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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 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 PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

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

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

At May 4, 2018, the registrant had 1,165,133,105 Common Units outstanding.

FORM 10-Q

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (the "Partnership" or "ETP") in periodic press releases and some oral statements of the Partnership's officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "expect," "continue," "estimate," "goal," "forecast," "may," "will" or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management's control. For additional discussion of risks, uncertainties and assumptions, see "Part I – Item 1A. Risk Factors" in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017 filed with the Securities and Exchange Commission on February 23, 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)
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
BBtu	billion British thermal units
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
CDM E&T	CDM Environmental & Technical Services LLC
Citrus	Citrus, LLC
CrossCountry	CrossCountry Energy, 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
ETE	Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC for the periods presented herein
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. and its wholly-owned subsidiary, Regency Intrastate Gas LP

IDRs	incentive distribution rights
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
PCBs	polychlorinated biphenyls
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.
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
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.

PART I – FINANCIAL INFORMATION

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

	March 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 446	$ 306
Accounts receivable, net	3,123	3,946
Accounts receivable from related companies	340	318
Inventories	1,421	1,589
Income taxes receivable	166	135
Derivative assets	23	24
Other current assets	229	210
Total current assets	5,748	6,528
Property, plant and equipment	69,164	67,699
Accumulated depreciation and depletion	(9,791)	(9,262)
	59,373	58,437
Advances to and investments in unconsolidated affiliates	3,258	3,816
Other non-current assets, net	758	758
Intangible assets, net	5,243	5,311
Goodwill	3,115	3,115
Total assets	$ 77,495	$ 77,965

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

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

	March 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,288	$ 4,126
Accounts payable to related companies	244	209
Derivative liabilities	147	109
Accrued and other current liabilities	2,140	2,143
Current maturities of long-term debt	404	407
Total current liabilities	6,223	6,994
Long-term debt, less current maturities	33,109	32,687
Non-current derivative liabilities	97	145
Deferred income taxes	2,860	2,883
Other non-current liabilities	1,100	1,084
Commitments and contingencies		
Redeemable noncontrolling interests	21	21
Equity:		
Series A Preferred Unitholders	943	944
Series B Preferred Unitholders	546	547
Common Unitholders	26,143	26,531
General Partner	365	244
Accumulated other comprehensive income	2	3
Total partners’ capital	27,999	28,269
Noncontrolling interest	6,086	5,882
Total equity	34,085	34,151
Total liabilities and equity	$ 77,495	$ 77,965

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

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

	Three Months Ended March 31,	
	2018	2017*
REVENUES:		
Natural gas sales	$ 1,062	$ 1,012
NGL sales	2,030	1,547
Crude sales	3,254	2,542
Gathering, transportation and other fees	1,397	1,024
Refined product sales	439	471
Other	98	299
Total revenues	8,280	6,895
COSTS AND EXPENSES:		
Cost of products sold	5,988	5,050
Operating expenses	604	492
Depreciation, depletion and amortization	603	560
Selling, general and administrative	112	110
Total costs and expenses	7,307	6,212
OPERATING INCOME	973	683
OTHER INCOME (EXPENSE):		
Interest expense, net	(346)	(332)
Equity in earnings (losses) of unconsolidated affiliates	(72)	73
Gain on Sunoco LP common unit repurchase	172	—
Gains on interest rate derivatives	52	5
Other, net	60	19
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	839	448
Income tax expense (benefit)	(40)	55
NET INCOME	879	393
Less: Net income attributable to noncontrolling interest	164	62
NET INCOME ATTRIBUTABLE TO PARTNERS	715	331
General Partner’s interest in net income	402	206
Series A Preferred Unitholders’ interest in net income	15	—
Series B Preferred Unitholders’ interest in net income	9	—
Class H Unitholder’s interest in net income	—	93
Common Unitholders’ interest in net income	$ 289	$ 32
NET INCOME PER COMMON UNIT:		
Basic	$ 0.24	$ 0.03
Diluted	$ 0.24	$ 0.03

* As adjusted. See Note 1.

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

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

	Three Months Ended March 31,	
	2018	2017*
Net income	$ 879	$ 393
Other comprehensive income (loss), net of tax:		
Change in value of available-for-sale securities	(2)	2
Actuarial loss relating to pension and other postretirement benefit plans	(2)	(2)
Change in other comprehensive income from unconsolidated affiliates	5	—
	1	—
Comprehensive income	880	393
Less: Comprehensive income attributable to noncontrolling interest	164	62
Comprehensive income attributable to partners	$ 716	$ 331

* As adjusted. See Note 1.

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE THREE MONTHS ENDED MARCH 31, 2018
(Dollars in millions)
(unaudited)

	Series A Preferred Units	Series B Preferred Units	Common Units	General Partner	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
Balance, December 31, 2017	$ 944	$ 547	$ 26,531	$ 244	$ 3	$ 5,882	$ 34,151
Distributions to partners	(15)	(9)	(657)	(264)	—	—	(945)
Distributions to noncontrolling interest	—	—	—	—	—	(183)	(183)
Units issued for cash	—	—	20	—	—	—	20
Capital contributions from noncontrolling interest	—	—	—	—	—	229	229
Repurchases of common units	—	—	(24)	—	—	—	(24)
Other comprehensive income, net of tax	—	—	—	—	1	—	1
Other, net	(1)	(1)	(16)	(17)	(2)	(6)	(43)
Net income	15	9	289	402	—	164	879
Balance, March 31, 2018	$ 943	$ 546	$ 26,143	$ 365	$ 2	$ 6,086	$ 34,085

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

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017*
OPERATING ACTIVITIES		
Net income	$ 879	$ 393
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	603	560
Deferred income taxes	(40)	54
Non-cash compensation expense	20	23
Gain on Sunoco LP common unit repurchase	(172)	—
Distributions on unvested awards	(8)	(8)
Equity in (earnings) losses of unconsolidated affiliates	72	(73)
Distributions from unconsolidated affiliates	106	82
Other non-cash	(78)	(53)
Net change in operating assets and liabilities, net of effects of acquisitions	392	(46)
Net cash provided by operating activities	1,774	932
INVESTING ACTIVITIES		
Cash proceeds from Bakken Pipeline Transaction	—	2,000
Cash proceeds from Sunoco LP common unit repurchase	540	—
Cash paid for acquisition of PennTex noncontrolling interest	—	(280)
Cash paid for all other acquisitions	(4)	(38)
Capital expenditures, excluding allowance for equity funds used during construction	(1,718)	(1,384)
Contributions in aid of construction costs	20	6
Contributions to unconsolidated affiliates	(8)	(111)
Distributions from unconsolidated affiliates in excess of cumulative earnings	27	90
Other	—	(3)
Net cash (used in) provided by investing activities	(1,143)	280
FINANCING ACTIVITIES		
Proceeds from borrowings	3,959	6,366
Repayments of long-term debt	(3,545)	(7,216)
Cash received from (paid to) affiliate notes	2	(250)
Units issued for cash	20	826
Capital contributions from noncontrolling interest	229	106
Distributions to partners	(945)	(896)
Distributions to noncontrolling interest	(183)	(148)
Repurchases of common units	(24)	—
Redemption of Legacy ETP Preferred Units	—	(53)
Debt issuance costs	—	(19)
Other	(4)	3
Net cash used in financing activities	(491)	(1,281)
Increase (decrease) in cash and cash equivalents	140	(69)
Cash and cash equivalents, beginning of period	306	360
Cash and cash equivalents, end of period	$ 446	$ 291

* As adjusted. See Note 1.

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

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

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Energy Transfer Partners, L.P. ("ETP") is a consolidated subsidiary of ETE.

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

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

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

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, given that the legacy ETP inventory has been accounted for using the weighted-average cost method.

As a result of this change in accounting policy, prior periods have been retrospectively adjusted, as follows:

	Three Months Ended March 31, 2017		
	As Originally Reported*	Effect of Change	As Adjusted
Consolidated Statement of Operations and Comprehensive Income:			
Cost of products sold	$ 5,079	$ (29)	$ 5,050
Operating income	654	29	683
Income before income tax expense	419	29	448
Net income	364	29	393
Net income attributable to partners	324	7	331
Net income per common unit – basic	0.02	0.01	0.03
Net income per common unit – diluted	0.02	0.01	0.03
Comprehensive income	364	29	393
Comprehensive income attributable to partners	324	7	331
Consolidated Statements of Cash Flows:			
Net income	364	29	393
Inventory valuation adjustments	(2)	2	—
Net change in operating assets and liabilities (change in inventories)	(15)	(31)	(46)

* Amounts reflect certain reclassifications made to conform to the current year presentation.

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 increases in revenue (with offsetting increases 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.

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 March 31, 2018		
	As Reported	Balances Without Adoption of ASC 606	Effect of Change: Higher/(Lower)
Revenues:			
Natural gas sales	$ 1,062	$ 1,062	$ —
NGL sales	2,030	2,019	11
Crude sales	3,254	3,254	—
Gathering, transportation and other fees	1,397	1,584	(187)
Refined product sales	439	439	—
Other	98	98	—
Costs and expenses:			
Cost of products sold	5,988	6,175	(187)
Operating expenses	604	593	11

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 useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. 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 Topic 840. The Partnership expects to adopt ASU 2016-02 and elect the practical expedient under ASU 2018-01 in the first quarter of 2019 and is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

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 retained earnings at 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

CDM Contribution

On April 2, 2018, ETP contributed to USAC all of the issued and outstanding membership interests of CDM and CDM E&T for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 common units representing limited partner interests in USAC (“USAC Common Units”), (ii) 6,397,965 units of a newly authorized and established class of units representing limited partner interests in USAC (“Class B Units”) and (iii) $1.23 billion in cash, including customary closing adjustments (the “CDM Contribution”). The 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 Class B Units will not participate in distributions for the first four quarters following the closing date of April 2, 2018. Each 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.

Beginning April 2018, ETP’s consolidated financial statements will reflect an equity method investment in USAC. CDM and CDM E&T’s assets and liabilities have not been reflected as held for sale, nor have CDM and CDM E&T’s results been reflected as discontinued operations in these financial statements.

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.

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. In connection with this transaction, the Partnership recognized a gain of $172 million.

3. CASH AND CASH EQUIVALENTS

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

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

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

	Three Months Ended March 31,	
	2018	2017*
Accounts receivable	$ 817	$ (23)
Accounts receivable from related companies	122	(44)
Inventories	169	137
Other current assets	(48)	43
Other non-current assets, net	(3)	(18)
Accounts payable	(667)	(88)
Accounts payable to related companies	(111)	120
Accrued and other current liabilities	106	(139)
Other non-current liabilities	16	(2)
Derivative assets and liabilities, net	(9)	(32)
Net change in operating assets and liabilities, net of effects of acquisitions	$ 392	$ (46)

* As adjusted. See Note 1.

Non-cash investing and financing activities are as follows:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 1,010	$ 832
NON-CASH FINANCING ACTIVITIES:		
Contribution of property, plant and equipment from noncontrolling interest	$ —	$ 988

4. INVENTORIES

Inventories consisted of the following:

	March 31, 2018	December 31, 2017
Natural gas, NGLs, and refined products	$ 419	$ 733
Crude oil	701	551
Spare parts and other	301	305
Total inventories	$ 1,421	$ 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.

5. FAIR VALUE MEASURES

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations as of March 31, 2018 was $33.78 billion and $33.51 billion, respectively. As of December 31, 2017, the aggregate fair value and carrying amount of 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 three months ended March 31, 2018, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the gross fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of March 31, 2018 and December 31, 2017 based on inputs used to derive their fair values:

		Fair Value Measurements at March 31, 2018	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 35	$ 35	$ —
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	14	14	—
Forward Physical Contracts	7	—	7
Power:			
Forwards	78	—	78
Options – Puts	1	1	—
Options – Calls	1	1	—
Natural Gas Liquids – Forwards/Swaps	115	115	—
Total commodity derivatives	252	166	86
Other non-current assets	21	14	7
Total assets	$ 273	$ 180	$ 93
Liabilities:			
Interest rate derivatives	$ (167)	$ —	$ (167)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(81)	(81)	—
Swing Swaps IFERC	(1)	—	(1)
Fixed Swaps/Futures	(13)	(13)	—
Options – Calls	(1)	(1)	—
Forward Physical Contracts	(6)	—	(6)
Power – Forwards	(72)	—	(72)
Natural Gas Liquids – Forwards/Swaps	(169)	(169)	—
Refined Products – Futures	(3)	(3)	—
Total commodity derivatives	(346)	(267)	(79)
Total liabilities	$ (513)	$ (267)	$ (246)

	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 Swaps	8	—	8
Power – Forwards	23	—	23
Natural Gas Liquids – Forwards/Swaps	193	193	—
Crude – 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 Swaps	(2)	—	(2)
Power – Forwards	(22)	—	(22)
Natural Gas Liquids – Forwards/Swaps	(192)	(192)	—
Refined Products – Futures	(25)	(25)	—
Crude – Futures	(1)	(1)	—
Total commodity derivatives	(338)	(300)	(38)
Total liabilities	$ (557)	$ (300)	$ (257)

6. NET INCOME PER LIMITED PARTNER UNIT

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

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

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

	Three Months Ended March 31,	
	2018	2017*
Net income	$ 879	$ 393
Less: Income attributable to noncontrolling interest	164	62
Net income, net of noncontrolling interest	715	331
General Partner's interest in net income	402	206
Series A Preferred Unitholders' interest in net income	15	—
Series B Preferred Unitholders' interest in net income	9	—
Class H Unitholder's interest in net income	—	93
Common Unitholders' interest in net income	289	32
Additional earnings allocated to General Partner	(2)	(3)
Distributions on employee unit awards, net of allocation to General Partner	(8)	(7)
Net income available to Common Unitholders	$ 279	$ 22
Weighted average Common Units – basic	1,163.8	822.3
Basic net income per Common Unit	$ 0.24	$ 0.03
Dilutive effect of unvested employee unit awards	4.0	2.2
Weighted average Common Units – diluted	1,167.8	824.5
Diluted net income per Common Unit	$ 0.24	$ 0.03

* As adjusted. See Note 1.

7. DEBT OBLIGATIONS

Credit Facilities and Commercial Paper

ETP Five-Year Credit Facility

ETP's revolving credit facility (the "ETP Five-Year Credit Facility") allows for unsecured borrowings up to $4.00 billion and matures in December 2022. 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 March 31, 2018, the ETP Five-Year Credit Facility had $2.76 billion outstanding, of which $1.93 billion was commercial paper. The amount available for future borrowings was $1.09 billion after taking into account letters of credit of $155 million. The weighted average interest rate on the total amount outstanding as of March 31, 2018 was 2.92%.

ETP 364-Day Facility

ETP's 364-day term loan facility (the "ETP 364-Day Facility") allows for unsecured borrowings up to $1.00 billion and matures on November 30, 2018. As of March 31, 2018, the ETP 364-Day Facility had no outstanding borrowings.

Bakken Credit Facility

In August 2016, Energy Transfer Partners, L.P., Sunoco Logistics and Phillips 66 completed project-level financing of the Bakken Pipeline. The $2.50 billion credit facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects and matures in August 2019 (the "Bakken Credit Facility"). As of March 31, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings. The weighted average interest rate on the total amount outstanding as of March 31, 2018 was 3.31%.

Compliance with Our Covenants

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of March 31, 2018.

8. EQUITY

The changes in outstanding common units during the three months ended March 31, 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	1.1
Repurchases of common units in open-market transactions	(1.2)
Number of common units at March 31, 2018	1,164.0

Equity Distribution Program

During the three months ended March 31, 2018, there were no units issued under the Partnership's equity distribution agreements. As of March 31, 2018, $752 million of the Partnership's common units remained available to be issued under the Partnership's existing $1.00 billion equity distribution agreement.

Distribution Reinvestment Program

During the three months ended March 31, 2018, distributions of $20 million were reinvested under the distribution reinvestment plan.

Preferred Units

As of each of March 31, 2018 and December 31, 2017, the Partnership had 950,000 Series A Preferred Units and 550,000 Series B Preferred Units outstanding.

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 our 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.

Quarterly Distributions of Available Cash

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

Distributions on common units declared and/or paid by the Partnership subsequent to December 31, 2017 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

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

	Total Year
2018 (remainder)	$ 111
2019	128
Each year beyond 2019	33

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

			Distribution per Preferred Unit	
Quarter Ended	Record Date	Payment Date	Series A	Series B
December 31, 2017	February 1, 2018	February 15, 2018	$ 15.451	$ 16.378

Accumulated Other Comprehensive Income

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

	March 31, 2018	December 31, 2017
Available-for-sale securities [(1)]	$ 4	$ 8
Foreign currency translation adjustment	(5)	(5)
Actuarial loss related to pensions and other postretirement benefits	(7)	(5)
Investments in unconsolidated affiliates, net	10	5
Total AOCI, net of tax	$ 2	$ 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 months ended March 31, 2018 the Partnership's income tax benefit also reflected a $67 million deferred benefit adjustment as the result of a state statutory rate reduction.

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 (i) $800 million principal amount of 6.375% senior notes due 2023 issued by Sunoco LP, (ii) $800 million principal amount of 6.25% senior notes due 2021 issued by Sunoco LP and (iii) $2.035 billion aggregate principal for Sunoco LP's term loan due 2019. In December 2016, Retail Holdings contributed its interests in Sunoco LP, along with the assignment of the guarantee of Sunoco LP's senior notes, to its subsidiary, ETC M-A Acquisition LLC ("ETC M-A").

On January 23, 2018, Sunoco LP redeemed the previously guaranteed senior notes and issued the following 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.

FERC Audit

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

Commitments

In the normal course of 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.

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 March 31,	
	2018	2017
Rental expense	$ 25	$ 20

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 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 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 Tribes 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 Tribe.

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. Following the completion of the remand process by the USACE, the Court will make a determination regarding the three discrete issues covered by the remand order.

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 block 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 April 18, 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.

Sunoco, Inc. and Sunoco, Inc. (R&M) have reached a settlement with the State of New Jersey. The Court approved the Judicial Consent Order on December 5, 2017. On April 5, 2018, the Court entered an Order dismissing the matter with prejudice.

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. On March 6, 2018, Defendants filed their Answer to Plaintiff's Verified Amended Class Action Complaint.

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 Defendants predict the amount of time and expense that will be required to resolve the Regency Merger Litigation. Defendants believe the Regency Merger Litigation is without merit and intend to vigorously defend against it and any others that may be filed in connection with the Regency Merger.

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

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

Bayou Bridge

On January 11, 2018, environmental groups and a trade association filed suit against the United States Army Corps of Engineers (the "Corps") in the United States District Court for the Middle District of Louisiana. Plaintiffs allege that the Corps' 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 Corps corrects alleged deficiencies in its decision-making process. ETP, through its subsidiary Bayou Bridge Pipeline, LLC ("Bayou Bridge"), intervened on January 26. On March 27, 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 but subsequently granted the preliminary injunction on February 23. On February 26, Bayou Bridge filed a notice of appeal and a motion to stay the February 23 preliminary injunction order. On February 27, Judge Dick issued an opinion that clarified her February 23 preliminary injunction order and denied Bayou Bridge's February

26 motion to stay as moot. On March 1, Bayou Bridge filed a new notice of appeal and motion to stay the February 27 preliminary injunction order in the district court. On March 5, the district court denied the March 1 motion to stay the February 27 order.

On March 2, 2018, Bayou Bridge filed a motion to stay the preliminary injunction in the Fifth Circuit. On March 15, 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.

Rover

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover Pipeline, LLC ("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., and D&G Directional Drilling, Inc. d/b/a D&G Directional Drilling, LLC (collectively, with Rover and Pretec, "Defendants") were added as defendants on April 17, 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 Rover 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's answer to Ohio EPA's complaint is due on May 17, 2018.

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 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 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 March 31, 2018 and December 31, 2017, accruals of approximately $30 million and $33 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

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. ("Sunoco") before the Pennsylvania Public Utilities 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 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) Sunoco failed to warn the public of the dangers of the pipeline; (iii) the construction of ME2 and ME2x increase 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 West Whiteland 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 Sunoco 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 Sunoco 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 West Whiteland Township. A hearing before Administrative Law Judge Elizabeth H. Barnes on the emergency relief is scheduled for May 7 and 10, 2018.

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

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

No amounts have been recorded in our March 31, 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, the issuance of injunctions in affected areas and the filing of federally authorized citizen suits. Contingent losses related to all significant known environmental matters have been accrued and/or separately disclosed. However, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

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

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

In February 2017, we received letters from the DOJ and Louisiana Department of Environmental Quality notifying Sunoco Pipeline L.P. ("SPLP") and Mid-Valley Pipeline Company ("Mid-Valley") that enforcement actions were being pursued for three crude oil releases: (a) an estimated 550 barrels released from the Colmesneil-to-Chester pipeline in Tyler County, Texas ("Colmesneil") operated and owned by SPLP in February of 2013; (b) an estimated 4,509 barrels released from the Longview-to-Mayersville pipeline in Caddo Parish, Louisiana (a/k/a Milepost 51.5) operated by SPLP and owned by Mid-Valley in October of 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma operated and owned by SPLP in January of 2015. In May of 2017, we presented to the DOJ, EPA and Louisiana Department of Environmental Quality a summary of the emergency response and remedial efforts taken by SPLP after the releases occurred as well as operational changes instituted by SPLP to reduce the likelihood of future releases. In July 2017, we had a follow-up meeting with the DOJ, EPA and Louisiana Department of Environmental Quality during which the agencies presented their initial demand for civil penalties and injunctive relief. In short, the DOJ and EPA proposed federal penalties totaling $7 million for the three releases along with a demand for injunctive relief, and Louisiana Department of Environmental Quality proposed a state penalty of approximately $1 million to resolve the Caddo Parish release. We are currently working on a counteroffer to the Louisiana Department of Environmental Quality, and we are involved in settlement discussion with the agencies.

On January 3, 2018, PADEP issued an Administrative Order to Sunoco Pipeline L.P. 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 of 2017, during the construction of the project. Sunoco Pipeline L.P. 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 Sunoco Pipeline L.P. took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, Sunoco Pipeline L.P. entered into a Consent Order and Agreement with PADEP that (1) withdraws the Administrative Order; (2) establishes requirements for compliance with permits on a going forward basis; (3) resolves the non-compliance alleged in the Administrative Order; and (4) conditions restart of work on an agreement by Sunoco Pipeline L.P. to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, Sunoco Pipeline L.P. 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 Sunoco Pipeline L.P. had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. Sunoco Pipeline L.P. 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 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 March 31, 2018, Sunoco, Inc. had been named as a PRP at approximately 50 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.

	March 31, 2018	December 31, 2017
Current	$ 43	$ 36
Non-current	302	314
Total environmental liabilities	$ 345	$ 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 March 31, 2018 and 2017, the Partnership recorded $5 million and $2 million, respectively, of expenditures related to environmental cleanup programs.

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

Our pipeline operations are subject to regulation by the United States Department of Transportation under the 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.

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 months ended March 31, 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. 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.

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 business which provides compression services to customers engaged in the transportation of natural gas. 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 March 31, 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 March 31, 2018, the Partnership had $317 million in deferred revenues representing the current value of our future performance obligations.

The amount of revenue recognized in the current period that was included in the deferred revenue liability balance as of January 1, 2018 was $42 million.

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 March 31, 2018, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations is $35.66 billion and the Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	2018 (remainder)	2019	2020	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of March 31, 2018	$ 3,430	$ 4,596	$ 4,116	$ 23,520	$ 35,662

Practical Expedients Utilized by the Partnership

For the period ended March 31, 2018, 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.

The following table details our outstanding commodity-related derivatives:

	March 31, 2018		December 31, 2017	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	1,008	2018	1,078	2018
Basis Swaps IFERC/NYMEX [(1)]	82,493	2018-2020	48,510	2018-2020
Options – Puts	13,000	2018	13,000	2018
Options – Calls	460	2018	—	—
Power (Megawatt):				
Forwards	236,680	2018-2019	435,960	2018-2019
Futures	126,200	2018	(25,760)	2018
Options – Puts	238,400	2018	(153,600)	2018
Options – Calls	349,600	2018	137,600	2018
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	9,750	2018-2020	4,650	2018-2020
Swing Swaps IFERC	(24,825)	2018-2019	87,253	2018-2019
Fixed Swaps/Futures	(4,620)	2018-2019	(4,700)	2018-2019
Forward Physical Contracts	(224,178)	2018-2020	(145,105)	2018-2020
Natural Gas Liquid/Crude (MBbls) – Forwards/Swaps	38,875	2018-2019	6,679	2018-2019
Refined Products (MBbls) – Futures	(1,219)	2018-2019	(3,783)	2018-2019
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(18,685)	2018	(39,770)	2018
Fixed Swaps/Futures	(18,685)	2018	(39,770)	2018
Hedged Item – Inventory	18,685	2018	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.

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

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

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

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

Credit Risk

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

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

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

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

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	March 31, 2018	December 31, 2017	March 31, 2018	December 31, 2017
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ —	$ 14	$ —	$ (2)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	166	262	(206)	(281)
Commodity derivatives	86	44	(140)	(55)
Interest rate derivatives	—	—	(167)	(219)
	252	306	(513)	(555)
Total derivatives	$ 252	$ 320	$ (513)	$ (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:

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	March 31, 2018	December 31, 2017	March 31, 2018	December 31, 2017
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (167)	$ (219)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	86	44	(140)	(55)
Broker cleared derivative contracts	Other current assets (liabilities)	166	276	(206)	(283)
Total gross derivatives		252	320	(513)	(557)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(63)	(20)	63	20
Counterparty netting	Other current assets (liabilities)	(165)	(263)	165	263
Total net derivatives		$ 24	$ 37	$ (285)	$ (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.

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

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness	
		Three Months Ended March 31,	
		2018	2017
Derivatives in fair value hedging relationships (including hedged item):			
Commodity derivatives	Cost of products sold	$ 3	$ (4)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2018	2017
Derivatives not designated as hedging instruments:			
Commodity derivatives – Trading	Cost of products sold	$ 17	$ 11
Commodity derivatives – Non-trading	Cost of products sold	(73)	(10)
Interest rate derivatives	Gains on interest rate derivatives	52	5
Embedded derivatives	Other, net	—	1
Total		$ (4)	$ 7

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 March 31,	
	2018	2017
Affiliated revenues	$ 286	$ 118

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

	March 31, 2018	December 31, 2017
Accounts receivable from related companies:		
Sunoco LP	$ 209	$ 219
FGT	24	11
Other	107	88
Total accounts receivable from related companies:	$ 340	$ 318
Accounts payable to related companies:		
Sunoco LP	$ 194	$ 195
Other	50	14
Total accounts payable to related companies:	$ 244	$ 209

	March 31, 2018	December 31, 2017
Long-term notes receivable from related company:		
Sunoco LP	$ 83	$ 85

14. REPORTABLE SEGMENTS

Our financial statements currently 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 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 March 31,	
	2018	2017
Revenues:		
Intrastate transportation and storage:		
Revenues from external customers	$ 817	$ 768
Intersegment revenues	58	48
	875	816
Interstate transportation and storage:		
Revenues from external customers	313	231
Intersegment revenues	3	4
	316	235
Midstream:		
Revenues from external customers	440	565
Intersegment revenues	1,174	1,072
	1,614	1,637
NGL and refined products transportation and services:		
Revenues from external customers	2,458	2,118
Intersegment revenues	88	148
	2,546	2,266
Crude oil transportation and services:		
Revenues from external customers	3,731	2,575
Intersegment revenues	14	—
	3,745	2,575
All other:		
Revenues from external customers	521	638
Intersegment revenues	50	132
	571	770
Eliminations	(1,387)	(1,404)
Total revenues	$ 8,280	$ 6,895

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017*
Segment Adjusted EBITDA:		
Intrastate transportation and storage	$ 192	$ 169
Interstate transportation and storage	323	265
Midstream	377	320
NGL and refined products transportation and services	451	381
Crude oil transportation and services	464	187
All other	74	123
Total	1,881	1,445
Depreciation, depletion and amortization	(603)	(560)
Interest expense, net	(346)	(332)
Gain on Sunoco LP common unit repurchase	172	—
Gains on interest rate derivatives	52	5
Non-cash compensation expense	(20)	(23)
Unrealized gains (losses) on commodity risk management activities	(87)	64
Adjusted EBITDA related to unconsolidated affiliates	(185)	(239)
Equity in earnings (losses) of unconsolidated affiliates	(72)	73
Other, net	47	15
Income before income tax (expense) benefit	$ 839	$ 448

* As adjusted. See Note 1.

	March 31, 2018	December 31, 2017
Assets:		
Intrastate transportation and storage	$ 5,008	$ 5,020
Interstate transportation and storage	13,730	13,518
Midstream	20,199	20,004
NGL and refined products transportation and services	17,285	17,600
Crude oil transportation and services	17,401	17,736
All other	3,872	4,087
Total assets	$ 77,495	$ 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 Partners, L.P. is referred to as “Parent Guarantor” and Sunoco Logistics Partners Operations L.P. is referred to as “Subsidiary Issuer.” All other consolidated subsidiaries of the Partnership are collectively referred to as “Non-Guarantor Subsidiaries.”

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

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

	March 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$ —	$ —	$ 446	$ —	$ 446
All other current assets	33	57	5,526	(314)	5,302
Property, plant and equipment, net	—	—	59,373	—	59,373
Investments in unconsolidated affiliates	48,973	11,957	3,258	(60,930)	3,258
All other assets	7	—	9,109	—	9,116
Total assets	$ 49,013	$ 12,014	$ 77,712	$ (61,244)	$ 77,495
Current liabilities	$ (1,113)	$ (3,665)	$ 11,315	$ (314)	$ 6,223
Non-current liabilities	22,124	7,607	7,456	—	37,187
Noncontrolling interest	—	—	6,086	—	6,086
Total partners’ capital	28,002	8,072	52,855	(60,930)	27,999
Total liabilities and equity	$ 49,013	$ 12,014	$ 77,712	$ (61,244)	$ 77,495

	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

	Three Months Ended March 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 8,280	$ —	$ 8,280
Operating costs, expenses, and other	—	—	7,307	—	7,307
Operating income	—	—	973	—	973
Interest expense, net	(278)	(41)	(27)	—	(346)
Equity in earnings (losses) of unconsolidated affiliates	941	260	(72)	(1,201)	(72)
Gain on Sunoco LP common unit repurchase	—	—	172	—	172
Gains on interest rate derivatives	52	—	—	—	52
Other, net	—	—	60	—	60
Income before income tax benefit	715	219	1,106	(1,201)	839
Income tax benefit	—	—	(40)	—	(40)
Net income	715	219	1,146	(1,201)	879
Less: Net income attributable to noncontrolling interest	—	—	164	—	164
Net income attributable to partners	$ 715	$ 219	$ 982	$ (1,201)	$ 715
Other comprehensive income	$ —	$ —	$ 1	$ —	$ 1
Comprehensive income	715	219	1,147	(1,201)	880
Comprehensive income attributable to noncontrolling interest	—	—	164	—	164
Comprehensive income attributable to partners	$ 715	$ 219	$ 983	$ (1,201)	$ 716

	Three Months Ended March 31, 2017*				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ —	$ 6,895	$ —	$ 6,895
Operating costs, expenses, and other	—	—	6,212	—	6,212
Operating income	—	—	683	—	683
Interest expense, net	—	(42)	(290)	—	(332)
Equity in earnings of unconsolidated affiliates	811	628	73	(1,439)	73
Gains on interest rate derivatives	—	—	5	—	5
Other, net	—	—	19	—	19
Income before income tax expense	811	586	490	(1,439)	448
Income tax expense	—	—	55	—	55
Net income	811	586	435	(1,439)	393
Less: Net income attributable to noncontrolling interest	—	—	62	—	62
Net income attributable to partners	$ 811	$ 586	$ 373	$ (1,439)	$ 331
Comprehensive income	811	586	435	(1,439)	393
Comprehensive income attributable to noncontrolling interest	—	—	62	—	62
Comprehensive income attributable to partners	$ 811	$ 586	$ 373	$ (1,439)	$ 331

* As adjusted. See Note 1.

	Three Months Ended March 31, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 1,147	$ 434	$ 2,034	$ (1,841)	$ 1,774
Cash flows used in investing activities	(1,554)	(431)	(999)	1,841	(1,143)
Cash flows provided by (used in) financing activities	407	—	(898)	—	(491)
Change in cash	—	3	137	—	140
Cash at beginning of period	—	(3)	309	—	306
Cash at end of period	$ —	$ —	$ 446	$ —	$ 446

	Three Months Ended March 31, 2017*				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$ 811	$ 559	$ 1,001	$ (1,439)	$ 932
Cash flows used in investing activities	(534)	(11)	(614)	1,439	280
Cash flows used in financing activities	(277)	(552)	(452)	—	(1,281)
Change in cash	—	(4)	(65)	—	(69)
Cash at beginning of period	—	41	319	—	360
Cash at end of period	$ —	$ 37	$ 254	$ —	$ 291

* As adjusted. See Note 1.

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

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; and (ii) the consolidated financial statements and management's discussion and analysis of financial condition and results of operations included in 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 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

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 is expected to resume service in the second quarter of 2018 and ETP will be 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 late fourth quarter of 2018.

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 our 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 and CDM E&T for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 common units representing limited partner interests in USAC ("USAC Common Units"), (ii) 6,397,965 units of a newly authorized and established class of units representing limited partner interests in USAC ("Class B Units") and (iii) $1.23 billion in cash, including customary closing adjustments (the "CDM Contribution"). The 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 Class B Units will not participate in distributions for the first four quarters following the closing date of April 2, 2018. Each 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.

Beginning April 2018, ETP's consolidated financial statements will reflect an equity method investment in USAC. CDM and CDM E&T's assets and liabilities have not been reflected as held for sale, nor have CDM and CDM E&T's results been reflected as discontinued operations in these financial statements.

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, FERC addressed treatment of federal income tax allowances in regulated entity rates. 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. 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 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. Requests for rehearing or clarification of the Revised Policy Statement which were filed on or before April 16, 2018, may change FERC's policy on the treatment of income taxes and impacts that such changes may have on the rates ETP can charge for FERC regulated transportation services are unknown at this time.

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 FERC is whether, and if so how, FERC should address changes relating to accumulated deferred income taxes and bonus depreciation. Comments in response to the 2017 Tax Law NOI are due on or before May 21, 2018. It is unknown at this time what actions that 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. The NOPR proposes a new rule that will, if it becomes a final rule, require 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 NOPR suggests that this information will allow FERC and other stakeholders to evaluate the impacts of the Tax Act and the Revised Policy Statement on each individual pipeline's rates. The NOPR proposes that each FERC regulated natural gas pipeline will 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. Comments on the NOPR were due April 25, 2018, and following review of the comments, FERC may issue a final rule. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulation in its proposed form 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 NOPR or NOI, the FERC or our shippers may challenge the cost of service rates we charge. 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 FERC's determination of just and reasonable cost of service rates. Although changes in these two tax related components may decrease, other components in the cost of service rate calculation may increase and result in a newly calculated cost of service rate that is the same as or greater than the prior cost of service rate. Moreover, we receive revenues from our pipelines based on a variety of rate structures, including cost of service rates, negotiated rates, discounted rates and market-based rates. Many of our interstate pipelines, such as ETC Tiger Pipeline, LLC, MEP and FEP, have negotiated market rates that were agreed to by customers in connection with long-term contracts entered into to support the construction of the pipelines. Other systems, such as FGT, Transwestern and Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. We do not expect market-based rates, negotiated rates or discounted rates that are not tied to the cost of service rates to be affected by the Revised Policy Statement or any final regulations that may result from the March 15, 2018 proposals. The revenues we receive from natural gas transportation services we provide pursuant to cost of service based rates may decrease in the future as a result of the ultimate outcome of the NOI, the NOPR, 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.

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. 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

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. 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 the Page 700 of FERC Form No. 6. This information will be used by 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. 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 FERC's determination of the appropriate pipeline index. Accordingly, depending on 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 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 March 31,		
	2018	2017*	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 192	$ 169	$ 23
Interstate transportation and storage	323	265	58
Midstream	377	320	57
NGL and refined products transportation and services	451	381	70
Crude oil transportation and services	464	187	277
All other	74	123	(49)
Total	1,881	1,445	436
Depreciation, depletion and amortization	(603)	(560)	(43)
Interest expense, net	(346)	(332)	(14)
Gain on Sunoco LP common unit repurchase	172	—	172
Gains on interest rate derivatives	52	5	47
Non-cash compensation expense	(20)	(23)	3
Unrealized gains (losses) on commodity risk management activities	(87)	64	(151)
Adjusted EBITDA related to unconsolidated affiliates	(185)	(239)	54
Equity in earnings (losses) of unconsolidated affiliates	(72)	73	(145)
Other, net	47	15	32
Income before income tax (expense) benefit	839	448	391
Income tax (expense) benefit	40	(55)	95
Net income	$ 879	$ 393	$ 486

* 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 months ended March 31, 2018 compared to the same period last year primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

Interest Expense, net. Interest expense, net of capitalized interest, increased for the three months ended March 31, 2018 compared to the same period last year primarily attributable to increases in long-term debt, including increased borrowings under our revolving credit facilities.

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.

Gains on Interest Rate Derivatives. Gains on interest rate derivatives during the three months ended March 31, 2018 and 2017 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 (Losses) 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 months ended March 31, 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 a $67 million deferred benefit adjustment during the three months ended March 31, 2018 as the result of a state statutory rate reduction.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended March 31,		
	2018	2017	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 27	$ 21	$ 6
FEP	14	12	2
MEP	9	10	(1)
HPC	3	7	(4)
Sunoco LP	(151)	(14)	(137)
Other	26	37	(11)
Total equity in earnings (losses) of unconsolidated affiliates	$ (72)	$ 73	$ (145)
Adjusted EBITDA related to unconsolidated affiliates[(1)]:			
Citrus	$ 75	$ 75	$ —
FEP	19	18	1
MEP	22	22	—
HPC	9	15	(6)
Sunoco LP	29	54	(25)
Other	31	55	(24)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 185	$ 239	$ (54)
Distributions received from unconsolidated affiliates:			
Citrus	$ 46	$ 41	$ 5
FEP	17	—	17
MEP	13	73	(60)
Sunoco LP	36	35	1
Other	21	23	(2)
Total distributions received from unconsolidated affiliates	$ 133	$ 172	$ (39)

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

Segment Operating Results

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

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

- *Segment margin, operating expenses,* and *selling, general and administrative expenses*. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.
- *Unrealized gains or losses on commodity risk management activities*. These are the unrealized amounts that are included in cost of products sold to calculate segment margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.

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

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

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

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

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

	Three Months Ended March 31,	
	2018	2017
Intrastate transportation and storage	$ 171	$ 182
Interstate transportation and storage	316	235
Midstream	553	513
NGL and refined products transportation and services	600	559
Crude oil transportation and services	568	272
All other	95	102
Intersegment eliminations	(11)	(18)
Total segment margin	2,292	1,845
Less:		
Operating expenses	604	492
Depreciation, depletion and amortization	603	560
Selling, general and administrative	112	110
Operating income	$ 973	$ 683

Intrastate Transportation and Storage

	Three Months Ended March 31,		
	2018	2017	Change
Natural gas transported (BBtu/d)	9,271	7,870	1,401
Withdrawals from storage natural gas inventory (BBtu)	17,703	23,093	(5,390)
Revenues	$ 875	$ 816	$ 59
Cost of products sold	704	634	70
Segment margin	171	182	(11)
Unrealized losses on commodity risk management activities	53	15	38
Operating expenses, excluding non-cash compensation expense	(39)	(38)	(1)
Selling, general and administrative expenses, excluding non-cash compensation expense	(6)	(6)	—
Adjusted EBITDA related to unconsolidated affiliates	13	16	(3)
Segment Adjusted EBITDA	$ 192	$ 169	$ 23

Volumes. For the three months ended March 31, 2018 compared to the same period last year, transported volumes increased primarily due to higher demand for exports to Mexico, the addition of new pipelines and more favorable market pricing.

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

	Three Months Ended March 31,		
	2018	2017	Change
Transportation fees	$ 117	$ 124	$ (7)
Natural gas sales and other (excluding unrealized gains and losses)	91	33	58
Retained fuel revenues (excluding unrealized gains and losses)	13	13	—
Storage margin (excluding unrealized gains and losses)	3	27	(24)
Unrealized losses on commodity risk management activities	(53)	(15)	(38)
Total segment margin	$ 171	$ 182	$ (11)

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $58 million in realized natural gas sales and other due to higher realized gains from pipeline optimization activity; offset by
- a decrease of $24 million in realized storage margin primarily due to an adjustment to the Bammel storage inventory;
- a decrease of $7 million in transportation fees due to renegotiated contracts resulting in lower billed volumes;
- an increase of $1 million in operating expenses primarily due to higher expense projects; and
- a decrease of $3 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to a decrease of $3 million from lower demand volumes related to renegotiation of a contract and a decrease of $3 million due to a reserve recorded in the prior period pursuant to the bankruptcy filing of a transport customer, partially offset by an increase of $3 million related to two new joint venture pipelines placed in service in 2017.

Interstate Transportation and Storage

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Change
Natural gas transported (BBtu/d)	8,204	5,656	2,548
Natural gas sold (BBtu/d)	17	17	—
Revenues	$ 316	$ 235	$ 81
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(94)	(74)	(20)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(17)	(12)	(5)
Adjusted EBITDA related to unconsolidated affiliates	116	115	1
Other	2	1	1
Segment Adjusted EBITDA	$ 323	$ 265	$ 58

Volumes. For the three months ended March 31, 2018 compared to the same period last year, transported volumes reflected an increase of 1,470 BBtu/d as a result of the partial in service of the Rover pipeline, an increase of 444 BBtu/d on the Tiger pipeline as a result of production increases in the Haynesville Shale and deliveries into third party storage and the intrastate markets, and an increase of 402 BBtu/d and 229 BBtu/d on the Panhandle and Trunkline pipelines, respectively, resulting from higher demand due to colder weather.

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net effect of the following:

- an increase of $49 million due to the partial in service of the Rover pipeline which reflected increases of $82 million in revenues, $26 million in operating expenses and $7 million in general and administrative expenses;
- a decrease of $6 million in operating expenses, excluding the incremental expenses related to the Rover pipeline discussed above, primarily due to lower allocated costs, reduction in project maintenance work and lower transportation and storage related expenses; and
- a decrease of $2 million in general and administrative expenses, excluding the incremental expenses related to the Rover pipeline discussed above, primarily due to lower allocated costs and insurance reserves.

Midstream

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Change
Gathered volumes (BBtu/d)	11,306	10,232	1,074
NGLs produced (MBbls/d)	503	445	58
Equity NGLs (MBbls/d)	28	26	2
Revenues	$ 1,614	$ 1,637	$ (23)
Cost of products sold	1,061	1,124	(63)
Segment margin	553	513	40
Unrealized gains on commodity risk management activities	—	(16)	16
Operating expenses, excluding non-cash compensation expense	(164)	(161)	(3)
Selling, general and administrative expenses, excluding non-cash compensation expense	(20)	(23)	3
Adjusted EBITDA related to unconsolidated affiliates	7	7	—
Other	1	—	1
Segment Adjusted EBITDA	$ 377	$ 320	$ 57

Volumes. For the three months ended March 31, 2018 compared to the same period last year, gathered volumes and NGL production increased primarily due to increases in the Permian and Northeast regions, partially offset by basin declines in the Ark-La-Tex, North Texas and Mid-Continent/Panhandle regions.

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

	Three Months Ended March 31,		
	2018	2017	Change
Gathering and processing fee-based revenues	$ 421	$ 408	$ 13
Non fee-based contracts and processing (excluding unrealized gains and losses)	132	89	43
Unrealized gains on commodity risk management activities	—	16	(16)
Total segment margin	$ 553	$ 513	$ 40

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net effects of the following:

- an increase of $27 million in non fee-based margin due to increased throughput volumes in the Permian and South Texas regions;
- an increase of $16 million in non fee-based margin due to an $11 million increase resulting from higher crude and NGL prices and a $5 million increase in settled price risk management activity;
- an increase of $13 million in fee-based revenue due to growth in the Permian and Northeast regions, offset by declines in Ark-La-Tex, North Texas and the Mid-Continent/Panhandle regions; and
- a decrease of $3 million in selling, general and administrative expenses due to lower employee costs and professional fees; offset by
- an increase of $3 million in operating expenses primarily due to an increase of $2 million in employee costs and an increase of $1 million in ad valorem taxes.

NGL and Refined Products Transportation and Services

	Three Months Ended March 31,		
	2018	2017	Change
NGL transportation volumes (MBbls/d)	936	816	120
Refined products transportation volumes (MBbls/d)	620	624	(4)
NGL and refined products terminal volumes (MBbls/d)	702	790	(88)
NGL fractionation volumes (MBbls/d)	472	433	39
Revenues	$ 2,546	$ 2,266	$ 280
Cost of products sold	1,946	1,707	239
Segment margin	600	559	41
Unrealized gains on commodity risk management activities	(13)	(50)	37
Operating expenses, excluding non-cash compensation expense	(139)	(127)	(12)
Selling, general and administrative expenses, excluding non-cash compensation expense	(18)	(19)	1
Adjusted EBITDA related to unconsolidated affiliates	21	17	4
Other	—	1	(1)
Segment Adjusted EBITDA	$ 451	$ 381	$ 70

Volumes. For the three months ended March 31, 2018 compared to the same period last year, NGL transportation volumes increased primarily from the Permian region, Mariner West pipeline and Mariner South pipeline, partially offset by decreased throughput volumes on Mariner East I due to system downtime in March 2018.

Refined products transportation volumes decreased slightly for the three months ended March 31, 2018 compared to the same period last year primarily due to lower throughput volumes from the Midwest and Northeast regions, partially offset by increased throughput volumes from the Southwest region.

NGL and refined products terminal volumes decreased for the three months ended March 31, 2018 compared to the same period last year primarily due to the sale of one of our refined product marketing terminals in April 2017, lower volumes loaded for export at our Nederland terminal and lower throughput volumes at our Marcus Hook Industrial Complex due to system downtime on our Mariner East I pipeline in March 2018.

Average fractionated volumes at our Mont Belvieu, Texas fractionation facility increased 11% for the three months ended March 31, 2018 compared to the same period last year primarily due to increased volumes from Permian producers.

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

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Change
Fractionators and Refinery services margin	$ 134	$ 120	$ 14
Transportation margin	266	233	33
Storage margin	56	57	(1)
Terminal Services margin	94	87	7
Marketing margin	37	12	25
Unrealized gains on commodity risk management activities	13	50	(37)
Total segment margin	$ 600	$ 559	$ 41

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impact of the following:

- an increase of $33 million in transportation margin due to a $33 million increase resulting from increased producer volumes from the Permian region on our Texas NGL pipelines and a $6 million increase due to higher throughput on Mariner West driven by end user facility constraints in the prior period. These increases were offset by a $6 million decrease resulting from lower throughput on Mariner East I due to system downtime in March 2018;
- an increase of $25 million in marketing margin due to gains of $9 million from optimizing sales of purity product from our Mont Belvieu fractionators, as well as an $8 million increase from our butane blending operations and an $8 million increase from sales of domestic propane and other products at our Marcus Hook Industrial Complex;
- an increase of $14 million in fractionation and refinery services margin primarily due to an $8 million increase resulting from higher NGL volumes from the Permian region feeding our Mont Belvieu fractionation facility and a $7 million increase from blending gains as a result of improved market pricing;
- an increase of $7 million in terminal services margin due to a $10 million increase resulting from a change in the classification of certain customer reimbursements previously recorded in operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018. This increase was offset by a $3 million decrease from our marketing terminal volumes primarily due to the sale of one of our terminals in April 2017; and
- an increase of $4 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to annual true-up payments from one of our unconsolidated refined product pipelines recorded in January 2018; offset by
- an increase of $12 million in operating expenses primarily due to a change in the classification of certain customer reimbursements previously recorded in operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018.

Crude Oil Transportation and Services

	Three Months Ended March 31,		
	2018	2017	Change
Crude transportation volumes (MBbls/d)	3,827	3,042	785
Crude terminals volumes (MBbls/d)	1,940	1,777	163
Revenues	$ 3,745	$ 2,575	$ 1,170
Cost of products sold	3,177	2,303	874
Segment margin	568	272	296
Unrealized losses on commodity risk management activities	43	—	43
Operating expenses, excluding non-cash compensation expense	(127)	(72)	(55)
Selling, general and administrative expenses, excluding non-cash compensation expense	(22)	(17)	(5)
Adjusted EBITDA related to unconsolidated affiliates	2	4	(2)
Segment Adjusted EBITDA	$ 464	$ 187	$ 277

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the following:

- an increase of $339 million in segment margin (excluding unrealized losses on commodity risk management activities) due to a $222 million increase resulting primarily from placing our Bakken pipeline in service in the second quarter of 2017 as well as a $25 million increase resulting from increased throughput, primarily from Permian producers, on existing pipeline assets; an $85 million increase (excluding $43 million in unrealized losses on commodity risk management activities) from our crude oil acquisition and marketing business primarily resulting from more favorable market price differentials between the West Texas and Gulf Coast markets; and a $7 million increase from higher ship loading and throughput fees at our Nederland terminal due to an increase in exports; offset by
- an increase of $55 million in operating expenses primarily due to a $26 million increase resulting from placing our Bakken pipeline in service in the second quarter of 2017; a $12 million increase resulting from the addition of certain joint venture crude transportation assets in the second quarter of 2017; and a $15 million increase from existing transportation assets mainly due to higher ad valorem taxes, management fees and pipeline loss allowance; and
- an increase of $5 million in selling, general and administrative expenses due primarily to insurance and Bakken management fees.

All Other

	Three Months Ended March 31,		
	2018	2017	Change
Revenues	$ 571	$ 770	$ (199)
Cost of products sold	476	668	(192)
Segment margin	95	102	(7)
Unrealized (gains) losses on commodity risk management activities	4	(13)	17
Operating expenses, excluding non-cash compensation expense	(31)	(21)	(10)
Selling, general and administrative expenses, excluding non-cash compensation expense	(18)	(21)	3
Adjusted EBITDA related to unconsolidated affiliates	26	80	(54)
Other and eliminations	(2)	(4)	2
Segment Adjusted EBITDA	$ 74	$ 123	$ (49)

Amounts reflected in our all other segment primarily include:

- our equity method investment in limited partnership units of Sunoco LP consisting of 26.2 million and 43.5 million units, representing 31.8% and 43.7% of Sunoco LP's total outstanding common units as of March 31, 2018 and March 31, 2017, respectively. 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;
- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in coal handling facilities.

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment decreased primarily due to the net impact of the following:

- a decrease of $54 million in Adjusted EBITDA related to unconsolidated affiliates, primarily reflecting a decrease of $30 million from our investment in PES due to lower earnings and a decrease of $25 million from our investment in Sunoco LP primarily due to Sunoco LP's sale of retail assets, as well as a decrease in our ownership interest in Sunoco LP subsequent to the repurchase of common units by Sunoco LP in February 2018;
- an increase of $10 million in operating expenses primarily attributable to an increase of $8 million in the compression business; offset by
- an increase of $11 million from commodity trading activities; and
- a decrease of $3 million in selling, general and administrative expenses due to lower merger and acquisition costs.

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:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 250	$ 275	$ 30	$ 35
Interstate transportation and storage [(1)]	500	550	115	120
Midstream	800	850	120	130
NGL and refined products transportation and services	2,450	2,500	65	75
Crude oil transportation and services [(1)]	350	450	90	100
All other (including eliminations)	75	100	60	65
Total capital expenditures	$ 4,425	$ 4,725	$ 480	$ 525

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

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

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

Cash Flows

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

Operating Activities

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

Three months ended March 31, 2018 compared to three months ended March 31, 2017. Cash provided by operating activities during 2018 was $1.77 billion compared to $932 million for 2017 and net income was $879 million and $393 million for 2018 and 2017, respectively. The difference between net income and cash provided by operating activities for the three months ended March 31, 2018 primarily consisted of net changes in operating assets and liabilities of $392 million and non-cash items totaling $405 million.

The non-cash activity in 2018 and 2017 consisted primarily of depreciation, depletion and amortization of $603 million and $560 million, respectively, non-cash compensation expense of $20 million and $23 million, respectively, and equity in losses of unconsolidated affiliates of $72 million and equity in earnings of unconsolidated affiliates of $73 million, respectively. Non-cash activity in 2018 also included a gain on the sale of Sunoco LP units of $172 million and a decrease in deferred income taxes of $40 million. Non-cash activity in 2017 also included an increase in deferred income taxes of $54 million.

Cash paid for interest, net of interest capitalized, was $278 million and $351 million for the three months ended March 31, 2018 and 2017, respectively.

Capitalized interest was $80 million and $59 million for the three months ended March 31, 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.

Three months ended March 31, 2018 compared to three months ended March 31, 2017. Cash used in investing activities during 2018 was $1.14 billion compared to $280 million provided by investing activities 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 $1.70 billion compared to $1.38 billion for 2017. Additional detail related to our capital expenditures is provided in the table below. During 2018, we received $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, paid $280 million in cash for the acquisition of PennTex noncontrolling interest and paid $38 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 three months ended March 31, 2018:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$ 139	$ 15	$ 154
Interstate transportation and storage	131	10	141
Midstream	194	25	219
NGL and refined products transportation and services	530	9	539
Crude oil transportation and services	58	8	66
All other (including eliminations)	31	21	52
Total capital expenditures	$ 1,083	$ 88	$ 1,171

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.

Three months ended March 31, 2018 compared to three months ended March 31, 2017. Cash used in financing activities during 2018 was $491 million compared to $1.28 billion for 2017. In 2018 and 2017, we received net proceeds from Common Unit offerings of $20 million and $826 million, respectively. During 2018, we had a net increase in our debt level of $416 million compared to a net decrease of $1.10 billion for 2017. We have paid distributions of $945 million to our partners in 2018 compared to $896 million in 2017. We have also paid distributions of $183 million to noncontrolling interests in 2018 compared to $148 million in 2017. In addition, we have received capital contributions of $229 million in cash from noncontrolling interests in 2018 compared to $106 million in 2017. During 2018, we also repurchased common units for cash of $24 million. During 2017, we also repurchased our outstanding Legacy ETP Preferred Units for cash of $53 million and incurred debt issuance costs of $19 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 (i) $800 million principal amount of 6.375% senior notes due 2023 issued by Sunoco LP, (ii) $800 million principal amount of 6.25% senior notes due 2021 issued by Sunoco LP and (iii) $2.035 billion aggregate principal for Sunoco LP's term loan due 2019. In December 2016, Retail Holdings contributed its interests in Sunoco LP, along with the assignment of the guarantee of Sunoco LP's senior notes, to its subsidiary, ETC M-A Acquisition LLC ("ETC M-A").

On January 23, 2018, Sunoco LP redeemed the previously guaranteed senior notes and issued the following 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.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	March 31, 2018	December 31, 2017
ETP Senior Notes	$ 27,005	$ 27,005
Transwestern Senior Notes	575	575
Panhandle Senior Notes	785	785
Credit facilities and commercial paper:		
ETP $4.00 billion Revolving Credit Facility due December 2022 (1)	2,756	2,292
ETP $1.00 billion 364-Day Credit Facility due November 2018 (2)	—	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	61	61
Deferred debt issuance costs	(173)	(179)
Total debt	33,513	33,094
Less: current maturities of long-term debt	404	407
Long-term debt, less current maturities	$ 33,109	$ 32,687

(1) Includes $1.93 billion and $2.01 billion of commercial paper outstanding at March 31, 2018 and December 31, 2017, respectively.

(2) Borrowings under the 364-day credit facility were classified as long-term debt based on the Partnership's ability and intent to refinance such borrowings on a long-term basis.

Credit Facilities and Commercial Paper

ETP Five-Year Credit Facility

ETP's revolving credit facility (the "ETP Five-Year Credit Facility") allows for unsecured borrowings up to $4.00 billion and matures in December 2022. 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 March 31, 2018, the ETP Five-Year Credit Facility had $2.76 billion outstanding, of which $1.93 billion was commercial paper. The amount available for future borrowings was $1.09 billion after taking into account letters of credit of $155 million. The weighted average interest rate on the total amount outstanding as of March 31, 2018 was 2.92%.

ETP 364-Day Facility

ETP's 364-day term loan facility (the "ETP 364-Day Facility") allows for unsecured borrowings up to $1.00 billion and matures on November 30, 2018. As of March 31, 2018, the ETP 364-Day Facility had no outstanding borrowings.

Bakken Credit Facility

In August 2016, Energy Transfer Partners, L.P., Sunoco Logistics and Phillips 66 completed project-level financing of the Bakken Pipeline. The $2.50 billion credit facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects and matures in August 2019 (the "Bakken Credit Facility"). As of March 31, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings. The weighted average interest rate on the total amount outstanding as of March 31, 2018 was 3.31%.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of March 31, 2018.

CASH DISTRIBUTIONS

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

Distributions on common units declared and/or paid by the Partnership subsequent to December 31, 2017 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

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

			Distribution per Preferred Unit	
Quarter Ended	Record Date	Payment Date	Series A	Series B
December 31, 2017	February 1, 2018	February 15, 2018	$ 15.451	$ 16.378

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

	Three Months Ended March 31,	
	2018	2017
Limited Partners:		
Common Units held by public	$ 642	$ 567
Common Units held by ETE	16	15
General Partner interest and incentive distributions held by ETE	449	381
IDR relinquishments	(42)	(157)
Total distributions declared to partners	$ 1,065	$ 806

In connection with previous transactions, ETE agreed to relinquish its right to the following amounts of incentive distributions in future periods:

	Total Year
2018 (remainder)	$ 111
2019	128
Each year beyond 2019	33

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 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.

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.

	March 31, 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	1,008	$ —	$ —	1,078	$ —	$ —
Basis Swaps IFERC/NYMEX [(1)]	82,493	6	—	48,510	2	1
Options – Puts	13,000	—	—	13,000	—	—
Options – Calls	460	—	—	—	—	—
Power (Megawatt):						
Forwards	236,680	5	1	435,960	1	1
Futures	126,200	—	—	(25,760)	—	—
Options – Puts	238,400	1	1	(153,600)	—	1
Options – Calls	349,600	(1)	1	137,600	—	—
Crude (MBbls) – Futures	—	—	—	—	1	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	9,750	(52)	15	4,650	(13)	4
Swing Swaps IFERC	(24,825)	—	—	87,253	(2)	1
Fixed Swaps/Futures	(4,620)	1	7	(4,700)	(1)	2
Forward Physical Contracts	(224,178)	1	—	(145,105)	6	41
Natural Gas Liquid/Crude (MBbls) – Forwards/Swaps	38,875	(54)	7	6,679	1	25
Refined Products (MBbls) – Futures	(1,219)	(1)	9	(3,783)	(25)	4
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(18,685)	—	—	(39,770)	(2)	—
Fixed Swaps/Futures	(18,685)	—	6	(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 March 31, 2018, we had $5.86 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $59 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

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

		Notional Amount Outstanding	
Term	Type[1]	March 31, 2018	December 31, 2017
July 2018[2]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	$ 300	$ 300
July 2019[2]	Forward-starting to pay a fixed rate of 3.64% and receive a floating rate	300	300
July 2020[2]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	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 $230 million as of March 31, 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 $11 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 March 31, 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

In connection with the Partnership's adoption of ASC 606 effective January 1, 2018, 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. The Partnership's adoption and implementation of ASC 606 is discussed in Note 1 to the consolidated financial statements included in "Item 1. Financial Statements."

There have been no changes in our internal controls, other than those discussed above, 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 March 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see 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 Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2018.

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.

In August 2017, the Delaware Department of Natural Resources & Environmental Control issued an Air NOV at the Marcus Hook Industrial Complex related to unpermitted sources going to the ethylene complex flare. In March 2018, we settled the matter under a reconciliation order for $750,000. The matter is now closed and all sources going to the flare are permitted.

In addition, on May 10, 2017, the FERC prohibited Rover from conducting HDD activities at 27 sites in Ohio. On July 31, 2017, the FERC issued an independent third party assessment of what led to the release at the Tuscarawas River site and what Rover can do to prevent reoccurrence once the HDD suspension is lifted. Rover has implemented the suggestions in the assessment and additional voluntary protocols. The FERC has authorized Rover to resume HDD activities at all sites.

Energy Transfer Company Field Services received NOV REG-0569-1701 on June 6, 2017 for emission events that occurred January 1, 2017 through April 16, 2017 at the Jal 3 gas plant. On September 11, 2017, the New Mexico Environmental Department sent ETP a settlement offer to resolve the NOV for a penalty of $596,278. Negotiations for this settlement offer are ongoing.

Energy Transfer Field Services received NOV REG-0569-1702 on December 8, 2017 for emission events that occurred April 17, 2017 through September 23, 2017 at the Jal 3 gas plant. On January 31, 2018, ETP received a settlement offer to resolve the NOV for a penalty of $602,138. Negotiations for this settlement offer are ongoing.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the environmental proceedings listed above were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report governmental proceedings if we reasonably believe that such proceedings will result in monetary sanctions in excess of $100,000.

ITEM 1A. RISK FACTORS

Except as set forth below, 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 filed with the SEC on February 23, 2018 for our previous fiscal year ended December 31, 2017.

Our interstate natural gas pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services, which may prevent us from fully recovering our costs.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of our interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs.

We are required to file tariff rates (also known as recourse rates) with the FERC that shippers may pay for interstate natural gas transportation services. We may also agree to discount these rates on a not unduly discriminatory basis or negotiate rates with shippers who elect not to pay the recourse rates. The FERC must approve or accept all rate filings for us to be allowed to charge such rates.

The FERC may review existing tariff rates on its own initiative or upon receipt of a complaint filed by a third party. The FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. The FERC has recently exercised this authority with respect to several other pipeline companies. If the FERC were to initiate a proceeding against us and find that our rates were not just and reasonable or unduly discriminatory, the maximum rates we are permitted to charge may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

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

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

On December 22, 2017, the Tax Act was enacted, which reduced the highest marginal United States federal corporate income tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017. In a series of related proposals on March 15, 2018, the FERC has proposed a new policy that will no longer allow master limited partnerships to recover an income tax allowance in their cost of service rates, and the FERC also proposed rules for implementing this revised policy and the corporate income tax rate reduction pursuant to the Tax Act with respect to natural gas pipeline rates. The proposed rules, if they become final, would require all FERC regulated natural gas pipelines that have cost of service rates for service to make a one-time filing providing certain financial information that will allow the FERC and other stakeholders to evaluate the impacts of the revised policy and the corporate income tax rate reduction on each individual pipeline’s rates, and to select one of four options: file a limited NGA Section 4 filing reducing its rates only as required related to the revised policy and the Tax Act, 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. See Recent Developments in “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations” for information regarding recent regulatory updates.

We cannot predict the outcome of the NOPR, but the cost of service rates we are permitted to charge our customers for transportation services could be impacted if any of our FERC regulated natural gas pipelines files a limited or general NGA Section 4 rate filing or if the FERC or customers challenge the cost of service rates that these entities are authorized to charge. If FERC requires us to establish new tariff rates for our regulated natural gas pipelines that receive revenue based on cost of service rates as a result of lower federal corporate income tax rates and the Revised Policy Statement, it is possible the new tariff rates would be lower than our current cost of services rates which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

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

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

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

- terms and conditions of service;
- the types of services interstate pipelines may or must offer their customers;
- construction of new facilities;

- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

The Pipeline Certification NOI initiated a review of the FERC's 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. 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.

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

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

The primary ratemaking methodology used by the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. The FERC's ratemaking methodologies may limit our ability to set rates based on our costs or may delay the use of rates that reflect increased costs. In October 2016, FERC issued an Advance Notice of Proposed Rulemaking seeking comment on a number of proposals, including: (i) whether the Commission should deny any increase in a rate ceiling or annual index-based rate increase if a pipeline's revenues exceed total costs by 15 percent for the prior two years; (ii) a new percentage comparison test that would deny a proposed increase to a pipeline's rate or ceiling level greater than 5 percent above the barrel-mile cost changes; and (iii) a requirement that all pipelines file indexed ceiling levels annually, with the ceiling levels subject to challenge and restricting the pipeline's ability to carry forward the full indexed increase to a future period. The comment period with respect to the proposed rules ended March 17, 2017. FERC has not yet taken any further action on the proposed rule. If the FERC's indexing methodology changes, the new methodology could materially and adversely affect our financial condition, results of operations or cash flows.

Under the United States Environmental Protection Agency Act of 1992, certain interstate pipeline rates were deemed just and reasonable or "grandfathered." Revenues are derived from such grandfathered rates on most of our FERC regulated pipelines. A person challenging a grandfathered rate must, as a threshold matter, establish a substantial change since the date of enactment of the Energy Policy Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. If the FERC were to find a substantial change in circumstances, then the existing rates could be subject to detailed review and there is a risk that some rates could be found to be in excess of levels justified by the pipeline's costs. In such event, the FERC could order us to reduce pipeline rates prospectively and to pay refunds to shippers.

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

The FERC's Revised Policy Statement requires the reduced maximum corporate tax rate to be reflected in initial liquids cost of service rates and cost of service rate changes going forward and in future filings of Page 700 of FERC Form No. 6. FERC will consider the information provided by pipelines in Page 700 of FERC Form No. in its 2020 five-year review of the liquids pipeline index level. See Recent Developments in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" for information regarding recent regulatory updates. We cannot predict the outcome of the 2020 liquids pipeline index five-year review, but the rates we are permitted to charge our customers for cost of service based liquids transportation services could be impacted. If FERC requires us to establish new tariff rates for our regulated liquids pipelines that reflect a lower federal corporate income tax rate and the Revised Policy Statement, it is possible the rates would be reduced, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

Treatment of distributions on our preferred units as guaranteed payments for the use of capital creates a different tax treatment for the holders of preferred units than the holders of our common units and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

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

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

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

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

All holders of our preferred units are urged to consult a tax advisor with respect to the consequences of owning our preferred units.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table discloses purchases of our common units made by us or on our behalf in the quarter ended March 31, 2018:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Not Purchased as Part of Publicly Announced Plans or Programs [1]	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs
January 2018	1,182,745	$ 20.06	1,182,745	—
February 2018	—	—	—	—
March 2018	—	—	—	—

(1) The units reported in this column represent purchases settled during the quarter ended March 31, 2018 relating to our purchases of units in open-market transactions to meet our obligations under our equity incentive plans for employees, officers and directors.

ITEM 5. OTHER INFORMATION

We are including information in this “Part II - Item 5. Other Information” in order to: (i) file Exhibit 99.1 hereto to replace in its entirety (a) the section under the heading “Material U.S. Federal Income Tax Considerations” that appears in the prospectus supplement we filed with the SEC on May 10, 2017 (the “ATM Prospectus”) and (b) the section under the heading “Material U.S. Federal Income Tax Consequences” that appears in the Registration Statement on Form S-3 (Registration File No. 333- 219224) we filed with the SEC on July 11, 2017 (the "DRIP Registration Statement"), in each case to provide updated disclosure regarding the material tax considerations associated with our operations and the purchase, ownership and disposition of our common units and (ii) provide the legal opinion of Vinson & Elkins L.L.P. relating to certain tax matters in connection with the ATM Prospectus and the DRIP Registration Statement, a copy of which is filed as Exhibit 8.1 hereto.

ITEM 6. EXHIBITS

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

Exhibit Number	Description
2.1	Contribution Agreement, dated as of January 15, 2018, by and among USA Compression Partners, LP, Energy Transfer Partners, L.P., Energy Transfer Partners GP, L.P., ETC Compression, LLC, and solely for certain purposes therein, Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 2.1 to the Current Report of For 8-K filed January 16, 2018)
2.2	Purchase Agreement, dated as of January 15, 2018, by and among USA Compression Holdings, LLC, Energy Transfer Equity, L.P., Energy Transfer Partners, L.L.C., and solely for certain purposes therein R/C IV USACP Holdings, L.P. and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed January 16, 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	Fourth Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. dated as of April 28, 2017 (incorporated by reference to Exhibit 3.4 to the Current Report on Form 8-K filed April 28, 2017)
3.5	Amendment No. 1, dated November 16, 2017, to the Fourth Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated as of April 28, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 16, 2017)
3.6	Amendment No. 2, dated as of April 25, 2018, to Fourth Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated as of April 28, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 25, 2018)
8.1*	Opinion of Vinson & Elkins L.L.P. relating to tax matters
10.1	Registration Rights Agreement, dated as of April 2, 2018, by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P., USA Compression Partners, LP and USA Compression Holdings, LLC. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 3, 2018)
10.2	Transition Services Agreement, dated as of April 2, 2018, by and among USA Compression Partners, LP, CDM Resource Management LLC, CDM Environmental & Technical Services LLC and Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed April 3, 2018)
12.1*	Computation of Ratio of Earnings to Fixed Charges
23.1*	Consent of Vinson & Elkins L.L.P. (included in Exhibit 8.1 hereto)
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
99.1*	Material U.S. Federal Income Tax Consequences
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith.
**	Furnished herewith.

SIGNATURE

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

ENERGY TRANSFER PARTNERS, L.P.

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

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

Date: May 10, 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)

Vinson&Elkins

Exhibit 8.1

May 10, 2018

Energy Transfer Partners, L.P.
8111 Westchester Drive, Suite 600
Dallas, Texas 75225

Re: Energy Transfer Partners, L.P. Form 10-Q

Ladies and Gentlemen:

We have acted as counsel for Energy Transfer Partners, L.P. (the "***Partnership***"), a Delaware limited partnership, with respect to certain legal matters related to (i) the prospectus supplement dated May 10, 2017 and related prospectus, forming a part of the registration statement on Form S-3, No. 333-212962, which was declared effective on October 20, 2016 (the "***ATM Prospectus***"), (ii) the registration statement on Form S-3, No. 333-219224, dated July 11, 2017 (the "***DRIP Registration Statement***") and (iii) the Exhibit 99.1 filed as an exhibit to the 10-Q filed on or about the date hereof (the "***Updated Tax Disclosure***" together with the ATM Prospectus and the DRIP Registration Statement, the "***Applicable Filings***"). In connection with the Applicable Filings, we are issuing this opinion.

This opinion is based on various facts and assumptions, and is conditioned upon certain representations made by the Partnership as to factual matters through a certificate of an officer of the Partnership (the "***Officer's Certificate***"). In addition, this opinion is based upon the factual representations of the Partnership concerning its business, properties and governing documents as set forth in the Applicable Filings.

In our capacity as counsel to the Partnership, we have made such legal and factual examinations and inquiries, including an examination of originals or copies certified or otherwise identified to our satisfaction of such documents, corporate records and other instruments, as we have deemed necessary or appropriate for purposes of this opinion. In our examination, we have assumed the authenticity of all documents submitted to us as originals, the genuineness of all signatures thereon, the legal capacity of natural persons executing such documents and the conformity to authentic original documents of all documents submitted to us as copies. For the purpose of our opinion, we have not made an independent investigation or audit of the facts set forth in the above-referenced documents or in the Officer's Certificate. In addition, in rendering this opinion we have assumed the truth and accuracy of all representations and statements made to us which are qualified as to knowledge or belief, without regard to such qualification.

We hereby confirm that all statements of legal conclusions contained in the discussion in the ATM Prospectus under the caption "Material U.S. Federal Income Tax Considerations" and the DRIP Registration Statement under the caption "Material U.S. Federal Income Tax Consequences," both, as replaced in their entirety by the Updated Tax Disclosure, (collectively, the "***Covered Discussions***") constitute the opinion of Vinson & Elkins L.L.P. with respect to the matters set forth therein as of the date hereof, subject to the assumptions, qualifications, and limitations set forth therein. This opinion is based on various statutory provisions, regulations promulgated thereunder and interpretations thereof by the Internal Revenue Service and the courts having jurisdiction over such matters, all of which are subject to change either prospectively or retroactively. Also, any variation or difference in the facts from those set forth in the representations described above, including in the Applicable Filings and the Officer's Certificate, may affect the conclusions stated herein.

No opinion is expressed as to any matter not discussed in the Covered Discussions. We are opining herein only as to the federal income tax matters described above, and we express no opinion with respect to the applicability to, or the effect on, any transaction or other federal laws, foreign laws, the laws of any state or any other jurisdiction or as to any matters of municipal law or the laws of any other local agencies within any state.

This opinion is rendered to you as of the date hereof, and we undertake no obligation to update this opinion subsequent to the date hereof. This opinion is furnished to you and may be relied on by you in connection with the transactions set forth in the ATM Prospectus and the DRIP Registration Statement. In addition, this opinion may be relied on by persons entitled to rely on it pursuant to applicable provisions of federal securities law, including persons purchasing common units pursuant to the ATM Prospectus

Vinson & Elkins LLP Attorneys at Law
Austin Beijing Dallas Dubai Hong Kong Houston London Moscow New York
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Houston, TX 77002-6760
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and the DRIP Registration Statement. However, this opinion may not be relied upon for any other purpose or furnished to, assigned to, quoted to or relied upon by any other person, firm or other entity, for any purpose, without our prior written consent.

We hereby consent to the filing of this opinion of counsel as Exhibit 8.1 to the Form 10-Q, to the incorporation by reference of this opinion of counsel into the DRIP Registration Statement and the ATM Prospectus and to the reference to our firm in the Applicable Filings. In giving such consent, we do not admit that we are within the category of persons whose consent is required under Section 7 of the Securities Act of 1933, as amended.

Very truly yours,

/s/ VINSON & ELKINS L.L.P.

Vinson & Elkins L.L.P.

Exhibit 12.1

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

	Three Months Ended March 31, 2018	
	Energy Transfer Partners, L.P. (consolidated)	Sunoco Logistics Partners Operations L.P.
Fixed Charges:		
Interest expense, net	$ 346	$ 40
Capitalized interest	80	54
Interest charges included in rental expense	3	2
Total fixed charges	429	96
Series A and B preferred unit distributions	24	—
Total fixed charges and preferred unit distributions	453	96
Earnings:		
Income before income tax expense (benefit)	839	235
Less: equity in earnings (losses) of unconsolidated affiliates	(72)	48
Total earnings	911	187
Add:		
Fixed charges	429	96
Amortization of capitalized interest	5	1
Distributed income of equity investees	106	38
Less:		
Interest capitalized	(80)	(54)
Income available for fixed charges	$ 1,371	$ 268
Ratio of earnings to fixed charges	3.20	2.79
Ratio of earnings to fixed charges and preferred unit distributions	3.03	2.79

Exhibit 31.1

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

I, Kelcy L. Warren, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2018

/s/ Kelcy L. Warren

Kelcy L. Warren
Chief Executive Officer

Exhibit 31.2

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

I, Thomas E. Long, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 10, 2018

/s/ Thomas E. Long

Thomas E. Long
Chief Financial Officer

Exhibit 32.1

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

In connection with the quarterly report of Energy Transfer Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended March 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kelcy L. Warren, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: May 10, 2018

/s/ Kelcy L. Warren

Kelcy L. Warren

Chief Executive Officer

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

Exhibit 32.2

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

In connection with the quarterly report of Energy Transfer Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended March 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Thomas E. Long, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: May 10, 2018

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

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

Exhibit 99.1

MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

This section summarizes the material U.S. federal income tax consequences that may be relevant to prospective unitholders and is based upon current provisions of the U.S. Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed U.S. Treasury regulations thereunder (the "Treasury Regulations"), and current administrative rulings and court decisions, all of which are subject to change. Changes in these authorities may cause the federal income tax consequences to a prospective unitholder to vary substantially from those described below, possibly on a retroactive basis. Unless the context otherwise requires, references in this section to "we" "us" or "the Partnership" are references to Energy Transfer Partners, L.P. and its subsidiaries.

Legal conclusions contained in this section, unless otherwise noted, are the opinion of Vinson & Elkins L.L.P. and are based on the accuracy of representations made by us to them for this purpose. However, this section does not address all federal income tax matters that may affect us or our unitholders, such as the application of the alternative minimum tax. This section also does not address local taxes, state taxes, non-U.S. taxes, or other taxes that may be applicable, except to the limited extent that such tax considerations are addressed below under "-State, Local and Other Tax Considerations." Furthermore, this section focuses on unitholders who are individual citizens or residents of the United States (for federal income tax purposes), who have the U.S. dollar as their functional currency, who use the calendar year as their taxable year, who purchase common units in this offering, who do not materially participate in the conduct of our business activities and who hold such common units as capital assets (typically, property that is held for investment). This section has limited applicability to corporations (including other entities treated as corporations for federal income tax purposes), partnerships (including other entities treated as partnerships for federal income tax purposes), estates, trusts, non-resident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt entities, non-U.S. persons, individual retirement accounts ("IRAs"), employee benefit plans, real estate investment trusts or mutual funds.

Accordingly, we encourage each prospective unitholder to consult the unitholder's own tax advisor in analyzing the federal, state, local and non-U.S. tax consequences that are particular to that unitholder resulting from ownership or disposition of our common units and potential changes in applicable tax laws.

We are relying on the opinions and advice of Vinson & Elkins L.L.P. with respect to the matters described herein. An opinion of counsel represents only that counsel's best legal judgment and does not bind the Internal Revenue Service (the "IRS") or a court. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any such contest of the matters described herein may materially and adversely impact the market for our common units and the prices at which our common units trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution. Furthermore, the tax consequences of an investment in us may be significantly modified by future legislative or administrative changes or court decisions, which may be retroactively applied.

For the reasons described below, Vinson & Elkins L.L.P. has not rendered an opinion with respect to the following federal income tax issues:

- the treatment of a unitholder whose common units are the subject of a securities loan (e.g., a loan to a short seller to cover a short sale of common units) (please read "-Tax Consequences of Unit Ownership-Treatment of Securities Loans");
- whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read "-Disposition of Common Units-Allocations Between Transferors and Transferees");
- whether our method for taking into account Section 743 adjustments is sustainable in certain cases (please read "-Tax Consequences of Unit Ownership-Section 754 Election" and "-Uniformity of Common Units"); and
- whether our use of simplifying conventions for making adjustments to "book" basis and relevant allocations is permitted by existing Treasury Regulations (please read "-Tax Consequences of Unit Ownership-Allocation of Income, Gain, Loss and Deduction" and "-Uniformity of Units").

Taxation of the Partnership

Partnership Status

We are treated as a partnership for U.S. federal income tax purposes and, therefore, subject to the discussion below under "-Administrative Matters-Information Returns and Audit Procedures", generally will not be liable for entity-level federal income taxes. Instead, as described below, each of our unitholders will take into account its respective share of our items of income, gain, loss and deduction in computing its federal income tax liability as if the unitholder had earned such income directly, even if we make no cash distributions to the unitholder. Distributions we make to a unitholder will not give rise to income or gain taxable to such unitholder, unless the amount of cash distributed exceeds the unitholder's adjusted tax basis in its common units. Please read "-Tax Consequences of Unit Ownership-Treatment of Distributions" and "-Disposition of Common Units").

Section 7704 of the Code generally provides that publicly-traded partnerships will be treated as a corporations for federal income tax purposes. However, if 90% or more of a partnership's gross income for every taxable year it is publicly-traded consists of "qualifying income," the partnership may continue to be treated as a partnership for federal income tax purposes (the "Qualifying Income Exception"). Qualifying income includes, (i) interest, (ii) dividends, (iii) real property rents within the meaning of Section 856(d) of the Code, as modified by Section 7704(d)(3) of the Code, (iv) gains from the sale or other disposition of real property, (v) income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof) or the marketing of any "mineral or natural resource", and (vi) gains from the sale or other disposition of capital assets (or property described in Section 1231(b) of the Code) held for the production of income that otherwise constitutes qualifying income. We estimate that less than 3% of our current gross income is not qualifying income; however, this estimate could change from time to time.

No ruling has been or will be sought from the IRS with respect to our classification as a partnership for federal income tax purposes or as to the classification of our partnership and limited liability company operating subsidiaries. Instead we have relied on the opinion of Vinson & Elkins L.L.P. that, based upon the Code, existing Treasury Regulations, published revenue rulings and court decisions and representations described below, the Partnership and each of our partnership and limited liability company operating subsidiaries, other than those that have been identified as corporations to Vinson & Elkins L.L.P., will be classified as a partnerships or disregarded as an entity separate from us for federal income tax purposes.

Vinson & Elkins L.L.P. is of the opinion that we will be treated as a partnership for federal income tax purposes and each of our partnership and limited liability company operating subsidiaries, other than those that have been identified as corporations to Vinson & Elkins L.L.P., will be treated as a partnership or will be disregarded as an entity separate from us. In rendering its opinion, Vinson & Elkins L.L.P. has relied on factual representations made by us and our general partner, including, without limitation:

(a) Neither we nor any of our partnership or limited liability company operating subsidiaries, other than those that have been identified as corporations to Vinson & Elkins L.L.P., has elected or will elect to be treated as a corporation for federal income tax purposes;

(b) For each taxable year since and including the year of our initial public offering, more than 90% of our gross income has been and will be income of a character that Vinson & Elkins L.L.P. has opined is "qualifying income" within the meaning of Section 7704(d) of the Code; and

(c) Each hedging transaction that we treat as resulting in qualifying income has been and will be appropriately identified as a hedging transaction pursuant to applicable Treasury Regulations, and has been and will be associated with oil, natural gas or products thereof that are held or to be held by us in activities that Vinson & Elkins L.L.P. has opined or will opine result in qualifying income.

We believe that these representations are true and will be true in the future.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as transferring all of our assets, subject to all of our liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception in return for stock in that corporation and then as distributing that stock to our unitholders in liquidation of their interests in us. This deemed contribution and liquidation should not result in the recognition of taxable income by our unitholders or us so long as the aggregate amount of our liabilities does not exceed the adjusted tax basis of our assets. Thereafter, we would be treated as an association taxable as a corporation for federal income tax purposes.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative or legislative action or judicial interpretation at any time. From time to time, members of the U.S. Congress have proposed and considered substantive changes to the existing federal income tax laws that would affect publicly-traded partnerships. One such legislative proposal would have eliminated the Qualifying Income Exception upon which we rely for our treatment as a partnership for federal income tax purposes.

In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income (the "Final Regulations") within the meaning of Section 7704 of the Code were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to qualify as a publicly traded partnership.

It is possible that a change in law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our common units. If for any reason we are taxable as a corporation in any taxable year, our items of income, gain, loss and deduction would be taken into account by us in determining the amount of our liability for federal income tax, rather than being passed through to our unitholders.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our unitholders.

Our taxation as a corporation would materially reduce the cash available for distribution to unitholders and thus would likely substantially reduce the value of our common units. Any distribution made to a unitholder at a time when we are treated as a corporation would be (i) a taxable dividend to the extent of our current or accumulated earnings and profits, then (ii) a nontaxable return of capital to the extent of the unitholder's adjusted tax basis in its common units (determined separately for each unit), and thereafter (iii) taxable capital gain. In addition, our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or because our general partner makes an election for us to be taxed as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The remainder of this discussion is based on the opinion of Vinson & Elkins L.L.P. that we will be treated as a partnership for federal income tax purposes.

Tax Consequences of Unit Ownership

Limited Partner Status

Unitholders of the Partnership who are admitted as limited partners of the partnership will be treated as partners of the Partnership for federal income tax purposes. In addition, assignees who have executed and delivered transfer applications, and are awaiting admission as limited partners, and unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of the Partnership for federal income tax purposes.

As there is no direct or indirect controlling authority addressing assignees of common units who are entitled to execute and deliver transfer applications and thereby become entitled to direct the exercise of attendant rights, but who fail to execute and deliver transfer applications, Vinson & Elkins L.L.P.'s opinion does not extend to these persons. Furthermore, a purchaser or other transferee of common units who does not execute and deliver a transfer application may not receive some federal income tax information or reports furnished to record holders of common units unless the common units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application for those common units.

For a discussion related to the risks of losing partner status as a result of securities loans, please read "-Treatment of Securities Loans." Unitholders who are not treated as partners in us as described above are urged to consult their own tax advisors with respect to the tax consequences applicable to them under their particular circumstances.

Flow-Through of Taxable Income

Subject to the discussion below under "-Entity-Level Collections of Unitholder Taxes" and "-Administrative Matters-Information Returns and Audit Procedures", and, with respect to payments we may be required to make on behalf of our unitholders, we will not pay any federal income tax. Rather, each unitholder will be required to report on its federal income tax return each year its share of our income, gains, losses and deductions for our taxable year or years ending with or within its taxable year. Except as described below under "-Treatment of Distributions," participants in our distribution reinvestment plan ("DRIP") will be allocated taxable income and loss in the same manner as all other unitholders even if they elect to reinvest their entire cash distribution. Consequently, we may allocate income to a unitholder even if that unitholder has not received a cash distribution.

Basis of Common Units

A unitholder's tax basis in its common units initially will be the amount paid or treated as paid for those common units increased by the unitholder's initial allocable share of our liabilities. That basis generally will be (i) increased by the unitholder's share of our income and any increases in such unitholder's share of our liabilities, and (ii) decreased, but not below zero, by the amount of all distributions to the unitholder, the unitholder's share of our losses, any decreases in its share of our liabilities, and the amount of any excess business interest allocated to the unitholder. The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all of those interests.

Treatment of Distributions

Distributions made by us to a unitholder generally will not be taxable to the unitholder, unless such distributions are of cash or marketable securities that are treated as cash and exceed the unitholder's tax basis in its common units, in which case the unitholder generally will recognize gain taxable in the manner described below under "-Disposition of Common Units."

If, and to the extent that, a unitholder participates in our DRIP, such unitholder will receive common units in lieu of all or a portion of any cash distributions it would otherwise receive from us. The tax consequences of such participation are generally expected to be the same to the DRIP participants as if they had received their cash distributions paid to the unitholders and then used these cash distributions to purchase additional common units either from us or on the open market, depending on how we instruct the DRIP administrator to reinvest the distributions subject to our distribution reinvestment plan. If a participant in our DRIP is deemed to have purchased additional common units at a discount, it may be necessary to allocate income to such participant in our DRIP in order to preserve the uniformity of our units. Accordingly, a participant in our DRIP may recognize income in the amount of the discount.

Any reduction in a unitholder's share of our "nonrecourse liabilities" (liabilities for which no partner bears the economic risk of loss) will be treated as a distribution by us of cash to that unitholder. A decrease in a unitholder's percentage interest in us because of our issuance of additional common units may decrease such unitholder's share of our nonrecourse liabilities. For purposes of the foregoing, a unitholder's share of our nonrecourse liabilities generally will be based upon such unitholder's share of the unrealized appreciation (or depreciation) in our assets, to the extent thereof, with any excess nonrecourse liabilities allocated based on the unitholder's share of our profits. Please read "-Disposition of Common Units."

A non-pro rata distribution of money or property (including a deemed distribution as a result of the reallocation of our nonrecourse liabilities described above) may cause a unitholder to recognize ordinary income if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture and substantially appreciated "inventory items," both as defined in Section 751 of the Code ("Section 751 Assets"). To the extent of such reduction, the unitholder would be deemed to receive its proportionate share of the Section 751 Assets and exchange such assets with us in return for a portion of the non-pro rata distribution. This deemed exchange will generally result in the unitholder's recognition of ordinary income in an amount equal to the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis (typically zero) in the Section 751 Assets deemed to be relinquished in the exchange.

Limitations on Deductibility of Losses

A unitholder may not be entitled to deduct the full amount of loss we allocate to it because its share of our losses will be limited to the lesser of (i) the unitholder's adjusted tax basis in its common units, and (ii) in the case of a unitholder that is an individual, estate, trust or certain types of closely-held corporations, the amount for which the unitholder is considered to be "at risk" with respect to our activities. A unitholder will be at risk to the extent of its adjusted tax basis in its common units, reduced by (1) any portion of that basis attributable to the unitholder's share of our nonrecourse liabilities, (2) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or similar arrangement, and (3) any amount of money the unitholder borrows to acquire or hold its common units, if the lender of those borrowed funds owns an interest in us, is related to another unitholder or can look only to the common units for repayment. A unitholder subject to the at risk limitation must recapture losses deducted in previous years to the extent that distributions (including distributions deemed to result from a reduction in a unitholder's share of nonrecourse liabilities) cause the unitholder's at risk amount to be less than zero at the end of any taxable year.

Losses disallowed to a unitholder or recaptured as a result of the basis or at risk limitations will carry forward and will be allowable as a deduction in a later year to the extent that the unitholder's adjusted tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon a taxable disposition of our common units, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but not losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain can no longer be used, and will not be available to offset a unitholder's salary or active business income.

In addition to the basis and at risk limitations, passive activity loss limitations generally limit the deductibility of losses incurred by individuals, estates, trusts, some closely held corporations and personal service corporations from "passive activities" (generally, trade or business activities in which the taxpayer does not materially participate). The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses we generate will be available to offset only passive income generated in the future and will not be available to offset income from other passive activities or investments, including any dividend or interest income we derive from our other investments (including investments in other publicly traded partnerships) or from a unitholder's other investments (including investments in other publicly traded partnerships, such as ETE), or salary or active business income. Passive losses that are not deductible because they exceed a common unitholder's share of income we generate may be deducted in full when the unitholder disposes of all of its units in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk and basis limitations.

Notwithstanding the forgoing, the IRS could take the position that for purposes of applying the passive loss limitation rules to tiered publicly traded partnerships, such as ETE and us, the related entities are treated as one publicly traded partnership. In that case, any passive losses we generate would be available to offset income from a unitholder's investments in ETE. However, passive losses that are not deductible because they exceed a unitholder's share of income we generate would not be deductible in full until a unitholder disposes of his entire investment in both us and ETE in a fully taxable transaction with an unrelated party.

For taxpayers other than corporations in taxable years beginning after December 31, 2017, and before January 1, 2026, an "excess business loss" limitation further limits the deductibility of losses by such taxpayers. An excess business loss is the excess (if any) of a taxpayer's aggregate deductions for the taxable year that are attributable to the trades or businesses of such taxpayer (determined without regard to the excess business loss limitation) over the aggregate gross income or gain of such taxpayer for the taxable year that is attributable to such trades or businesses plus a threshold amount. The threshold amount is equal to $250,000 or $500,000 for taxpayers filing a joint return. Disallowed excess business losses are treated as a net operating loss carryover to the following tax year. Any losses we generate that are allocated to a unitholder and not otherwise limited by the basis, at risk, or passive loss limitations will be included in the determination of such unitholder's aggregate trade or business deductions. Consequently, any losses we generate that are not otherwise limited will only be available to offset a unitholder's other trade or business income plus an amount of non-trade or business income equal to the applicable threshold amount. Thus, except to the extent of the threshold amount, our losses that are not otherwise limited may not offset a unitholder's non-trade or business income (such as salaries, fees, interest, dividends and capital gains). This excess business loss limitation will be applied after the passive activity loss limitation.

Limitations on Interest Deductions

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, our deduction for this "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. This limitation is first applied at the partnership level and any deduction for business interest is taken into account in determining our non-separately stated taxable income or loss. Then, in applying this business interest limitation at the partner level, the adjusted taxable income of each of our unitholders is determined without regard to such unitholder's distributive share of any of our items of income, gain, deduction, or loss and is increased by such unitholder's distributive share of our excess taxable income, which is generally equal to the excess of 30% of our adjusted taxable income over the amount of our deduction for business interest for a taxable year.

To the extent our deduction for business interest is not limited, we will allocate the full amount of our deduction for business interest among our unitholders in accordance with their percentage interests in us. To the extent our deduction for business interest is limited, the amount of any disallowed deduction for business interest will also be allocated to each unitholder in accordance with their percentage interest in us, but such amount of "excess business interest" will not be currently deductible. Subject to certain limitations and adjustments to a unitholder's basis in its common units, this excess business interest may be carried forward and deducted by a unitholder in a future taxable year.

In addition to this limitation on the deductibility of a partnership's business interest, the deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness allocable to property held for investment;
- interest expense allocated against portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent allocable against portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income. Net investment income does not include qualified dividend income (if applicable) or gains attributable to the disposition of property held for investment. A unitholder's share of a publicly-traded partnership's portfolio income and, according to the IRS, net passive income will be treated as investment income for purposes of the investment interest expense limitation.

Entity-Level Collections of Unitholder Taxes

If we are required or elect under applicable law to pay any federal, state, local or non-U.S. tax on behalf of any current or former unitholder or our general partner, our partnership agreement authorizes us to treat the payment as a distribution of cash to the relevant unitholder or general partner. Where the tax is payable on behalf of all unitholders or we cannot determine the specific unitholder on whose behalf the tax is payable, our partnership agreement authorizes us to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of common units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of a unitholder, in which event the unitholder may be entitled to claim a refund of the overpayment amount. Please read "-Administrative Matters-Information Returns and Audit Procedures". Each unitholder is urged to consult its tax advisor to determine the consequences to them of any tax payment we make on its behalf.

Allocation of Income, Gain, Loss and Deduction

After giving effect to special allocation provisions with respect to our other classes of units, our items of income, gain, loss and deduction generally will be allocated amongst our common unitholders and our general partner in accordance with their percentage interests in us. At any time that incentive distributions are made to our general partner, gross income will be allocated to the recipients to the extent of such distributions.

Specified items of our income, gain, loss and deduction will be allocated under Section 704(c) of the Code (or the principles of Section 704(c) of the Code) to account for any difference between the adjusted tax basis and fair market value of our assets at the time such assets are contributed to us and at the time of any subsequent offering of our common units (a "Book-Tax Disparity"). As a result, the federal income tax burden associated with any Book-Tax Disparity immediately prior to an offering will be borne by our partners holding interests in us prior to such offering. In addition, items of recapture income will be specially allocated to the extent possible (subject to the limitations described above) to the unitholder who was allocated the deduction giving rise to that recapture income in order to minimize the recognition of ordinary income by other unitholders.

It may not be administratively feasible to make the relevant adjustments to "book" basis and the relevant Section 704(c) allocations separately each time we issue units, particularly in the case of small or frequent unit issuances. If that is the case, we may use simplifying conventions to make those adjustments and allocations, which may include the aggregation of certain issuances of units. Our counsel, Vinson & Elkins, L.L.P., is unable to opine as to the validity of such conventions.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Code to eliminate a Book-Tax Disparity, will be given effect for federal income tax purposes in determining a unitholder's share of an item of income, gain, loss or deduction only if the allocation has "substantial economic effect." In any other case, a unitholder's share of an item will be determined on the basis of the unitholder's interest in us, which will be determined by taking into account all the facts and circumstances, including (i) the unitholder's relative contributions to us, (ii) the interests of all the partners in profits and losses, (iii) the interest of all the partners in cash flow and (iv) the rights of all the partners to distributions of capital upon liquidation. Vinson & Elkins L.L.P. is of the opinion that, with the exception of the issues described in "- Section 754 Election" and "- Disposition of Common Units - Allocations Between Transferors and Transferees," allocations of income, gain, loss or deduction under our partnership agreement generally will be given effect for federal income tax purposes.

Treatment of Securities Loans

A unitholder whose common units are the subject of a securities loan (for example, a loan to a "short seller" to cover a short sale of common units) may be treated as having disposed of those common units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss as a result of such deemed disposition. As a result, during this period (i) any of our income, gain, loss or deduction allocated to those common units would not be reportable by the lending unitholder, and (ii) any cash distributions received by the lending unitholder as to those common units may be treated as ordinary taxable income.

Due to a lack of controlling authority, Vinson & Elkins L.L.P. has not rendered an opinion regarding the tax treatment of a unitholder that enters into a securities loan with respect to its common units. A unitholder desiring to assure its status as a partner and avoid the risk of income recognition from a loan of its common units is urged to modify any applicable brokerage account agreements to prohibit its brokers from borrowing and lending its common units. The IRS has announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please read "-Disposition of Common Units-Recognition of Gain or Loss."

Tax Rates

Under current law, the highest marginal federal income tax rates for individuals applicable to ordinary income and long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) are 37% and 20%, respectively. These rates are subject to change by new legislation at any time.

In addition, a 3.8% net investment income tax applies to certain net investment income earned by individuals, estates, and trusts. For these purposes, net investment income generally includes a unitholder's allocable share of our income and gain realized by a unitholder from a sale of common units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income from all investments, or (ii) the amount by which the unitholder's modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if the unitholder is married and filing separately) or $200,000 (if the unitholder is unmarried or in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

For taxable years beginning after December 31, 2017 and ending on or before December 31, 2025, an individual unitholder is entitled to a deduction equal to 20% of his or her allocable share of our "qualified business income." For purposes of this deduction, our "qualified business income" is equal to the sum of:

- the net amount of our U.S. items of income, gain, deduction, and loss to the extent such items are included or allowed in the determination of taxable income for the year, *excluding*, however, certain specified types of passive investment income (such as capital gains and dividends) and certain payments made to the unitholder for services rendered to the Partnership; and
- any gain recognized upon a disposition of our common units to the extent such gain is attributable to Section 751 Assets, such as depreciation recapture and our "inventory items," and is thus treated as ordinary income under Section 751 of the Code.

Section 754 Election

We have made the election permitted by Section 754 of the Code that permits us to adjust the tax basis in each of our assets as to specific purchasers of our common units under Section 743(b) of the Code to reflect the unit purchase price upon subsequent purchases of common units. That election is irrevocable without the consent of the IRS. The Section 743(b) adjustment separately applies to a unitholder who purchases common units from another unitholder based upon the values and adjusted tax basis of each of our assets at the time of the relevant unit purchase, and the adjustment will reflect the purchase price paid. The Section 743(b) adjustment does not apply to a person who purchases common units directly from us. For purposes of this discussion, a unitholder's basis in our assets will be considered to have two components: (1) its share of the tax basis in our assets as to all unitholders and (2) its Section 743(b) adjustment to that tax basis (which may be positive or negative).

Under our partnership agreement, we are authorized to take a position to preserve the uniformity of common units even if that position is not consistent with applicable Treasury Regulations. A literal application of Treasury Regulations governing a Section 743(b) adjustment attributable to properties depreciable under Section 167 of the Code may give rise to differences in the taxation of unitholders purchasing common units from us and unitholders purchasing from other unitholders. If we have any such properties, we intend to adopt methods employed by other publicly traded partnerships to preserve the uniformity of common units, even if inconsistent with existing Treasury Regulations, and Vinson & Elkins L.L.P. has not opined on the validity of this approach. Please read "-Uniformity of Common Units."

The IRS may challenge the positions we adopt with respect to depreciating or amortizing the Section 743(b) adjustment to preserve the uniformity of common units due to the lack of controlling authority. Because a unitholder's adjusted tax basis for its common units is reduced by its share of our items of deduction or loss, any position we take that understates deductions will overstate a unitholder's tax basis in its common units, and may cause the unitholder to understate gain or overstate loss on any sale of such common units. Please read "- Disposition of Common Units - Recognition of Gain or Loss." If a challenge to such treatment were sustained, the gain from the sale of common units may be increased without the benefit of additional deductions.

The calculations involved in the Section 754 election are complex and are made on the basis of assumptions as to the value of our assets and other matters. The IRS could seek to reallocate some or all of any Section 743(b) adjustment we allocated to our assets subject to depreciation to goodwill or nondepreciable assets. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure any unitholder that the determinations we make will not be successfully challenged by the IRS or that the resulting deductions will not be reduced or disallowed altogether. Should the IRS require a different tax basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of common units may be allocated more income than it would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in its tax return its share of our income, gain, loss and deduction for each taxable year ending within or with its taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of its common units following the close of our taxable year but before the close of its taxable year must include its share of our income, gain, loss and deduction in income for its taxable year, with the result that it will be required to include in income for its taxable year its share of more than twelve months of our income, gain, loss and deduction. Please read "-Disposition of Common Units-Allocations Between Transferors and Transferees."

Tax Basis, Depreciation and Amortization

The tax basis of each of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation deductions previously taken, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of its interest in us. Please read "-Tax Consequences of Unit Ownership-Allocation of Income, Gain, Loss and Deduction" and "-Disposition of Common Units - Recognition of Gain or Loss."

The costs we incur in offering and selling our common units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. While there are uncertainties regarding the classification of certain costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us, the underwriting discounts and commissions we incur will be treated as syndication expenses. Please read "Disposition of Common Units - Recognition of Gain or Loss."

We are allowed a first-year bonus depreciation deduction equal to 100% of the adjusted basis of certain depreciable property acquired and placed in service after September 27, 2017 and before January 1, 2023. For property placed in service during subsequent years, the deduction is phased down by 20% per year until December 31, 2026. This depreciation deduction applies to both new and used property. However, use of the deduction with respect to used property is subject to certain anti-abuse restrictions, including the requirement that the property be acquired from an unrelated party. We can elect to forgo the depreciation bonus and use the alternative depreciation system for any class of property for a taxable year. Under a transition rule, we can also elect to apply a 50% bonus depreciation deduction instead of the 100% deduction for our first taxable year ending after September 27, 2017.

Coal Income

Section 631 of the Code provides special rules by which gains or losses on the sale of coal may be treated, in whole or in part, as gains or losses from the sale of property used in a trade or business under Section 1231 of the Code. Specifically, if the owner of coal held for more than one year disposes of that coal under a contract by virtue of which the owner retains an economic interest in the coal under Section 631(c) of the Code, the gain or loss realized will be treated under Section 1231 of the Code as gain or loss from property used in a trade or business. Section 1231 gains and losses may be treated as capital gains and losses. Please read "-Sales of Coal Reserves or Timberland." In computing such gain or loss, the amount realized is reduced by the adjusted depletion basis in the coal, determined as described in "-Coal Depletion."

For purposes of Section 631(c) of the Code, the coal generally is deemed to be disposed of on the day on which the coal is mined. Further, Treasury Regulations promulgated under Section 631 of the Code provide that advance royalty payments may also be treated as proceeds from sales of coal to which Section 631 of the Code applies and, therefore, such payment may be treated as capital gain under Section 1231 of the Code. However, if the right to mine the related coal expires or terminates under the contract that provides for the payment of advance royalty payments or such right is abandoned before the coal has been mined, we may, pursuant to the Treasury Regulations, file an amended return that reflects the payments attributable to unmined coal as ordinary income and not as received from the sale of coal under Section 631 of the Code.

Our royalties from coal leases generally will be treated as proceeds from sales of coal to which Section 631 of the Code applies. Accordingly, the difference between the royalties paid to us by the lessees and the adjusted depletion basis in the extracted coal generally will be treated as gain from the sale of property used in a trade or business, which may be treated as capital gain under Section 1231 of the Code. Please read “-Sales of Coal Reserves or Timberland.” Our royalties that do not qualify under Section 631(c) of the Code generally will be taxable as ordinary income in the year of sale.

Coal Depletion

In general, we are entitled to depletion deductions with respect to coal mined from the underlying mineral property. Subject to the limitations on the deductibility of losses discussed above, we generally are entitled to the greater of cost depletion limited to the basis of the property or percentage depletion. The percentage depletion rate for coal is 10%. If Section 631(c) of the Code applies to the disposition of the coal, however, we are not eligible for percentage depletion. Please read “-Coal Income.”

Depletion deductions we claim generally will reduce the tax basis of the underlying mineral property. Depletion deductions can, however, exceed the total tax basis of the mineral property. The excess of our percentage depletion deductions over the adjusted tax basis of the property at the end of the taxable year is subject to tax preference treatment in computing the alternative minimum tax, the consequences of which are not addressed herein. In addition, a corporate unitholder’s allocable share of the amount allowable as a percentage depletion deduction for any property will be reduced by 20% of the excess, if any, of that partner’s allocable share of the amount of the percentage depletion deductions for the taxable year over the adjusted tax basis of the mineral property as of the close of the taxable year.

Oil and Natural Gas Depletion

Subject to the limitations on deductibility of losses discussed above (please read “-Tax Consequences of Unit Ownership-Limitations on Deductibility of Losses”), unitholders may be entitled to depletion deductions with respect to our oil and natural gas royalty interests. The deduction is equal to the greater of cost depletion limited to the basis of the property or (if otherwise allowable) percentage depletion.

Percentage depletion is generally available with respect to unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas or derivative products or the operation of a major refinery. Percentage depletion is calculated as an amount generally equal to 15% of the unitholder’s gross income from the oil and gas property for the taxable year. A unitholder generally may deduct percentage depletion only to the extent the unitholder’s average daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. A limitation equal to the lower of 65% of taxable income or 100% of taxable income from the property further limits the deduction for the taxable year.

All or a portion of any gain recognized by a unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the unitholder of some or all of his common units may be taxed as ordinary income to the extent of recapture of oil and gas depletion.

Although the Code requires each unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each unitholder with information relating to this computation for federal income tax purposes. Each unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the underlying property for depletion and other purposes.

Timber Income

Section 631 of the Code provides special rules by which gains or losses on the sale of timber may be treated, in whole or in part, as gains or losses from the sale of property used in a trade or business under Section 1231 of the Code. Specifically, if the owner of timber (including a holder of a contract right to cut timber) held for more than one year disposes of that timber under any contract by virtue of which the owner retains an economic interest in the timber under Section 631(b) of the Code, the gain or loss realized will be treated under Section 1231 of the Code as gain or loss from property used in a trade or business. Section 1231 gains and losses may be treated as capital gains and losses. Please read “-Sales of Coal Reserves or Timberland.” In computing such gain or loss, the amount realized is reduced by the adjusted basis in the timber, determined as described in “-Timber Depletion.” For purposes of Section 631(b) of the Code, the timber generally is deemed to be disposed of on the day on which the timber is cut (which is generally deemed to be the date when, in the ordinary course of business, the quantity of the timber cut is first definitely determined).

Proceeds we receive from standing timber sales generally will be treated as sales of timber to which Section 631 of the Code applies. Accordingly, the difference between those proceeds and the adjusted basis in the timber sold generally will be treated as gain from the sale of property used in a trade or business, which may be treated as capital gain under Section 1231 of the Code. Please read “-Sales of Coal Reserves and Timberland.” Gains from sale of timber by us that do not qualify under Section 631 of the Code generally will be taxable as ordinary income in the year of sale.

Timber Depletion

Timber is subject to cost depletion and is not subject to accelerated cost recovery, depreciation or percentage depletion. Timber depletion is determined with respect to each separate timber account (containing timber located in a timber "block") and is equal to the product obtained by multiplying the common units of timber cut by a fraction, the numerator of which is the aggregate adjusted basis of all timber included in such account and the denominator of which is the total number of timber common units in such timber account. The depletion allowance so calculated for the timber cut in a particular period represents the adjusted tax basis of such cut timber for purposes of determining gain or loss on its disposition. The tax basis of the remaining timber in each timber account is reduced by the depletion allowance for cut timber from such account.

Sales of Coal Reserves or Timberland

If any of our coal reserves or timberland are sold or otherwise disposed of in a taxable transaction, we will recognize (and allocate to our unitholders) any gain or loss measured by the difference between the amount realized (including the amount of any indebtedness assumed by the purchaser upon such disposition or to which such property is subject) and the adjusted tax basis of the property sold. Generally, the character of any gain or loss recognized upon that disposition will depend upon whether our coal reserves or the particular tract of timberland sold are held by it:

- for sale to customers in the ordinary course of business (i.e., we are a "dealer" with respect to that property);
- for use in a trade or business within the meaning of Section 1231 of the Code; or
- as a capital asset within the meaning of Section 1221 of the Code.

In determining dealer status with respect to coal reserves, timberland and other types of real estate, the courts have identified a number of factors for distinguishing between a particular property held for sale in the ordinary course of business and one held for investment. Any determination must be based on all the facts and circumstances surrounding the particular property and sale in question.

We intend to hold our coal reserves and timberland for the purposes of generating cash flow from coal royalties and periodic harvesting and sale of timber and achieving long-term capital appreciation. Although we may consider strategic sales of coal reserves and timberland consistent with achieving long-term capital appreciation, we do not anticipate frequent sales, nor significant marketing, improvement or subdivision activity in connection with any strategic sales. Thus, we do not believe that we will be viewed as a dealer. In light of the factual nature of this question, however, there is no assurance that our purposes for holding our properties will not change and that its future activities will not cause us to be a "dealer" in coal reserves or timberland.

If we are not a dealer with respect to our coal reserves or our timberland and we have held the disposed property for more than a one-year period primarily for use in our trade or business, the character of any gain or loss realized from a disposition of the property will be determined under Section 1231 of the Code. If we have not held the property for more than one year at the time of the sale, gain or loss from the sale will be taxable as ordinary income.

A unitholder's distributive share of any Section 1231 gain or loss generated by us will be aggregated with any other gains and losses realized by that unitholder from the disposition of property used in the trade or business, as defined in Section 1231(b) of the Code, and from the involuntary conversion of such properties and of capital assets held in connection with a trade or business or a transaction entered into for profit for the requisite holding period. If a net gain results, all such gains and losses will be long-term capital gains and losses; if a net loss results, all such gains and losses will be ordinary income and losses. Net Section 1231 gains will be treated as ordinary income to the extent of prior net Section 1231 losses of the taxpayer or predecessor taxpayer for the five most recent prior taxable years to the extent such losses have not previously been offset against Section 1231 gains. Losses are deemed recaptured in the chronological order in which they arose.

If we are not a dealer with respect to its coal reserves or a particular tract of timberland, and that property is not used in a trade or business, the property will be a "capital asset" within the meaning of Section 1221 of the Code. Gain or loss recognized from the disposition of that property will be taxable as capital gain or loss, and the character of such capital gain or loss as long-term or short-term will be based upon our holding period in such property at the time of its sale. The requisite holding period for long-term capital gain is more than one year.

Upon a disposition of coal reserves or timberland, a portion of the gain, if any, equal to the lesser of (i) the depletion deductions that reduced the tax basis of the disposed mineral property plus deductible development and mining exploration expenses, or (ii) the amount of gain recognized on the disposition, will be treated as ordinary income to us.

Valuation and Tax Basis of Each of Our Properties

The federal income tax consequences of the ownership and disposition of common units will depend in part on our estimates of the relative fair market values and the tax basis of each of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of tax basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or tax basis are later found to be incorrect, the character and amount of items of income, gain, loss or deduction previously reported by a unitholder could change, and such unitholder could be required to adjust its tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss

A unitholder will be required to recognize gain or loss on a sale or exchange of a unit equal to the difference, if any, between the unitholder's amount realized and the adjusted tax basis in the unit sold. A unitholder's amount realized generally will equal the sum of the cash and the fair market value of other property it receives plus its share of our nonrecourse liabilities with respect to the unit sold or exchanged. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale or exchange of a unit could result in a tax liability in excess of any cash received from such sale or exchange.

Except as noted below, gain or loss recognized by a unitholder on the sale or exchange of a unit held for more than one year generally will be taxable as long-term capital gain or loss. However, gain or loss recognized on the disposition of common units will be separately computed and taxed as ordinary income or loss under Section 751 of the Code to the extent attributable to Section 751 Assets, such as depreciation recapture and our "inventory items," regardless of whether such inventory item has substantially appreciated in value. Ordinary income attributable to Section 751 Assets may exceed net taxable gain realized on the sale or exchange of a unit and may be recognized even if there is a net taxable loss realized on the sale or exchange of a unit. Thus, a unitholder may recognize both ordinary income and capital gain or loss upon a sale or exchange of a unit. Net capital loss may offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year.

For purposes of calculating gain or loss on the sale or exchange of a unit, the unitholder's adjusted tax basis will be adjusted by its allocable share of our income or loss in respect of its unit for the year of the sale. Furthermore, as described above, the IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in its entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership.

Treasury Regulations under Section 1223 of the Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling discussed in the paragraph above, a unitholder will be unable to select high or low basis common units to sell or exchange as would be the case with corporate stock, but, according to the Treasury Regulations, such unitholder may designate specific common units sold for purposes of determining the holding period of the common units transferred. A unitholder electing to use the actual holding period of any unit transferred must consistently use that identification method for all subsequent sales or exchanges of our common units. A unitholder considering the purchase of additional common units or a sale or exchange of common units purchased in separate transactions is urged to consult its tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" financial position, including a partnership interest with respect to which gain would be recognized if it were sold, assigned or terminated at its fair market value, in the event the taxpayer or a related person enters into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is authorized to issue Treasury Regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position. Please read “-Tax Consequences of Unit Ownership-Treatment of Securities Loans.”

Allocations Between Transferors and Transferees

In general, our taxable income or loss will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of common units owned by each of them as of the opening of the applicable exchange on the first business day of the month (the “Allocation Date”). Nevertheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service, and gain or loss realized on a sale or other disposition of our assets or, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction will be allocated among the unitholders on the Allocation Date in the month in which such income, gain, loss or deduction is recognized. As a result, a unitholder transferring common units may be allocated income, gain, loss and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Code and most publicly traded partnerships use similar simplifying conventions, existing Treasury Regulations do not specifically authorize the use of the proration method we have adopted. Accordingly, Vinson & Elkins L.L.P. is unable to opine on the validity of this method of allocating income and deductions between transferee and transferor unitholders. If the IRS determines that this method is not allowed under the Treasury Regulations our taxable income or losses could be reallocated among our unitholders. Under our partnership agreement, we are authorized to revise our method of allocation between transferee and transferor unitholders, as well as among unitholders whose interests vary during a taxable year, to conform to a method permitted under the Treasury Regulations.

A unitholder who disposes of common units prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deduction attributable to the month of disposition (and any other month during the quarter to which such cash distribution relates and the holder held common units on the first day of such month) but will not be entitled to receive a cash distribution for that period.

Notification Requirements

A unitholder who sells or exchanges any of its common units is generally required to notify us in writing of that transaction within 30 days after the transaction (or, if earlier, January 15 of the year following the transaction in the case of a seller). Upon receiving such notifications, we are required to notify the IRS of the transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a transfer of common units may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker who will satisfy such requirements.

Uniformity of Common Units

Because we cannot match transferors and transferees of common units and for other reasons, we must maintain uniformity of the economic and tax characteristics of the common units to a purchaser of these common units. As a result of the need to preserve uniformity, we may be unable to completely comply with a number of federal income tax requirements. Any non-uniformity could have a negative impact on the value of our common units. Please read “-Tax Consequences of Unit Ownership-Section 754 Election.”

Our partnership agreement permits our general partner to take positions in filing our tax returns that preserve the uniformity of our common units. These positions may include reducing the depreciation, amortization or loss deductions to which a unitholder would otherwise be entitled or reporting a slower amortization of Section 743(b) adjustments for some unitholders than that to which they would otherwise be entitled. Vinson & Elkins L.L.P. is unable to opine as to the validity of such filing positions.

A unitholder’s adjusted tax basis in common units is reduced by its share of our deductions (whether or not such deductions were claimed on an individual income tax return) so that any position that we take that understates deductions will overstate the unitholder’s basis in its common units, and may cause the unitholder to understate gain or overstate loss on any sale of such common units. Please read “- Disposition of Common Units-Recognition of Gain or Loss” and “-Tax Consequences of Unit Ownership-Section 754 Election” above. The IRS may challenge one or more of any positions we take to preserve the uniformity of our common units. If such a challenge were sustained, the uniformity of common units might be affected, and, under some circumstances, the gain from the sale of our common units might be increased without the benefit of additional deductions.

In addition, as described above at “-Tax Consequences of Unit Ownership-Allocation of Income, Gain, Loss and Deduction,” if we aggregate multiple issuances of units for purposes of making adjustments to “book” basis and related tax allocations, we will treat each of our units as having the same capital account balance, regardless of the price actually paid by each purchaser of units in the aggregated offerings. Our counsel, Vinson & Elkins L.L.P., is unable to opine as to the validity of such an approach.

We do not expect the number of affected units, or the differences between the purchase price of a unit and the initial capital account balance assigned to the unit, to be material, and we do not expect this convention to have a material effect upon the trading of our units.

Tax-Exempt Organizations and Other Investors

Ownership of our common units by employee benefit plans and other tax-exempt organizations, as well as by non-resident alien individuals, non-U.S. corporations and other non-U.S. persons (collectively, “Non-U.S. Unitholders”) raises issues unique to those investors and, as described below, may have substantial adverse tax consequences to them. Each prospective unitholder that is a tax-exempt entity or a Non-U.S. Unitholder should consult its tax advisors before investing in our common units.

Employee benefit plans and most other tax-exempt organizations, including IRAs and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income will be unrelated business taxable income and will be taxable to a tax-exempt unitholder. Tax-exempt unitholders with more than one unrelated trade or business (including by attribution from the Partnership to the extent it is engaged in one or more unrelated trade or business) are required to separately compute their unrelated business taxable income with respect to each unrelated trade or business (including for purposes of determining any net operating loss deduction). As a result, it may not be possible for tax-exempt unitholders to utilize losses from an investment in the Partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa.

Non-U.S. Unitholders are taxed by the United States on income effectively connected with a U.S. trade or business (“effectively connected income”) and on certain types of U.S.-source non-effectively connected income (such as dividends), unless exempted or further limited by an income tax treaty. Each Non-U.S. Unitholder will be considered to be engaged in business in the United States because of its ownership of our common units. Furthermore, Non-U.S. Unitholders will be deemed to conduct such activities through a permanent establishment in the United States within the meaning of an applicable tax treaty. Consequently, each Non-U.S. Unitholder will be required to file federal tax returns to report its share of our income, gain, loss or deduction and pay federal income tax on its share of our net income or gain. Moreover, under rules applicable to publicly-traded partnerships, distributions to Non-U.S. Unitholders are subject to withholding at the highest applicable effective tax rate. Each Non-U.S. Unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or W-8BEN-E (or other applicable or successor form) in order to obtain credit for these withholding taxes.

In addition, if a Non-U.S. Unitholder is classified as a non-U.S. corporation, it will be treated as engaged in a United States trade or business and may be subject to the U.S. branch profits tax at a rate of 30%, in addition to regular U.S. federal income tax, on its share of our income and gain as adjusted for changes in the foreign corporation’s “U.S. net equity” to the extent reflected in the corporation’s earnings and profits. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a “qualified resident.” In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Code.

A Non-U.S. Unitholder who sells or otherwise disposes of a unit will be subject to U.S. federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the Non-U.S. Unitholder. Gain realized by a Non-U.S. Unitholder from the sale of its interest in a partnership that is engaged in a trade or business in the United States will be considered to be “effectively connected” with a U.S. trade or business to the extent that gain that would be recognized upon a sale by the partnership of all of its assets would be “effectively connected” with a U.S. trade or business. Thus, all of a Non-U.S. Unitholder’s gain from the sale or other disposition of our common units would be treated as effectively connected with a unitholder’s indirect U.S. trade or business constituted by its investment in us and would be subject to U.S. federal income tax. As a result of the effectively connected income rules described above, the exclusion from U.S. taxation under the Foreign Investment in Real Property Tax Act for gain from the sale of partnership common units regularly traded on an established securities market will not prevent a Non-U.S. Unitholder from being subject to U.S. federal income tax on gain from the sale or disposition of its common units to the extent such gain is effectively connected with a U.S. trade or business. We expect a significant portion of the gain from the sale or disposition of our common units to be treated as effectively connected with a U.S. trade or business.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferees but were not withheld. Because the “amount realized” includes a partner’s share of the partnership’s liabilities, 10% of the amount realized could exceed the total cash purchase price for the common units. For this and other reasons, the IRS has suspended the application of this withholding rule to open market transfers of interest in publicly traded partnerships, pending promulgation of regulations that address the amount to be withheld, the reporting necessary to determine such amount and the appropriate party to withhold such amounts, but it is not clear if or when such regulations will be issued.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each taxable year, specific tax information, including a Schedule K-1, which describes its share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure our unitholders that those positions will yield a result that conforms to all of the requirements of the Code, Treasury Regulations or administrative interpretations of the IRS.

The IRS may audit our federal income tax information returns. Neither we nor Vinson & Elkins L.L.P. can assure prospective unitholders that the IRS will not successfully challenge the positions we adopt, and such a challenge could adversely affect the value of our common units. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and may result in an audit of the unitholder's own return. Any audit of a unitholder's return could result in adjustments unrelated to our returns.

Publicly-traded partnerships are treated as entities separate from their owners for purposes of federal income tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings for each of the partners. Pursuant to the Bipartisan Budget Act of 2015, for taxable years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, unless we elect to have our general partner, unitholders and former unitholders take any audit adjustment into account in accordance with their interests in us during the taxable year under audit. Similarly, for such taxable years, if the IRS makes audit adjustments to income tax returns filed by an entity in which we are a member or partner, it may assess and collect any taxes (including penalties and interest) resulting from such audit adjustment directly from such entity.

Generally, we expect to elect to have our general partner, unitholders and former unitholders take any such audit adjustment into account in accordance with their interests in us during the taxable year under audit, but there can be no assurance that such election will be effective in all circumstances. If we are unable or if it is not economical to have our general partner, unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the taxable year under audit, our then current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our common units during the taxable year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties or interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable for taxable years beginning on or prior to December 31, 2017. Congress has proposed changes to the Bipartisan Budget Act, and we anticipate that amendments may be made. Accordingly, the manner in which these rules may apply to us in the future is uncertain.

Additionally, pursuant to the Bipartisan Budget Act of 2015, the Code will no longer require that we designate a Tax Matters Partner. Instead, for taxable years beginning after December 31, 2017, we will be required to designate a partner, or other person, with a substantial presence in the United States as the partnership representative ("Partnership Representative"). The Partnership Representative will have the sole authority to act on our behalf for purposes of, among other things, federal income tax audits and judicial review of administrative adjustments by the IRS. If we do not make such a designation, the IRS can select any person as the Partnership Representative. We currently anticipate that we will designate our general partner as the Partnership Representative. Further, any actions taken by us or by the Partnership Representative on our behalf with respect to, among other things, federal income tax audits and judicial review of administrative adjustments by the IRS, will be binding on us and all of our unitholders.

Additional Withholding Requirements

Withholding taxes may apply to certain types of payments made to "foreign financial institutions" (as specially defined in the Code) and certain other non-U.S. entities. Specifically, a 30% withholding tax may be imposed on interest, dividends and other fixed or determinable annual or periodic gains, profits and income from sources within the United States ("FDAP Income"), or gross proceeds from the sale or other disposition of any property of a type which can produce interest or dividends from sources within the United States ("Gross Proceeds") paid to a foreign financial institution or to a "non-financial foreign entity" (as specially defined in the Code), unless (i) the foreign financial institution undertakes certain diligence and reporting, (ii) the non-financial foreign entity either certifies it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. If the payee is a foreign financial institution and is subject to the diligence and reporting requirements in clause (i) above, it must enter into an agreement with the U.S. Department of the Treasury requiring, among other things, that it undertake to identify accounts held by certain U.S. persons or U.S.-owned foreign entities, annually report certain information about such accounts, and withhold 30% on payments to noncompliant foreign financial institutions and certain other account holders. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing these requirements may be subject to different rules.

Generally these rules apply to current payments of FDAP Income and will apply to payments of relevant Gross Proceeds made on or after January 1, 2019. Thus, to the extent we have FDAP Income or we have Gross Proceeds on or after January 1, 2019 that are not treated as effectively connected with a U.S. trade or business (please read "-Tax-Exempt Organizations and Other Investors"), a unitholder that is a foreign financial institution or certain other non-U.S. entity, or a person that holds its common units through such foreign entities, may be subject to withholding on distributions they receive from us, or its distributive share of our income, pursuant to the rules described above.

Each prospective unitholder should consult its own tax advisors regarding the potential application of these withholding provisions to its investment in our common units.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- a statement regarding whether the beneficial owner is:
  - a non-U.S. person;
  - a non-U.S. government, an international organization or any wholly-owned agency or instrumentality of either of the foregoing; or
  - a tax-exempt entity;
- the amount and description of common units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Each broker and financial institution is required to furnish additional information, including whether such broker or financial institution is a U.S. person and specific information on any common units such broker or financial institution acquires, holds or transfers for its own account. A penalty of per failure, with a significant maximum penalty per calendar year, is imposed by the Code for failure to report that information to us. The nominee is required to supply the beneficial owner of our common units with the information furnished to us.

Accuracy-Related Penalties

Certain penalties may be imposed as a result of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for the underpayment of that portion and that the taxpayer acted in good faith regarding the underpayment of that portion. We do not anticipate that any accuracy-related penalties will be assessed against us.

State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders may be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangibles taxes that may be imposed by the various jurisdictions in which we conduct business or own property now or in the future or in which the unitholder is a resident. We conduct business or own property in many states in the United States. Some of these states may impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose a personal income tax. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider the potential impact of such taxes on its investment in us.

A unitholder may be required to file income tax returns and pay income taxes in some or all of the jurisdictions in which we do business or own property, though such unitholder may not be required to file a return and pay taxes in certain jurisdictions because its income from such jurisdictions falls below the jurisdiction's filing and payment requirement. Further, a unitholder may be subject to penalties for a failure to comply with any filing or payment requirement applicable to such unitholder. Some of the jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return.

IT IS THE RESPONSIBILITY OF EACH UNITHOLDER TO INVESTIGATE THE LEGAL AND TAX CONSEQUENCES, UNDER THE LAWS OF PERTINENT JURISDICTIONS, OF HIS INVESTMENT IN US. WE STRONGLY RECOMMEND THAT EACH PROSPECTIVE UNITHOLDER CONSULT, AND DEPEND UPON, ITS OWN TAX COUNSEL OR OTHER ADVISOR WITH REGARD TO THOSE MATTERS. FURTHER, IT IS THE RESPONSIBILITY OF EACH UNITHOLDER TO FILE ALL STATE, LOCAL AND NON-U.S., AS WELL AS U.S. FEDERAL TAX RETURNS THAT MAY BE REQUIRED OF IT. VINSON & ELKINS L.L.P. HAS NOT RENDERED AN OPINION ON THE STATE, LOCAL, ALTERNATIVE MINIMUM TAX OR NON-U.S. TAX CONSEQUENCES OF AN INVESTMENT IN US.