrastate transportation and storage	$284	$167	$722	$551
Interstate transportation and storage	395	224	1,039	666
Midstream	622	530	1,768	1,614
NGL and refined products transportation and services	634	483	1,821	1,558
Crude oil transportation and services	944	548	1,954	1,194
All other	25	112	177	290
Intersegment eliminations	(8)	(13)	(23)	(24)
Total segment margin	2,896	2,051	7,458	5,849
Less:				
Operating expenses	632	571	1,863	1,603
Depreciation, depletion and amortization	636	596	1,827	1,713
Selling, general and administrative	123	105	347	335
Operating income	$1,505	$779	$3,421	$2,198

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Intrastate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Natural gas transported (BBtu/d)	12,146	8,951	3,195	10,592	8,698	1,894
Withdrawals from storage natural gas inventory (BBtu)	—	—	—	17,703	23,093	(5,390)
Revenues	$922	$773	$ 149	$2,610	$2,342	$ 268
Cost of products sold	638	606	32	1,888	1,791	97
Segment margin	284	167	117	722	551	171
Unrealized (gains) losses on commodity risk management activities	(12)	22	(34)	33	16	17
Operating expenses, excluding non-cash compensation expense	(51)	(40)	(11)	(141)	(124)	(17)
Selling, general and administrative expenses, excluding non-cash compensation expense	(7)	(6)	(1)	(20)	(17)	(3)
Adjusted EBITDA related to unconsolidated affiliates	6	19	(13)	26	53	(27)
Other	1	1	—	1	1	—
Segment Adjusted EBITDA	$221	$163	$ 58	$621	$480	$ 141

Volumes. For the three and nine months ended September 30, 2018 compared to the same period last year, transported volumes increased primarily due to favorable market pricing, as well as the impact of reflecting RIGS as a consolidated subsidiary beginning in April 2018, as discussed in “Recent Developments” above.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Transportation fees	$141	$109	$ 32	$392	$337	$ 55
Natural gas sales and other (excluding unrealized gains and losses)	110	55	55	309	149	160
Retained fuel revenues (excluding unrealized gains and losses)	16	15	1	42	43	(1)
Storage margin (excluding unrealized gains and losses)	5	10	(5)	12	38	(26)
Unrealized gains (losses) on commodity risk management activities	12	(22)	34	(33)	(16)	(17)
Total segment margin	$284	$167	$ 117	$722	$551	$ 171

Segment Adjusted EBITDA. For the three months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP’s intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $55 million in realized natural gas sales and other margin due to higher realized gains from pipeline optimization activity;
- an increase of $7 million in transportation fees, excluding the incremental transportation fees related to the RIGS consolidation discussed above, primarily due to new contracts and the impact of the Red Bluff Express pipeline coming online in May 2018; and
- a net increase of $6 million due to the consolidation of RIGS beginning in April 2018, as discussed in “Recent Developments” above, resulting in increases in transportation fees, operating expenses, and selling, general and administrative expenses of

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$25 million, $5 million and $2 million, respectively, and a decrease of $12 million in Adjusted EBITDA related to unconsolidated affiliates; partially offset by

- a decrease of $5 million in realized storage margin primarily due to lower realized derivative gains.

Segment Adjusted EBITDA. For the nine months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $160 million in realized natural gas sales and other margin due to higher realized gains from pipeline optimization activity;
- an increase of $6 million in transportation fees, excluding the impact of consolidating RIGS as discussed above, primarily due to new contracts and the impact of the Red Bluff Express pipeline coming online in May 2018; and
- a net increase of $3 million due to the consolidation of RIGS beginning in April 2018, as discussed in "Recent Developments" above, resulting in increases in transportation fees, operating expenses, and selling, general and administrative expenses of $49 million, $11 million and $4 million, respectively, and a decrease of $31 million in Adjusted EBITDA related to unconsolidated affiliates; partially offset by
- a decrease of $26 million in realized storage margin primarily due to an adjustment to the Bammel storage inventory; and
- a decrease of $1 million in retained fuel revenues due to lower natural gas pricing.

Interstate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Natural gas transported (BBtu/d)	10,155	6,075	4,080	9,029	5,678	3,351
Natural gas sold (BBtu/d)	18	19	(1)	17	18	(1)
Revenues	$395	$224	$171	$1,039	$666	$373
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(97)	(79)	(18)	(296)	(220)	(76)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(19)	(14)	(5)	(53)	(33)	(20)
Adjusted EBITDA related to unconsolidated affiliates	135	140	(5)	374	383	(9)
Other	2	2	—	5	4	1
Segment Adjusted EBITDA	$416	$273	$143	$1,069	$800	$269

Volumes. For the three months ended September 30, 2018 compared to the same period last year, transported volumes reflected an increase of 2,225 BBtu/d as a result of the initiation of service on the Rover pipeline; increases of 772 BBtu/d and 625 BBtu/d on the Panhandle and Trunkline pipelines, respectively, due to increased utilization of higher contracted capacity; and an increase of 398 BBtu/d on the Tiger pipeline as a result of production increases in the Haynesville Shale and deliveries into intrastate markets.

For the nine months ended September 30, 2018 compared to the same period last year, transported volumes reflected increases of 1,817 BBtu/d as a result of the initiation of service on the Rover pipeline; increases of 594 BBtu/d and 428 BBtu/d on the Panhandle and Trunkline pipelines, respectively, due to higher demand resulting from colder weather and increased utilization by the Rover pipeline; 397 BBtu/d on the Tiger pipeline as a result of production increases in the Haynesville Shale and deliveries into the intrastate markets and 104 BBtu/d on the Transwestern pipeline resulting from favorable market opportunities in the midcontinent and Waha areas from the Permian supply basin.

Segment Adjusted EBITDA. For the three months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $128 million associated with the Rover pipeline with increases of $149 million in revenues, $14 million in net operating expenses and $7 million in selling, general and administrative expenses; and

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- an aggregate increase of $22 million in revenues, excluding the incremental revenue related to the Rover pipeline discussed above, primarily due to capacity sold at higher rates on the Transwestern and Panhandle pipelines; partially offset by
- an increase of $4 million in operating expenses, excluding the incremental expenses related to the Rover pipeline discussed above, primarily due to slightly higher system gas expense and higher maintenance project costs due to scope and level of activity, offset by lower ad valorem taxes due to favorable valuations; and
- a decrease of $5 million in Adjusted EBITDA related to unconsolidated affiliates primarily related to sale of capacity on MEP at lower rates and lower sales of short term firm capacity on Citrus.

Segment Adjusted EBITDA. For the nine months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's interstate transportation and storage segment increased due to the net impacts of the following:

- An increase of $247 million associated with the Rover pipeline with increases of $336 million in revenues, $70 million in net operating expenses and $19 million in selling, general and administrative expenses; and
- an aggregate increase of $45 million in revenues, excluding the incremental revenues related to the Rover pipeline discussed above, primarily due to capacity sold at higher rates on the Transwestern and Panhandle pipelines, partially offset by $8 million of lower reservation revenues on the Tiger pipeline due to a customer contract restructuring; partially offset by
- an increase of $6 million in operating expenses, excluding the incremental expenses related to the Rover pipeline discussed above, primarily due to higher maintenance project costs; and
- a decrease of $9 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to lower sales of short term firm capacity on Citrus and lower margins on MEP due to lower rates on renewals of expiring long term contracts, partially offset by lower legal fees on Citrus.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Gathered volumes (BBtu/d)	12,774	11,090	1,684	11,890	10,764	1,126
NGLs produced (MBbls/d)	583	453	130	533	461	72
Equity NGLs (MBbls/d)	32	27	5	31	27	4
Revenues	$2,253	$1,765	$488	$5,741	$5,017	$724
Cost of products sold	1,631	1,235	396	3,973	3,403	570
Segment margin	622	530	92	1,768	1,614	154
Unrealized (gains) losses on commodity risk management activities	—	1	(1)	—	(18)	18
Operating expenses, excluding non-cash compensation expense	(179)	(157)	(22)	(512)	(470)	(42)
Selling, general and administrative expenses, excluding non-cash compensation expense	(19)	(26)	7	(59)	(60)	1
Adjusted EBITDA related to unconsolidated affiliates	9	6	3	25	20	5
Other	1	2	(1)	3	2	1
Segment Adjusted EBITDA	$434	$356	$78	$1,225	$1,088	$137

Volumes. For the three and nine months ended September 30, 2018 compared to the same periods last year, gathered volumes and NGL production increased primarily due to increases in the North Texas, Permian and Northeast regions, partially offset by smaller declines in other regions.

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Segment Margin. The components of ETP's midstream segment margin were as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Gathering and processing fee-based revenues	$456	$418	$ 38	$1,330	$1,262	$ 68
Non-fee-based contracts and processing (excluding unrealized gains and losses)	166	113	53	438	334	104
Unrealized gains (losses) on commodity risk management activities	—	(1)	1	—	18	(18)
Total segment margin	$622	$530	$ 92	$1,768	$1,614	$ 154

Segment Adjusted EBITDA. For the three months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's midstream segment increased due to the net impacts of the following:

- an increase of $38 million in fee-based margin due to growth in the North Texas, Permian and Northeast regions, offset by declines in the Ark-La-Tex and midcontinent/Panhandle regions;
- an increase of $27 million in non-fee-based margin due to increased throughput volume in the South Texas and Permian regions;
- an increase of $26 million in non-fee-based margin primarily due to higher crude oil and NGL prices;
- a decrease of $7 million in selling, general and administrative expenses primarily due to a decrease of $3 million in merger and acquisition costs and a $3 million change in capitalized overhead; and
- an increase of $3 million in Adjusted EBITDA related to unconsolidated affiliates due to higher earnings from ETP's Aqua, Mi Vida and Ranch joint ventures; partially offset by
- an increase of $22 million in operating expenses due to increases of $6 million in materials, $5 million in outside services and $4 million in maintenance project costs, as well as a $7 million change in capitalized overhead.

Segment Adjusted EBITDA. For the nine months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's midstream segment increased due to the net impacts of the following:

- an increase of $68 million in fee-based margin due to growth in the North Texas, Permian and Northeast regions, offset by declines in the Ark-La-Tex and midcontinent/Panhandle regions;
- an increase of $57 million in non-fee-based margin primarily due to higher crude oil and NGL prices;
- an increase of $47 million in non-fee-based margin due to increased throughput volume in the North Texas and Permian regions;
- an increase of $5 million in Adjusted EBITDA related to unconsolidated affiliates due to higher earnings from ETP's Aqua, Mi Vida and Ranch joint ventures; and
- a decrease of $1 million in selling, general and administrative expenses primarily due to lower office expenses; partially offset by
- an increase of $42 million in operating expenses primarily due to increases of $13 million in outside services, $12 million in materials, $8 million in employee costs and $4 million in maintenance project costs as well as a $3 million change in capitalized overhead.

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NGL and Refined Products Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
NGL transportation volumes (MBbls/d)	1,086	836	250	997	829	168
Refined products transportation volumes (MBbls/d)	627	612	15	628	626	2
NGL and refined products terminal volumes (MBbls/d)	858	782	76	784	780	4
NGL fractionation volumes (MBbls/d)	567	390	177	505	418	87
Revenues	$3,063	$2,070	$ 993	$8,177	$6,115	$2,062
Cost of products sold	2,429	1,587	842	6,356	4,557	1,799
Segment margin	634	483	151	1,821	1,558	263
Unrealized losses on commodity risk management activities	26	56	(30)	26	2	24
Operating expenses, excluding non-cash compensation expense	(168)	(106)	(62)	(448)	(358)	(90)
Selling, general and administrative expenses, excluding non-cash compensation expense	(17)	(13)	(4)	(52)	(49)	(3)
Adjusted EBITDA related to unconsolidated affiliates	23	19	4	63	54	9
Other	—	—	—	—	1	(1)
Segment Adjusted EBITDA	$498	$439	$ 59	$1,410	$1,208	$202

Volumes. For the three and nine months ended September 30, 2018 compared to the same periods last year, NGL transportation volumes increased primarily from the Permian region resulting from a ramp up in production from existing customers, higher throughput volumes on Mariner West driven by end user facility constraints in the prior period and higher throughput from Mariner South.

Refined products transportation volumes increased for the three and nine months ended September 30, 2018 compared to the same periods last year primarily due to higher throughput volumes from the Northeast and Southwest regions, partially offset by decreased throughput volumes from the Midwest region.

NGL and refined products terminal volumes increased for the three months ended September 30, 2018 compared to the same period last year primarily due to more volumes loaded at ETP’s Nederland terminal as propane export demand increased, as well as higher throughput volumes at ETP’s Marcus Hook Industrial Complex primarily due to increased production from the Marcellus region. For the nine months ended September 30, 2018 compared to the same period last year, NGL and refined products terminal volumes increased primarily due to more volumes loaded at ETP’s Nederland terminal as propane export demand increased, partially offset by lower refined product throughput volumes at ETP’s Eagle Point terminal and lower volumes at ETP’s refined products marketing terminals.

Average fractionated volumes at ETP’s Mont Belvieu, Texas fractionation facility increased 45% and 21% for the three and nine months ended September 30, 2018, respectively, compared to the same periods last year primarily due to the commissioning of ETP’s fifth fractionator in July 2018 as well as increased volumes from Permian producers.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Fractionators and refinery services margin	$162	$115	$ 47	$424	$352	$ 72
Transportation margin	322	246	76	878	720	158
Storage margin	50	50	—	154	160	(6)
Terminal services margin	109	90	19	294	258	36
Marketing margin	17	38	(21)	97	70	27
Unrealized losses on commodity risk management activities	(26)	(56)	30	(26)	(2)	(24)
Total segment margin	$634	$483	$ 151	$1,821	$1,558	$ 263

Segment Adjusted EBITDA. For the three months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $76 million in transportation margin due to a $63 million increase resulting from higher producer volumes from the Permian region on ETP's Texas NGL pipelines, an $11 million increase due to higher throughput volumes on Mariner West driven by end user facility constraints in the prior period, an $8 million increase due to higher throughput volumes from the Eagle Ford and Barnett regions, a $3 million increase due to higher throughput volumes in ETP's Northeast refined products system and a $3 million increase due to higher throughput volumes on Mariner South and Mariner East 1 NGL systems. These increases were partially offset by a $7 million decrease resulting from the timing of deficiency revenue recognition and a $5 million decrease from lower volumes from the Southeast Texas region;
- an increase of $47 million in fractionation and refinery services margin due to a $40 million increase resulting from the commissioning of ETP's fifth fractionator in July 2018 and higher NGL volumes from the Permian region feeding ETP's Mont Belvieu fractionation facility, a $4 million increase from Mariner South as more cargoes were loaded due to increased demand for export and a $3 million increase from blending gains as a result of improved market pricing; and
- an increase of $19 million in terminal services margin due to a $9 million increase resulting from a change in the classification of certain customer reimbursements previously recorded in operating expenses, a $6 million increase at ETP's Nederland terminal due to increased demand for propane exports and a $6 million increase due to higher throughput at ETP's Marcus Hook Industrial Complex. These increases were partially offset by a $2 million decrease due to reduced rental fees at ETP's Eagle Point facility; partially offset by
- an increase of $62 million in operating expenses due to increases of $25 million from higher throughput on ETP's fractionator, pipeline and terminal assets and the commissioning of ETP's fifth fractionator in July 2018, $10 million due to a legal settlement in the prior period, $9 million resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018, $7 million due to the timing of maintenance projects and higher overhead allocations, $6 million due to environmental reserves and $5 million due to ad valorem tax expense; and
- a decrease of $21 million in marketing margin primarily due to a $13 million decrease in optimization gains from ETP's Mont Belvieu marketing activities, a $4 million decrease from sales of propane and other products at ETP's Marcus Hook Industrial Complex and a $2 million decrease from ETP's butane blending operations resulting from a decrease in blending volumes.

Segment Adjusted EBITDA. For the nine months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $158 million in transportation margin due to a $141 million increase resulting from higher producer volumes from the Permian region on ETP's Texas NGL pipelines, a $22 million increase due to higher throughput volumes on Mariner West driven by end user facility constraints in the prior period, an $11 million increase resulting from a reclassification between ETP's transportation and fractionation margins in the second quarter of 2018, a $4 million increase due to higher throughput volumes from the Barnett region, a $4 million increase due to higher throughput volumes from ETP's Northeast and Southwest refined product systems and a $4 million increase due to higher throughput volumes on Mariner South due to system downtime in the prior period. These increases were partially offset by a $16 million decrease resulting from lower throughput on Mariner

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East 1 due to system downtime in 2018, a $10 million decrease due to lower transported volumes from the Southeast Texas region and a $2 million decrease resulting from the timing of deficiency revenue recognition;

- an increase of $72 million in fractionation and refinery services margin due to a $63 million increase resulting from the commissioning of ETP's fifth fractionator in July 2018 and higher NGL volumes from the Permian region feeding ETP's Mont Belvieu fractionation facility, a $12 million increase from blending gains as a result of improved market pricing and an $8 million increase as more cargoes were loaded at ETP's Mariner South export facility. These increases were partially offset by an $11 million decrease resulting from a reclassification between ETP's transportation and fractionation margins;
- an increase of $36 million in terminal services margin due to a $25 million increase resulting from a change in the classification of certain customer reimbursements previously recorded in operating expenses, a $13 million increase at ETP's Nederland terminal due to increased demand for propane exports and a $2 million increase due to favorable activity at ETP's Marcus Hook Industrial Complex. These increases were partially offset by a $3 million decrease due to reduced rental fees at ETP's Eagle Point facility and a $1 million decrease from ETP's marketing terminal volumes primarily due to the sale of one of ETP's terminals in April 2017;
- an increase of $27 million in marketing margin primarily due to a $17 million increase from ETP's butane blending operations and an $11 million increase from sales of domestic propane and other products at ETP's Marcus Hook Industrial Complex due to more favorable market prices; and
- an increase of $9 million in Adjusted EBITDA related to unconsolidated affiliates due to improved contributions from ETP's unconsolidated refined products joint venture interests; partially offset by
- an increase of $90 million in operating expenses primarily due to increases of $44 million from higher throughput on ETP's fractionator, pipeline and terminal assets and the commissioning of ETP's fifth fractionator in July 2018, $25 million resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018, $10 million due to a legal settlement in the prior period, $10 million due to environmental reserves and $4 million due to the timing of maintenance projects and higher overhead allocations; and
- a decrease of $6 million in storage margin primarily due to a $15 million decrease from the expiration and amendments to various NGL and refined products storage contracts, partially offset by an increase from throughput pipeline fees collected at ETP's Mont Belvieu storage terminal.

Crude Oil Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Crude transportation volumes (MBbls/d)	4,276	3,773	503	4,119	3,425	694
Crude terminals volumes (MBbls/d)	2,134	1,923	211	2,060	1,884	176
Revenues	$4,438	$2,725	$1,713	$12,986	$7,765	$5,221
Cost of products sold	3,494	2,177	1,317	11,032	6,571	4,461
Segment margin	944	548	396	1,954	1,194	760
Unrealized (gains) losses on commodity risk management activities	(118)	(1)	(117)	187	(3)	190
Operating expenses, excluding non-cash compensation expense	(126)	(119)	(7)	(397)	(305)	(92)
Selling, general and administrative expenses, excluding non-cash compensation expense	(22)	(13)	(9)	(64)	(62)	(2)
Adjusted EBITDA related to unconsolidated affiliates	4	5	(1)	14	11	3
Segment Adjusted EBITDA	$682	$420	$262	$1,694	$835	$859

Volumes. For the three and nine months ended September 30, 2018 crude transportation volumes increased due to placing the Bakken pipeline in service in June 2017 as well as higher throughput on existing pipelines due to increased production in West Texas. For the three and nine months ended September 30, 2018 crude terminal volumes benefited from an increase in barrels delivered to ETP's Nederland crude terminal from the Bakken pipeline and from increased West Texas production.

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Segment Adjusted EBITDA. For the three months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $279 million in segment margin (excluding unrealized losses on commodity risk management activities) due to the following: a $131 million increase resulting from higher throughput, primarily from ETP's Bakken pipeline and from Permian producers on existing pipeline assets, as well as a $30 million increase resulting primarily from placing ETP's Permian Express 3 pipeline in service in the fourth quarter of 2017; a $108 million increase (excluding a net change of $117 million in unrealized gains and losses) from ETP's crude oil acquisition and marketing business primarily resulting from more favorable market price differentials between the West Texas and Gulf Coast markets; and a $10 million increase from higher throughput and ship loading fees at ETP's Nederland terminal; partially offset by
- an increase of $9 million in selling, general and administrative expenses primarily due to increases of $4 million in overhead allocations, $2 million in employee costs and $2 million in insurance costs; and
- an increase of $7 million in operating expenses due to a $5 million increase due to higher throughput related expenses on existing assets and a $2 million increase from placing ETP's Permian Express 3 pipeline in service in the fourth quarter of 2017.

Segment Adjusted EBITDA. For the nine months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $950 million in segment margin (excluding unrealized losses on commodity risk management activities) primarily due to the following: a $541 million increase resulting primarily from placing ETP's Bakken pipeline in service in the second quarter of 2017; a $86 million increase resulting from higher throughput, primarily from Permian producers, on existing pipeline assets; a $295 million increase (excluding a net change of $190 million in unrealized gains and losses) from ETP's crude oil acquisition and marketing business primarily resulting from more favorable market price differentials between the West Texas and Gulf Coast markets; and a $25 million increase primarily from higher throughput and ship loading fees at ETP's Nederland terminal; and
- an increase of $3 million in Adjusted EBITDA related to unconsolidated affiliates due to increased jet fuel sales from ETP's joint ventures; partially offset by
- an increase of $92 million in operating expenses due to a $37 million increase primarily resulting from placing ETP's Bakken pipeline in service in the second quarter of 2017; a $36 million increase to throughput related costs on existing assets; a $19 million increase resulting from the addition of certain joint venture transportation assets in the second quarter of 2017; a $7 million increase in overhead allocations; and a $4 million increase from ad valorem taxes; partially offset by an $11 million decrease in insurance and environmental related expenses.

All Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Revenues	$525	$683	$(158)	$1,598	$2,249	$(651)
Cost of products sold	500	571	(71)	1,421	1,959	(538)
Segment margin	25	112	(87)	177	290	(113)
Unrealized (gains) losses on commodity risk management activities	7	3	4	9	(14)	23
Operating expenses, excluding non-cash compensation expense	(9)	(34)	25	(50)	(86)	36
Selling, general and administrative expenses, excluding non-cash compensation expense	(26)	(34)	8	(63)	(82)	19
Adjusted EBITDA related to unconsolidated affiliates	80	88	(8)	168	244	(76)

Other and eliminations	1	(2)	3	1	11	(10)
Segment Adjusted EBITDA	$78	$133	$(55)	$242	$363	$(121)

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Amounts reflected in ETP's all other segment primarily include:

- ETP's equity method investment in limited partnership units of Sunoco LP consisting of 26.2 million and 43.5 million Sunoco LP common units, representing 31.8% and 43.7% of Sunoco LP's total outstanding common units as of September 30, 2018 and September 30, 2017, respectively. The results above reflect Sunoco LP's repurchase of 17,286,859 Sunoco LP common units owned by ETP in February 2018; however, the results above do not reflect ETE's contribution of limited partner and general partner interests in Sunoco LP to ETP in connection with the ETE-ETP Merger in October 2018. For periods subsequent to the ETE-ETP Merger, ETP will reflect Sunoco LP as a consolidated subsidiary;
- ETP's natural gas marketing and compression operations. Subsequent to ETP's contribution of CDM to USAC in April 2018, ETP's all other segment includes ETP's equity method investment in USAC consisting of 19.2 million USAC common units and 6.4 million USAC Class B Units, together representing 26.6% of the limited partner interests. The results above do not reflect ETE's contribution of limited partner and general partner interests in USAC to ETP in connection with the ETE-ETP Merger in October 2018. For periods subsequent to the ETE-ETP Merger, ETP will reflect USAC as a consolidated subsidiary;
- a non-controlling interest in PES. Prior to PES's reorganization in August 2018, ETP's 33% interest in PES was reflected as an unconsolidated affiliate; subsequent the August 2018 reorganization, ETP holds an approximately 8% interest in PES and no longer reflects PES as an affiliate; and
- ETP's investment in coal handling facilities.

Segment Adjusted EBITDA. For the three months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's all other segment decreased due to the net impacts of the following:

- a decrease of $16 million in Adjusted EBITDA related to unconsolidated affiliates from ETP's investment in Sunoco LP resulting from ETP's lower ownership in Sunoco LP and lower operating results of Sunoco LP due to the sale of the majority of its retail assets in January 2018;
- a decrease of $12 million due to ETP's contribution of CDM to USAC in April 2018, which decrease reflects the impact of deconsolidating CDM, partially offset by an increase in Adjusted EBITDA related to unconsolidated affiliates due to the equity method investment in USAC held by ETP subsequent to the CDM contribution;
- a decrease of $12 million in Adjusted EBITDA related to unconsolidated affiliates from ETP's investment in PES primarily due to ETP's lower ownership in PES subsequent to its reorganization, which resulted in PES no longer being reflected as an affiliate beginning in the third quarter of 2018;
- an increase of $7 million in general and administrative expenses from higher professional expenses;
- a decrease of $6 million due to losses from commodity trading and risk management activities; and
- a decrease of $3 million primarily due to lower margin from ETP's compression equipment business.

Segment Adjusted EBITDA. For the nine months ended September 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to ETP's all other segment decreased due to the net impacts of the following:

- a decrease of $85 million in Adjusted EBITDA related to unconsolidated affiliates from ETP's investment in Sunoco LP resulting from ETP's lower ownership in Sunoco LP and lower operating results of Sunoco LP due to the sale of the majority of its retail assets in January 2018;
- a decrease of $31 million in Adjusted EBITDA related to unconsolidated affiliates from ETP's investment in PES primarily due to ETP's lower ownership in PES subsequent to its reorganization, which resulted in PES no longer being reflected as an affiliate beginning in the third quarter of 2018, as well as lower Adjusted EBITDA prior to August 2018; and
- a decrease of $21 million due to ETP's contribution of CDM to USAC in April 2018, which decrease reflects the impact of deconsolidating CDM, partially offset by an increase in Adjusted EBITDA related to unconsolidated affiliates due to the equity method investment in USAC held by ETP subsequent to the CDM Contribution; partially offset by
- an increase of $10 million in Adjusted EBITDA primarily due to lower transport fees of $6 million resulting from the expiration of a capacity commitment on ETP's Trunkline pipeline and a $7 million decrease in losses from the mark-to-market of physical system gas, offset by lower optimization gains on residue gas sales;
-

- an increase of $6 million due to increased margin from ETP’s compression equipment business as several large projects were completed in June 2018; and
- an increase of $4 million due to an equipment lease buyout in August 2017, partially offset by lower margin from depressed gas prices in West Texas.

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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.

We currently expect capital expenditures in 2018 to be within the following ranges (excluding capital expenditures related to the businesses contributed to ETP in connection with the ETE-ETP Merger in October 2018):

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$275	$300	$30	$35
Interstate transportation and storage [(1)]	675	700	115	120
Midstream	975	1,025	130	135
NGL and refined products transportation and services	2,100	2,150	60	70
Crude oil transportation and services [(1)]	425	450	90	100
All other (including eliminations)	50	75	60	65
Total capital expenditures	$4,500	$4,700	$485	$525

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

For 2019, we expect to spend approximately $5 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 net changes in operating assets and liabilities (net of effects of acquisitions and deconsolidations). 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 of assets, while changes in non-cash compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of derivative assets and liabilities, the timing of accounts receivable collection, the timing of payments on accounts payable, the timing of purchase and sales of inventories and the timing of advances and deposits received from customers.

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Nine months ended September 30, 2018 compared to nine months ended September 30, 2017. Cash provided by operating activities during 2018 was $5.10 billion compared to $3.34 billion for 2017 and net income was $2.84 billion and $1.40 billion for 2018 and 2017, respectively. The difference between net income and cash provided by operating activities for the nine months ended September 30, 2018 primarily consisted of net changes in operating assets and liabilities (net of effects of acquisitions and deconsolidations) of $451 million and other non-cash items totaling $1.51 billion.

The non-cash activity in 2018 and 2017 consisted primarily of depreciation, depletion and amortization of $1.83 billion and $1.71 billion, respectively, and non-cash compensation expense of $61 million and $57 million, respectively. Unconsolidated affiliate activity in 2018 and 2017 consisted of equity in earnings of $147 million and $139 million, respectively, and distributions received of $328 million and $319 million, respectively. Non-cash activity in 2018 also included a gain on the sale of Sunoco LP units of $172 million and a loss on the deconsolidation of CDM of $86 million.

Cash paid for interest, net of interest capitalized, was $996 million and $1.01 billion for the nine months ended September 30, 2018 and 2017, respectively.

Capitalized interest was $221 million and $211 million for the nine months ended September 30, 2018 and 2017, 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, 2018 compared to nine months ended September 30, 2017. Cash used in investing activities during 2018 was $3.07 billion compared to $4.69 billion in 2017. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2018 were $4.87 billion compared to $6.06 billion for 2017. Additional detail related to our capital expenditures is provided in the table below. During 2018, we received $1.23 billion in cash related to the CDM Contribution and $540 million in cash related to the Sunoco LP common unit repurchase. During 2017, we received $2.00 billion in cash related to the Bakken equity sale to MarEn Bakken Company LLC, paid $280 million in cash for the acquisition of PennTex noncontrolling interest and paid $264 million in cash for all other acquisitions.

The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the nine months ended September 30, 2018:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$233	$ 37	$270
Interstate transportation and storage	470	73	543
Midstream	731	113	844
NGL and refined products transportation and services	1,494	44	1,538
Crude oil transportation and services	333	33	366
All other (including eliminations)	43	42	85
Total capital expenditures	$3,304	$ 342	$3,646

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, 2018 compared to nine months ended September 30, 2017. Cash used in financing activities during 2018 was $1.96 billion compared to provided by financing activities of $1.37 billion for 2017. In 2018 and 2017, we received net proceeds from ETP common unit offerings of $58 million and $2.16 billion, respectively. In 2018, we received $867 million from preferred unit offerings. During 2018, we had a net increase in our debt level of $410 million compared to a net increase of $1.24 billion for 2017. We have paid distributions of

$3.14 billion to ETP's unitholders in 2018 compared to $2.54 billion in 2017. We have also paid distributions of $536 million to noncontrolling interests in 2018 compared to $306 million in 2017. In addition, we have received capital contributions of $438 million in cash from noncontrolling interests in 2018 compared

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to $919 million in 2017. During 2018, we also repurchased ETP common units for cash of $24 million and incurred debt issuance costs of $42 million. During 2017, we also repurchased our outstanding Legacy ETP Preferred Units for cash of $53 million and incurred debt issuance costs of $50 million.

Off-Balance Sheet Arrangements

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 certain of Sunoco LP's senior notes and $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 ("ETC M-A").

On January 23, 2018, Sunoco LP redeemed the previously guaranteed senior notes, repaid and terminated the term loan and issued the following notes (the "Sunoco LP Notes") for which ETC M-A has also guaranteed collection with respect to the payment of principal amounts:

- $1.00 billion aggregate principal amount of 4.875% senior notes due 2023;
- $800 million aggregate principal amount of 5.50% senior notes due 2026; and
- $400 million aggregate principal amount of 5.875% senior notes due 2028.

Under the guarantee of collection, ETC M-A would have the obligation to pay the principal of each series of notes once all remedies, including in the context of bankruptcy proceedings, have first been fully exhausted against Sunoco LP with respect to such payment obligation, and holders of the notes are still owed amounts in respect of the principal of such notes. ETC M-A will not otherwise be subject to the covenants of the indenture governing the notes.

In connection with the issuance of the Sunoco LP Notes, Sunoco LP entered into a registration rights agreement with the initial purchasers pursuant to which Sunoco LP agreed to complete an offer to exchange the Sunoco LP Notes for an issue of registered notes with terms substantively identical to each series of Sunoco LP Notes and evidencing the same indebtedness as the Sunoco LP Notes on or before January 23, 2019.

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Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2018	December 31, 2017
ETP Senior Notes [1]	$ 28,755	$ 27,005
Transwestern Senior Notes	575	575
Panhandle Senior Notes	386	785
Credit facilities and commercial paper:		
ETP $5.00 billion Revolving Credit Facility due December 2023 [2]	1,780	2,292
ETP $1.00 billion 364-Day Credit Facility due November 2019	—	50
Bakken Project $2.50 billion Credit Facility due August 2019	2,500	2,500
Other long-term debt	4	5
Unamortized premiums, net of discounts and fair value adjustments	35	61
Deferred debt issuance costs	(188)	(179)
Total debt	33,847	33,094
Less: current maturities of long-term debt	2,649	407
Long-term debt, less current maturities	$ 31,198	$ 32,687

(1) Includes $400 million aggregate principal amount of 9.70% senior notes due March 15, 2019 and $450 million aggregate principal amount of 9.00% senior notes due April 15, 2019 that were classified as long-term as of September 30, 2018 as management has the intent and ability to refinance the borrowings on a long-term basis.

(2) Includes $1.57 billion and $2.01 billion of commercial paper outstanding at September 30, 2018 and December 31, 2017, respectively.

ETP Senior Notes Offering and Redemption

In June 2018, ETP issued the following senior notes:

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

The senior notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the senior notes. The principal on the senior notes is payable upon maturity and interest is paid semi-annually.

The senior notes rank equally in right of payment with ETP's existing and future senior debt, and senior in right of payment to any future subordinated debt ETP may incur. The notes of each series will initially be fully and unconditionally guaranteed by our subsidiary, Sunoco Logistics Partners Operations L.P., on a senior unsecured basis so long as it guarantees any of our other long-term debt. The guarantee for each series of notes ranks equally in right of payment with all of the existing and future senior debt of Sunoco Logistics Partners Operations L.P., including its senior notes.

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

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

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

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Credit Facilities and Commercial Paper

ETP Five-Year Credit Facility

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

As of September 30, 2018, the ETP Five-Year Credit Facility had $1.78 billion outstanding, of which $1.57 billion was commercial paper. The amount available for future borrowings was $2.06 billion after taking into account letters of credit of $163 million, but before taking into account the additional capacity from the October 19, 2018 amendment. The weighted average interest rate on the total amount outstanding as of September 30, 2018 was 3.00%.

ETP 364-Day Facility

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

Bakken Credit Facility

In August 2016, ETP and Phillips 66 completed project-level financing of the Bakken pipeline. The $2.50 billion credit facility matures in August 2019 (the "Bakken Credit Facility"). As of September 30, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings, all of which has been reflected in current maturities of long-term debt on the Partnership's consolidated balance sheet included in "Item 1. Financial Statements." The weighted average interest rate on the total amount outstanding as of September 30, 2018 was 3.85%.

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, 2018.

CASH DISTRIBUTIONS

Distributions on common units declared and paid by the Partnership subsequent to December 31, 2017 but prior to the closing of the ETE-ETP Merger as discussed in Note 1 of the Partnership's consolidated financial statements included in "Item 1. Financial Statements," were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017	February 8, 2018	February 14, 2018	$0.5650
March 31, 2018	May 7, 2018	May 15, 2018	0.5650
June 30, 2018	August 6, 2018	August 14, 2018	0.5650

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Distributions on ETP's preferred units declared and/or paid by the Partnership subsequent to December 31, 2017 were as follows:

Period Ended	Record Date	Payment Date	Rate
Series A Preferred Units			
December 31, 2017	February 1, 2018	February 15, 2018	$15.451
June 30, 2018	August 1, 2018	August 15, 2018	31.250
Series B Preferred Units			
December 31, 2017	February 1, 2018	February 15, 2018	$16.378
June 30, 2018	August 1, 2018	August 15, 2018	33.125
Series C Preferred Units			
June 30, 2018	August 1, 2018	August 15, 2018	$0.5634
September 30, 2018	November 1, 2018	November 15, 2018	0.4609
Series D Preferred Units			
September 30, 2018	November 1, 2018	November 15, 2018	$0.5931

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules, and we believe the proper implementation and consistent application of the accounting rules are critical. We describe our significant accounting policies in Note 2 to our consolidated financial statements in the Partnership's Annual Report on Form 10-K filed with the SEC on February 23, 2018. See Note 1 in "Item 1. Financial Statements" for information regarding recent changes to the Partnership's critical accounting policies related to revenue recognition.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1 in "Item 1. Financial Statements" included in this Quarterly Report for information regarding recent accounting pronouncements.

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 included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on February 23, 2018, 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, 2017. Since December 31, 2017, there have been no material changes to our primary market risk exposures or how those exposures are managed.

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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. Dollar amounts are presented in millions.

	September 30, 2018			December 31, 2017		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (BBtu):						
Fixed Swaps/Futures	358	$ —	$ —	1,078	$ —	$ —
Basis Swaps IFERC/NYMEX [1]	69,685	8	1	48,510	2	1
Options – Puts	(17,273)	—	—	13,000	—	—
Power (Megawatt):						
Forwards	429,720	6	—	435,960	1	1
Futures	309,123	(1)	1	(25,760)	—	—
Options – Puts	157,435	1	—	(153,600)	—	1
Options – Calls	321,240	—	—	137,600	—	—
Crude (MBbls) – Futures	—	—	—	—	1	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(7,705)	(45)	14	4,650	(13)	4
Swing Swaps IFERC	69,145	—	2	87,253	(2)	1
Fixed Swaps/Futures	(1,784)	1	1	(4,700)	(1)	2
Forward Physical Contracts	(54,151)	5	—	(145,105)	6	41
NGL (MBbls) – Forwards/Swaps	(4,997)	(45)	20	(2,493)	5	16
Crude (MBbls) – Forwards/Swaps	35,280	(190)	152	9,172	(4)	9
Refined Products (MBbls) – Futures	(1,521)	(5)	9	(3,783)	(25)	4
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(21,475)	(4)	—	(39,770)	(2)	—
Fixed Swaps/Futures	(21,475)	(2)	7	(39,770)	14	11

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

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the 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, 2018, we had $4.88 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $49 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

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our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

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

Term	Type[1]	Notional Amount Outstanding September 30, 2018	Notional Amount Outstanding December 31, 2017
July 2018[2]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	$ —	$ 300
July 2019[2]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	400	300
July 2020[2]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	400
July 2021[2]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	400	—
December 2018	Pay a floating rate 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 $239 million as of September 30, 2018. 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 $4 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, 2018 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

There have been no 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, 2018 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Annual Report on Form 10-K filed with the SEC on February 23, 2018 and Note 10 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Operating, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2018.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the environmental proceedings listed below were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report governmental proceedings if we reasonably believe that such proceedings will result in monetary sanctions in excess of $100,000. Pursuant to the instructions to Form 10-Q, matters disclosed in this Part II, Item 1 include any reportable legal proceeding (i) that has been terminated during the period covered by this report, (ii) that became a reportable event during the period covered by this report, or (iii) for which there has been a material development during the period covered by this report.

On January 18, 2018, PHMSA issued a Notice of Probable Violation and a Proposed Compliance Order in connection with alleged violations on our Eastern Area refined products and crude oil pipeline system in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey and Delaware. We have paid the civil penalties of $163,700. The case was closed in July 2018.

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

On June 29, 2018, Luminant Energy Company, LLC ("Luminant") filed informal and formal complaints against Energy Transfer Fuel, LP ("ETF"), with the Railroad Commission of Texas ("TRRC"). Luminant's complaints allege that absent an agreement between Luminant and ETF regarding the rate to be charged for bundled transportation and storage service, ETF must file a statement of intent with the TRRC to change the rate charged to Luminant for this service. ETF filed a response to Luminant's informal complaint on July 16, 2018. ETF filed a response and motion to dismiss Luminant's formal complaint on July 23, 2018. On August 16, 2018, a Commission Administrative Law Judge ("ALJ") granted ETF's motion to dismiss Luminant's claims relating to unlawful abandonment and discrimination. The ALJ denied ETF's motion to dismiss Luminant's claims regarding the rate charged for service and the procedural process applicable to rate changes. Luminant appealed the decision. The appeal was denied by operation of law on October 1, 2018. A mediation of the informal complaint filed by Luminant was held on September 17, 2018 and no decision was reached. The parties continue to negotiate in good faith.

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

On September 17, 2018, William D. Warner ("Plaintiff"), a purported ETP unitholder, filed a putative class action asserting violations of various provisions of the Securities Exchange Act of 1934 and various rules promulgated thereunder in connection with the ETE-ETP Merger against ETP, Kelcy L. Warren, Michael K. Grimm, Marshall S. McCrea, Matthew S. Ramsey, David K. Skidmore, and W. Brett Smith ("Defendants"). Plaintiff specifically alleges that the Form S-4 Registration Statement issued in connection with the ETE-ETP Merger omits and/or misrepresents material information. Defendants believe the allegations have no merit and intend to defend vigorously against them. On October 26, 2018, Plaintiff and Defendants entered into a stipulation staying Defendants' response deadlines until the designation of a lead plaintiff/lead counsel structure in accordance with the Private Securities Litigation Reform Act.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors described in Part I, Item 1A in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on February 23, 2018 or from the risk factors described in "Part II - Item 1A. Risk Factors" in the Partnership's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 filed with the SEC on May 10, 2018 and "Part II - Item 1A. Risk Factors" in the Partnership's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 filed on August 9, 2018.

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ITEM 6. EXHIBITS

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

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of August 1, 2018, by and among LE GP, LLC, Energy Transfer Equity, L.P., Streamline Merger Sub, LLC, Energy Transfer Partners, L.L.C. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 2.1 to the Form 8-K filed August 3, 2018)
3.1	Certificate of Limited Partnership of Sunoco Logistics Partners L.P. (incorporated by reference to Exhibit 3.1 of Form S-1 Registration Statement 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 to the Current Report on Form 8-K 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 to the Current Report on Form 8-K filed April 28, 2017)
3.4	Certificate of Merger of Streamline Merger Sub, LLC, with and into Energy Transfer Partners, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed October 19, 2018)
3.5	Fifth Amended and Restated Agreement of Limited Partnership of Energy Transfer Operating, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed October 19, 2018)
10.1***	Amended and Restated Energy Transfer Partners, L.L.C. Annual Bonus Plan (incorporated by reference to Exhibit 10.3 of Form 10-Q, File No. 1-31219, filed August 9, 2018)
10.2	Amendment No. 1 to Five-Year Credit Agreement, Joinder and Increase and Extension Agreement, dated as of October 19, 2018, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P., and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 19, 2018)
10.3	Amendment No. 1 to 364-Day Credit Agreement, Joinder and Increase and Extension Agreement, dated as of October 19, 2018, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P., and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed October 19, 2018)
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.

*** Denotes a management contract or compensatory plan or arrangement.

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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 OPERATING, L.P.	
		By:	Energy Transfer Partners GP, L.P., its general partner
		By:	Energy Transfer Partners, L.L.C., its general partner
Date:	November 8, 2018	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)

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