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 1-32740

ENERGY TRANSFER EQUITY, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**30-0108820**
(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 1,079,145,561 Common Units outstanding.

FORM 10-Q

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

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Forward-Looking Statements

Certain matters discussed in this report, as well as certain statements by Energy Transfer Equity, L.P. (“Energy Transfer Equity” the “Partnership” or “ETE”) in periodic press releases and certain oral statements of Energy Transfer Equity management 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,” “project,” “expect,” “plan,” “goal,” “forecast,” “estimate,” “intend,” “continue,” “believe,” “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, estimated or expressed, forecasted, projected or expected 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 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)
BBtu	billion British thermal units
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy content
CDM	CDM Resource Management LLC
CDM E&T	CDM Environmental & Technical Services LLC
DOJ	U.S. Department of Justice
EPA	Environmental Protection Agency
ETP	Energy Transfer Partners, L.P.
ETP GP	Energy Transfer Partners GP, L.P., the general partner of ETP
ETP Holdco	ETP Holdco Corporation
ETP Series A Preferred Units	ETP’s 6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
ETP Series B Preferred Units	ETP’s 6.625% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
ETP Series C Preferred Units	ETP’s 7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Exchange Act	Securities Exchange Act of 1934
FERC	Federal Energy Regulatory Commission
GAAP	accounting principles generally accepted in the United States of America
IDRs	incentive distribution rights
Lake Charles LNG	Lake Charles LNG Company, LLC
LIBOR	London Interbank Offered Rate
MBbls	thousand barrels
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
PCBs	polychlorinated biphenyl
PES	Philadelphia Energy Solutions
Regency	Regency Energy Partners LP
Rover	Rover Pipeline LLC
SEC	Securities and Exchange Commission
Series A Convertible Preferred Units	ETE Series A convertible preferred units
Sunoco Logistics	Sunoco Logistics Partners L.P.
Sunoco LP	Sunoco LP (previously named Susser Petroleum Partners, LP)
Sunoco LP Series A Preferred Units	Sunoco LP Series A Preferred Units previously held by ETE
Transwestern	Transwestern Pipeline Company, LLC
Trunkline	Trunkline Gas Company, LLC
USAC	USA Compression Partners, LP

Adjusted EBITDA is a term used throughout this document. We define 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, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for non-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 EQUITY, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	March 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 547	$ 336
Accounts receivable, net	3,590	4,504
Accounts receivable from related companies	93	53
Inventories	1,861	2,022
Derivative assets	26	24
Income taxes receivable	166	136
Other current assets	304	295
Current assets held for sale	6	3,313
Total current assets	6,593	10,683
Property, plant and equipment	72,646	71,177
Accumulated depreciation and depletion	(10,671)	(10,089)
	61,975	61,088
Advances to and investments in unconsolidated affiliates	2,701	2,705
Other non-current assets, net	936	886
Intangible assets, net	5,936	6,116
Goodwill	4,768	4,768
Total assets	$ 82,909	$ 86,246

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

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

	March 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,704	$ 4,685
Accounts payable to related companies	53	31
Derivative liabilities	151	111
Accrued and other current liabilities	2,944	2,582
Current maturities of long-term debt	409	413
Current liabilities held for sale	—	75
Total current liabilities	7,261	7,897
Long-term debt, less current maturities	41,779	43,671
Non-current derivative liabilities	97	145
Deferred income taxes	3,026	3,315
Other non-current liabilities	1,244	1,217
Commitments and contingencies		
Redeemable noncontrolling interests	21	21
Equity:		
General Partner	(3)	(3)
Limited Partners:		
Common Unitholders	(1,696)	(1,643)
Series A Convertible Preferred Units	519	450
Total partners’ deficit	(1,180)	(1,196)
Noncontrolling interest	30,661	31,176
Total equity	29,481	29,980
Total liabilities and equity	$ 82,909	$ 86,246

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

ENERGY TRANSFER EQUITY, 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	1,546
Crude sales	3,254	2,542
Gathering, transportation and other fees	1,430	1,065
Refined product sales	3,810	3,015
Other	296	481
Total revenues	11,882	9,661
COSTS AND EXPENSES:		
Cost of products sold	9,245	7,510
Operating expenses	724	601
Depreciation and amortization	665	628
Selling, general and administrative	148	165
Total costs and expenses	10,782	8,904
OPERATING INCOME	1,100	757
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(466)	(473)
Equity in earnings of unconsolidated affiliates	79	87
Losses on extinguishments of debt	(106)	(25)
Gains on interest rate derivatives	52	5
Other, net	57	17
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX (BENEFIT) EXPENSE	716	368
Income tax (benefit) expense from continuing operations	(10)	38
INCOME FROM CONTINUING OPERATIONS	726	330
Loss from discontinued operations, net of income taxes	(237)	(11)
NET INCOME	489	319
Less: Net income attributable to noncontrolling interest	126	80
NET INCOME ATTRIBUTABLE TO PARTNERS	363	239
General Partner’s interest in net income	1	1
Convertible Unitholders' interest in income	21	6
Limited Partners’ interest in net income	$ 341	$ 232
INCOME FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT:		
Basic	$ 0.32	$ 0.22
Diluted	$ 0.32	$ 0.21
NET INCOME PER LIMITED PARTNER UNIT:		
Basic	$ 0.31	$ 0.22
Diluted	$ 0.31	$ 0.21

* As adjusted. See Note 1.

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

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

	Three Months Ended March 31,	
	2018	2017*
Net income	$ 489	$ 319
Other comprehensive income, net of tax:		
Change in value of available-for-sale securities	(2)	2
Actuarial gain relating to pension and other postretirement benefit plans	(2)	(2)
Change in other comprehensive income from unconsolidated affiliates	5	—
	1	—
Comprehensive income	490	319
Less: Comprehensive income attributable to noncontrolling interest	127	80
Comprehensive income attributable to partners	$ 363	$ 239

* As adjusted. See Note 1.

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

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

	General Partner	Common Unitholders	Series A Convertible Preferred Units	Noncontrolling Interest	Total
Balance, December 31, 2017	$ (3)	$ (1,643)	$ 450	$ 31,176	$ 29,980
Distributions to partners	(1)	(265)	—	—	(266)
Distributions to noncontrolling interest	—	—	—	(893)	(893)
Distributions reinvested	—	(58)	58	—	—
Subsidiary units repurchased	—	(98)	(6)	80	(24)
Subsidiary units issued	—	1	—	19	20
Capital contributions received from noncontrolling interests	—	—	—	229	229
Other comprehensive income, net of tax	—	—	—	1	1
Cumulative effect adjustment due to change in accounting principle (see Note 1)	—	—	—	(54)	(54)
Other, net	—	26	(4)	(23)	(1)
Net income	1	341	21	126	489
Balance, March 31, 2018	$ (3)	$ (1,696)	$ 519	$ 30,661	$ 29,481

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

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

	Three Months Ended March 31,	
	2018	2017*
OPERATING ACTIVITIES		
Net income	$ 489	$ 319
Reconciliation of net income to net cash provided by operating activities:		
Loss from discontinued operations	237	11
Depreciation, depletion and amortization	665	628
Deferred income taxes	(12)	37
Amortization included in interest expense	4	5
Non-cash compensation expense	23	27
Loss on extinguishment of debt	106	25
Equity in earnings of unconsolidated affiliates	(79)	(87)
Distributions from unconsolidated affiliates	61	46
Inventory valuation adjustments	(25)	13
Distributions on unvested awards	(16)	(9)
Other non-cash	(71)	(59)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation	757	(185)
Net cash provided by operating activities	2,139	771
INVESTING ACTIVITIES		
Cash proceeds from sale of Bakken Pipeline interest	—	2,000
Cash paid for acquisitions, net of cash received	(5)	(330)
Capital expenditures (excluding allowance for equity funds used during construction)	(1,737)	(1,408)
Contributions in aid of construction costs	20	6
Contributions to unconsolidated affiliates	(8)	(111)
Distributions from unconsolidated affiliates in excess of cumulative earnings	26	90
Other	3	(3)
Net cash (used in) provided by investing activities	(1,701)	244
FINANCING ACTIVITIES		
Proceeds from borrowings	6,627	9,000
Repayments of long-term debt	(8,541)	(9,809)
Cash paid on affiliate notes	—	(268)
Subsidiary units repurchased	(24)	—
Units issued for cash	—	568
Subsidiary units issued for cash	20	299
Distributions to partners	(266)	(251)
Debt issuance costs	(117)	(53)
Distributions to noncontrolling interests	(893)	(752)
Capital contributions from noncontrolling interest	229	106
Redemption of ETP Convertible Preferred Units	—	(53)
Other, net	(2)	4
Net cash used in financing activities	(2,967)	(1,209)

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

DISCONTINUED OPERATIONS				
Operating activities		(485)		121
Investing activities		3,214		(40)
Changes in cash included in current assets held for sale		11		(1)
Net increase in cash and cash equivalents of discontinued operations		2,740		80
Increase (decrease) in cash and cash equivalents		211		(114)
Cash and cash equivalents, beginning of period		336		467
Cash and cash equivalents, end of period	$	547	$	353

* As adjusted. See Note 1.

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

ENERGY TRANSFER EQUITY, 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

Unless the context requires otherwise, references to “we,” “us,” “our,” the “Partnership” and “ETE” mean Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to the “Parent Company” mean Energy Transfer Equity, L.P. on a stand-alone basis.

The consolidated financial statements of ETE presented herein include the results of operations of:

- the Parent Company;
- our controlled subsidiaries, ETP and Sunoco LP;
- consolidated subsidiaries of our controlled subsidiaries and our wholly-owned subsidiaries that own general partner interests and IDRs in ETP and Sunoco LP; and
- our wholly-owned subsidiary, Lake Charles LNG.

Our subsidiaries also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

On March 31, 2018, subsequent to Sunoco LP’s repurchase of the 12 million Sunoco LP Series A Preferred Units held by ETE, our interests in ETP and Sunoco LP consisted of 100% of the respective general partner interests and IDRs, as well as approximately 27.5 million ETP common units, and approximately 2.3 million Sunoco LP common units. Additionally, ETE owns 100 ETP Class I Units, which are currently not entitled to any distributions.

Business Operations

The Parent Company’s principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Sunoco LP and cash flows from the operations of Lake Charles LNG. The Parent Company’s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. Parent Company-only assets are not available to satisfy the debts and other obligations of ETE’s subsidiaries. In order to understand the financial condition of the Parent Company on a stand-alone basis, see Note 15 for stand-alone financial information apart from that of the consolidated partnership information included herein.

Our financial statements reflect the following reportable business segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Sunoco LP, including the consolidated operations of Sunoco LP;
- Investment in Lake Charles LNG, including the operations of Lake Charles LNG; and
- Corporate and Other, including the following:
    - activities of the Parent Company; and
    - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

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 included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017, filed with the SEC on February 23, 2018. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

For prior periods reported herein, certain transactions related to the business of legacy Sunoco Logistics have been reclassified from cost of products sold to operating expenses; these transactions include sales between operating subsidiaries and their marketing affiliate. Certain other prior period amounts were reclassified to conform to the 2018 presentation. Additionally, there are reclassifications of certain balances to assets and liabilities held for sale and certain revenues and expenses to discontinued operations. These reclassifications had no impact on net income or total equity.

Change in Accounting Policy

Inventory Accounting Change

During the fourth quarter of 2017, we elected to change our 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 product and NGL associated with the legacy Sunoco Logistics business. Our 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	$ 7,539	$ (29)	$ 7,510
Operating income	728	29	757
Income before income tax expense	339	29	368
Net income	290	29	319
Net income attributable to noncontrolling interest	51	29	80
Comprehensive income	290	29	319
Consolidated Statements of Cash Flows:			
Net income	290	29	319
Inventory Valuation Adjustments	11	2	13
Net change in operating assets and liabilities (change in inventories)	(154)	(31)	(185)

* Amounts reflect certain reclassifications made to conform to the current year presentation and include the impact of discontinued operations as discussed in Note 2.

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 certain of ETP's operations, as well as contracts deemed to be in-substance supply agreements in ETP's midstream operations. 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.

The Partnership has elected to apply the modified retrospective method to adopt 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.

For contracts in scope of the new revenue standard as of January 1, 2018, the Partnership recognized a cumulative effect adjustment to retained earnings to account for the differences in timing of revenue recognition. 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 adjustments to the opening balance sheet primarily relate to a change in timing of revenue recognition for variable consideration at Sunoco LP, such as incentives paid to customers, as well as a change in timing of revenue recognition for franchise fee revenue. Historically, an asset was recognized related to the contract incentives which was amortized over the life of the agreement. Under the new standard, the timing of the recognition of incentives changed due to application of the expected value method to estimate variable consideration. Additionally, under the new standard the change in timing of franchise fee revenue is due to the treatment of revenue recognition from the symbolic license over the term of the agreement.

The cumulative effect of the changes made to the Partnership's consolidated balance sheet for the adoption of ASU 2014-09 was as follows:

	Balance at December 31, 2017	Adjustments due to ASC 606	Balance at January 1, 2018
Assets:			
Other current assets	$ 295	$ 8	$ 303
Property and Equipment, net	61,088	—	61,088
Intangible assets, net	6,116	(100)	6,016
Other non-current assets, net	886	39	925
Liabilities and Equity:			
Other non-current liabilities	1,217	1	1,218
Noncontrolling interest	31,176	(54)	31,122

The adoption of the new revenue standard resulted in reclassifications between revenue, cost of sales, and operating expenses. Additionally, changes in timing of revenue recognition have required the creation of contract asset or contract liability balances, as well as certain balance sheet reclassifications. In accordance with the requirements of ASC Topic 606, the disclosure below shows the impact of adopting the new standard on the consolidated statement of operations and the consolidated balance sheet.

	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	1,430	1,617	(187)
Refined product sales	3,810	3,820	(10)
Other	296	296	—
Costs and expenses:			
Cost of products sold	9,245	9,433	(188)
Operating expenses	724	715	9
Depreciation and amortization	665	671	(6)
Assets:			
Other current assets	304	295	9
Property and Equipment, net	61,975	61,975	—
Intangible assets, net	5,936	6,041	(105)
Other non-current assets, net	936	894	42
Liabilities and Equity:			
Other non-current liabilities	1,244	1,243	1
Noncontrolling interest	30,661	30,716	(55)

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

USAC Transaction

On April 2, 2018, 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 representing limited partner interests in USAC ("USAC Common Units") for cash consideration equal to $250 million. Concurrently, 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 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, ETE's consolidated financial statements will reflect USAC as a consolidated subsidiary. At the time our consolidated financial statements were issued, the initial accounting for this business combination was incomplete; therefore, certain required disclosures have not been included herein.

The assets and liabilities of CDM and CDM E&T have not been reflected as held for sale, nor have CDM's or CDM E&T's results been reflected as discontinued operations in these financial statements.

Sunoco LP Acquisitions

On April 3, 2018, a subsidiary of Sunoco LP entered into an asset purchase agreement with Superior Plus Energy Services, Inc. ("Superior"), a New York Corporation, pursuant to which it agreed to acquire certain wholesale fuel distribution assets and related terminal assets from Superior for approximately $40 million plus working capital adjustments. The assets consist of a network of approximately 100 dealers, several hundred commercial contracts and three terminals, which are connected to major pipelines serving the Upstate New York market. The transaction closed on April 25, 2018.

On January 4, 2018, Sunoco LP entered into an asset purchase agreement with 7-Eleven and SEI Fuel, pursuant to which the Partnership agreed to acquire 26 retail fuel outlets from 7-Eleven and SEI Fuel for approximately $50 million. The transaction closed on April 2, 2018.

Sunoco LP Convenience Store and Real Estate Sales

On January 23, 2018, Sunoco LP completed the disposition of assets pursuant to the Amended and Restated Asset Purchase Agreement. As a result of the purchase agreement and subsequent closing, previously eliminated wholesale motor fuel sales to Sunoco LP's retail locations are reported as wholesale motor fuel sales to third parties. Also, the related accounts receivable from such sales are no longer eliminated from the Partnership's consolidated balance sheets and are reported as accounts receivable.

In connection with the closing of the transactions contemplated by the purchase agreement, Sunoco LP entered into a Distributor Motor Fuel Agreement dated as of January 23, 2018 (“Supply Agreement”), with 7-Eleven and SEI Fuel (collectively, “Distributor”). The Supply Agreement consists of a 15-year take-or-pay fuel supply arrangement under which Sunoco LP has agreed to supply approximately 2.0 billion gallons of fuel annually plus additional aggregate growth volumes of up to 500 million gallons to be added incrementally over the first four years. For the period from January 1, 2018 through January 22, 2018 and the three months ended March 31, 2017, Sunoco LP recorded sales to the sites that were subsequently sold to 7-Eleven of $199 million and $705 million, respectively, which were eliminated in consolidation. Sunoco LP recorded a cash inflow of $612 million from 7-Eleven in first quarter of 2018 since the sale related to payments on trade receivables.

On January 18, 2017, with the assistance of a third-party brokerage firm, Sunoco LP launched a portfolio optimization plan to market and sell 97 real estate assets. Real estate assets included in this process are company-owned locations, undeveloped greenfield sites and other excess real estate. Properties are located in Florida, Louisiana, Massachusetts, Michigan, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas and Virginia. The properties are being sold through a sealed-bid. Of the 97 properties, 47 have been sold, one is under contract to be sold, and eight continue to be marketed by the third-party brokerage firm. Additionally, 32 were sold to 7-Eleven and nine are part of the approximately 207 retail sites located in certain West Texas, Oklahoma, and New Mexico markets which will be operated by a commission agent.

The Partnership has concluded that it meets the accounting requirements for reporting the financial position, results of operations and cash flows of Sunoco LP’s retail divestment as discontinued operations.

The following tables present the aggregate carrying amounts of assets and liabilities classified as held for sale in the consolidated balance sheet:

	March 31, 2018	December 31, 2017
Carrying amount of assets classified as held for sale:		
Cash and cash equivalents	$ —	$ 21
Inventories	—	149
Other current assets	—	16
Property, plant and equipment, net	6	1,851
Goodwill	—	796
Intangible assets, net	—	477
Other non-current assets, net	—	3
Total assets classified as held for sale in the Consolidated Balance Sheet	$ 6	$ 3,313

	March 31, 2018	December 31, 2017
Carrying amount of liabilities classified as held for sale:		
Other current and non-current liabilities	$ —	$ 75
Total liabilities classified as held for sale in the Consolidated Balance Sheet	$ —	$ 75

The results of operations associated with discontinued operations are presented in the following table:

	Three Months Ended March 31,	
	2018	2017
REVENUES	$ 349	$ 1,586
COSTS AND EXPENSES		
Cost of products sold	305	1,339
Operating expenses	61	185
Depreciation, depletion and amortization	—	33
Selling, general and administrative	2	32
Total costs and expenses	368	1,589
OPERATING LOSS	(19)	(3)
Interest expense, net	2	6
Loss on extinguishment of debt and other	20	—
Other, net	23	5
LOSS FROM DISCONTINUED OPERATIONS BEFORE INCOME TAX BENEFIT	(64)	(14)
Income tax expense (benefit)	173	(3)
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	(237)	(11)
LOSS FROM DISCONTINUED OPERATIONS BEFORE INCOME TAX BENEFIT ATTRIBUTABLE TO ETE	$ (9)	$ —

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.

Non-cash investing and financing activities were as follows:

	Three Months Ended March 31,	
	2018	2017
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 1,011	$ 833
Losses from subsidiary common unit transactions	(103)	(52)
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	$ 812	$ 1,120
Crude oil	701	551
Spare parts and other	348	351
Total inventories	$ 1,861	$ 2,022

ETP utilizes commodity derivatives to manage price volatility associated with its natural gas inventories. 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 were $42.52 billion and $42.19 billion, respectively. As of December 31, 2017, the aggregate fair value and carrying amount of our consolidated debt obligations were $45.62 billion and $44.08 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the respective debt obligations' 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 — Calls	1	1	—
Options — Puts	1	1	—
Natural Gas Liquids — Forwards/Swaps	115	115	—
Refined Products — Futures	3	3	—
Total commodity derivatives	255	169	86
Other non-current assets	21	14	7
Total assets	$ 276	$ 183	$ 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	(2)	(2)	—
Forward Physical Contracts	(6)	—	(6)
Power:			
Forwards	(72)	—	(72)
Natural Gas Liquids — Swaps	(169)	(169)	—
Refined Products — Futures	(6)	(6)	—
Total commodity derivatives	(350)	(271)	(79)
Total liabilities	$ (517)	$ (271)	$ (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	—
Refined Products — Futures	1	1	—
Crude — Futures	2	2	—
Total commodity derivatives	321	277	44
Other non-current assets	21	14	7
Total assets	$ 342	$ 291	$ 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 — Swaps	(192)	(192)	—
Refined Products — Futures	(28)	(28)	—
Crude — Futures	(1)	(1)	—
Total commodity derivatives	(341)	(303)	(38)
Total liabilities	$ (560)	$ (303)	$ (257)

6. NET INCOME PER LIMITED PARTNER UNIT

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

	Three Months Ended March 31,	
	2018	2017
Income from continuing operations	$ 726	$ 330
Less: Income from continuing operations attributable to noncontrolling interest	354	91
Income from continuing operations, net of noncontrolling interest	372	239
Less: General Partner's interest in income	1	1
Less: Convertible Unitholders' interest in income	21	6
Income from continuing operations available to Limited Partners	$ 350	$ 232
Basic Income from Continuing Operations per Limited Partner Unit:		
Weighted average limited partner units	1,079.1	1,075.2
Basic income from continuing operations per Limited Partner unit	$ 0.32	$ 0.22
Basic income from discontinued operations per Limited Partner unit	$ (0.01)	$ 0.00
Diluted Income from Continuing Operations per Limited Partner Unit:		
Income from continuing operations available to Limited Partners	$ 350	$ 232
Dilutive effect of equity-based compensation of subsidiaries and distributions to Convertible Unitholders	21	6
Diluted income from continuing operations available to Limited Partners	$ 371	$ 238
Weighted average limited partner units	1,079.1	1,075.2
Dilutive effect of unconverted unit awards and Convertible Units	75.6	63.8
Diluted weighted average limited partner units	1,154.7	1,139.0
Diluted income from continuing operations per Limited Partner unit	$ 0.32	$ 0.21
Diluted income from discontinued operations per Limited Partner unit	$ (0.01)	$ 0.00

7. DEBT OBLIGATIONS

Parent Company Indebtedness

The Parent Company's indebtedness, including its senior notes, senior secured term loan and senior secured revolving credit facility, is secured by all of its and certain of its subsidiaries' tangible and intangible assets.

ETE Revolving Credit Facility

Pursuant to ETE's revolving credit agreement, which matures on March 24, 2022, the lenders have committed to provide advances up to an aggregate principal amount of $1.5 billion at any one time outstanding, and the Parent Company has the option to request increases in the aggregate commitments by up to $500 million in additional commitments.

As of March 31, 2018, borrowings of $873 million were outstanding under the Parent Company revolving credit facility and the amount available for future borrowings was $627 million.

Subsidiary Indebtedness

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 $1.0 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%.

Sunoco LP Senior Notes and Term Loan

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028. Sunoco LP used the proceeds from the private offering, along with proceeds from the closing of the asset purchase agreement with 7-Eleven to:

i. redeem in full its existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020, and $800 million in aggregate principal amount of 6.375% senior notes due 2023;

ii. repay in full and terminate its term loan;

iii. pay all closing costs in connection with the 7-Eleven transaction;

iv. redeem the outstanding Sunoco LP Series A Preferred Units; and

v. repurchase 17,286,859 Sunoco LP common units owned by ETP.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.50 billion revolving credit agreement, which matures in September 2019. As of March 31, 2018, the Sunoco LP credit facility had no outstanding borrowings and $8 million in standby letters of credit. The unused availability on the revolver at March 31, 2018 was $1.5 billion.

Compliance with Our Covenants

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

8. EQUITY

There were no changes in ETE common units and Series A Convertible Preferred Units during the three months ended March 31, 2018.

ETE Equity Distribution Agreement

In March 2017, the Partnership entered into an equity distribution agreement relating to at-the-market offerings of its common units with an aggregate offering price up to $1 billion. As of March 31, 2018, there have been no sales of common units under the equity distribution agreement.

ETE Series A Convertible Preferred Units

As of March 31, 2018, the Partnership had 329.3 million Series A Convertible Preferred Units outstanding with a carrying value of $519 million.

Repurchase Program

During the three months ended March 31, 2018, ETE did not repurchase any ETE common units under its current buyback program. As of March 31, 2018, $936 million remained available to repurchase under the current program.

Subsidiary Equity Transactions

The Parent Company accounts for the difference between the carrying amount of its investment in ETP and Sunoco LP and the underlying book value arising from the issuance or redemption of units by ETP and Sunoco LP (excluding transactions with the Parent Company) as capital transactions. As a result of these transactions, during the three months ended March 31, 2018, we recognized an decrease in partners' capital of $103 million.

ETP Equity Distribution Program

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

ETP Distribution Reinvestment Program

In July 2017, ETP initiated a new distribution reinvestment plan. During the three months ended March 31, 2018, distributions of $20 million were reinvested under the distribution reinvestment plan.

ETP Preferred Units

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

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

Distributions on the ETP 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 ETP 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 ETP Series C Preferred Units are redeemable at ETP's option on or after May 15, 2023 at a redemption price of $25 per ETP Series C Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Sunoco LP Common Unit Transactions

On February 7, 2018, subsequent to 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.

Sunoco LP Series A Preferred Units

In January 2018, Sunoco LP redeemed all outstanding Sunoco LP Series A Preferred Units held by ETE for an aggregate redemption amount of approximately $313 million. The redemption amount included the original consideration of $300 million and a 1% call premium plus accrued and unpaid quarterly distributions.

Parent Company Quarterly Distributions of Available Cash

Distributions declared and/or paid subsequent to December 31, 2017 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017 (1)	February 8, 2018	February 20, 2018	$ 0.3050
March 31, 2018 (1)	May 7, 2018	May 21, 2018	0.3050

(1) Certain common unitholders elected to participate in a plan pursuant to which those unitholders elected to forgo their cash distributions on all or a portion of their common units, and in lieu of receiving cash distributions on these common units for each such quarter, such unitholder received Series A Convertible Preferred Units, and (on a one-for-one basis for each common unit as to which the participating unitholder elected be subject to this plan) that entitled them to receive a cash distribution of up to $0.11 per Series A Convertible Preferred Unit. The quarter ended March 31, 2018 is the final quarter of participation in the plan.

Distributions declared and/or paid with respect to our Series A Convertible Preferred Units subsequent to December 31, 2017 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017	February 8, 2018	February 20, 2018	$ 0.1100
March 31, 2018	May 7, 2018	May 21, 2018	0.1100

ETP Quarterly Distributions of Available Cash

Under ETP's limited partnership agreement, within 45 days after the end of each quarter, ETP 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 ETP's partnership agreement. The general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct ETP's business. ETP 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 declared and/or paid by ETP 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 has agreed to relinquish its right to the following amounts of incentive distributions from ETP in future periods:

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

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

			Distribution per ETP 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

Sunoco LP Quarterly Distributions of Available Cash

The following are distributions declared and/or paid by Sunoco LP subsequent to December 31, 2017:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017	February 6, 2018	February 14, 2018	$ 0.8255
March 31, 2018	May 7, 2018	May 15, 2018	0.8255

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
Subtotal	2	3
Amounts attributable to noncontrolling interest	(2)	(3)
Total AOCI, net of tax	$ —	$ —

(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 ETP's accumulated other comprehensive income related to available-for-sale securities to ETP's common unitholders. The amount is reflected as noncontrolling interest in the Partnership's consolidated financial statements.

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 $38 million deferred benefit adjustment as the result of a state statutory rate reduction.

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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.

ETP's joint venture agreements require that they fund their proportionate share of capital contributions to their unconsolidated affiliates. Such contributions will depend upon their 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 with typical initial terms of 5 to 15 years, with some having a term of 40 years or more. 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 [(1)]	$ 40	$ 40
Less: Sublease rental income	(6)	(6)
Rental expense, net	$ 34	$ 34

(1) Includes contingent rentals totaling $1 million and $4 million for three months ended March 31, 2018 and 2017, respectively.

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.

Litigation Filed By or Against Williams

On April 6, 2016, The Williams Companies, Inc. ("Williams") filed a complaint against ETE and LE GP, LLC ("LE GP") in the Delaware Court of Chancery (the "First Delaware Williams Litigation"). Williams sought, among other things, to (a) rescind the issuance of the Partnership's Series A Convertible Preferred Units (the "Issuance") and (b) invalidate an amendment to ETE's partnership agreement that was adopted on March 8, 2016 as part of the Issuance.

On May 3, 2016, ETE and LE GP filed an answer and counterclaim in the First Delaware Williams Litigation. The counterclaim asserts in general that Williams materially breached its obligations under the ETE-Williams merger agreement (the "Merger Agreement") by (a) blocking ETE's attempts to complete a public offering of the Series A Convertible Preferred Units, including, among other things, by declining to allow Williams' independent registered public accounting firm to provide the auditor consent required to be included in the registration statement for a public offering and (b) bringing a lawsuit concerning the Issuance against Mr. Warren in the District Court of Dallas County, Texas, which the Texas state court later dismissed based on the Merger Agreement's forum-selection clause.

On May 13, 2016, Williams filed a second lawsuit in the Delaware Court of Chancery (the "Court") against ETE and LE GP and added Energy Transfer Corp LP, ETE Corp GP, LLC, and Energy Transfer Equity GP, LLC as additional defendants (collectively, "Defendants") (the "Second Delaware Williams Litigation"). In general, Williams alleged that Defendants breached the Merger Agreement by (a) failing to use commercially reasonable efforts to obtain from Latham & Watkins LLP ("Latham") the delivery of a tax opinion concerning Section 721 of the Internal Revenue Code ("721 Opinion"), (b) breaching a representation and warranty in the Merger Agreement concerning Section 721 of the Internal Revenue Code, and (c) taking actions that allegedly delayed the SEC in declaring the Form S-4 filed in connection with the merger (the "Form S-4") effective. Williams asked the Court, in general, to (a) issue a declaratory judgment that ETE breached the Merger Agreement, (b) enjoin ETE from terminating the Merger Agreement on the basis that it failed to obtain a 721 Opinion, (c) enjoin ETE from terminating the Merger Agreement on the basis that the transaction failed to close by the outside date, and (d) force ETE to close the merger or take various other affirmative actions.

ETE filed an answer and counterclaim in the Second Delaware Williams Litigation. In addition to the counterclaims previously asserted, ETE asserted that Williams materially breached the Merger Agreement by, among other things, (a) modifying or qualifying the Williams board of directors' recommendation to its stockholders regarding the merger, (b) failing to provide material information to ETE for inclusion in the Form S-4 related to the merger, (c) failing to facilitate the financing of the merger, (d) failing to use its reasonable best efforts to consummate the merger, and (e) breaching the Merger Agreement's forum-selection clause. ETE sought, among other things, a declaration that it could validly terminate the Merger Agreement after June 28, 2016 in the event that Latham was unable to deliver the 721 Opinion on or prior to June 28, 2016.

After a two-day trial on June 20 and 21, 2016, the Court ruled in favor of ETE on Williams' claims in the Second Delaware Williams Litigation and issued a declaratory judgment that ETE could terminate the merger after June 28, 2016 because of Latham's inability to provide the required 721 Opinion. The Court also denied Williams' requests for injunctive relief. The Court did not reach a decision regarding Williams' claims related to the Issuance or ETE's counterclaims. Williams filed a notice of appeal to the Supreme Court of Delaware on June 27, 2016. Williams filed an amended complaint on September 16, 2016 and sought a $410 million termination fee, and Defendants filed amended counterclaims and affirmative defenses. In response, Williams filed a motion to dismiss Defendants' amended counterclaims and to strike certain of Defendants' affirmative defenses.

On March 23, 2017, the Delaware Supreme Court affirmed the Court's ruling on the June trial, and as a result, Williams has conceded that its $10 billion damages claim is foreclosed, although its $410 million termination fee claim remains pending.

On December 1, 2017, the Court issued a Memorandum Opinion granting Williams' motion to dismiss in part and denying Williams' motion to dismiss in part. Trial is set for May 20, 2019.

Defendants cannot predict the outcome of the First Delaware Williams Litigation, the Second Delaware Williams 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 these lawsuits. Defendants believe that Williams' claims are without merit and intend to defend vigorously against them.

Unitholder Litigation Relating to the Issuance

On April 12, 2016, two purported ETE unitholders (the "Issuance Plaintiffs") filed putative class action lawsuits against ETE, LE GP, Kelcy Warren, John McReynolds, Marshall McCrea, Matthew Ramsey, Ted Collins, K. Rick Turner, William Williams, Ray Davis, and Richard Brannon (collectively, the "Issuance Defendants") in the Delaware Court of Chancery (the "Issuance Litigation"). Another purported ETE unitholder, Chester County Employees' Retirement Fund, later joined the Issuance Litigation.

The Issuance Plaintiffs allege that the Issuance breached various provisions of ETE's partnership agreement. The Issuance Plaintiffs seek, among other things, preliminary and permanent injunctive relief that (a) prevents ETE from making distributions to holders of the Series A Convertible Preferred Units and (b) invalidates an amendment to ETE's partnership agreement that was adopted on March 8, 2016 as part of the Issuance.

On August 29, 2016, the Issuance Plaintiffs filed a consolidated amended complaint, and in addition to the injunctive relief described above, seek class-wide damages allegedly resulting from the Issuance.

The matter was tried in front of Vice Chancellor Glasscock on February 19-21, 2018. Post-trial arguments were heard on April 16, 2018.

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

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	$ 54	$ 35
Non-current	326	337
Total environmental liabilities	$ 380	$ 372

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 $6 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

We operate our business in four operating segments, which are the same as our reportable segments, as follows:

- Investment in ETP;
- Investment in Sunoco LP;
- Investment in Lake Charles LNG; and
- Corporate and 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.

ETP’s intrastate transportation and storage revenue

ETP’s intrastate transportation and storage revenues are determined primarily by the volume of capacity ETP’s 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 ETP’s 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 ETP’s pipelines or inject/withdraw into or out of ETP’s 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 ETP accepts the customer’s request. Revenue is recognized for interruptible contracts at the time the services are performed.

ETP’s interstate transportation and storage revenue

ETP’s interstate transportation and storage revenues are determined primarily by the amount of capacity ETP’s 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 ETP’s storage facilities. ETP’s interstate transportation and storage 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, ETP 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 ETP’s pipelines or inject into or withdrawn out of ETP’s storage facilities. Consequently, ETP is 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 ETP accepts the customer’s request. Revenue is recognized for interruptible contracts at the time the services are performed.

ETP’s midstream revenue

ETP’s midstream revenues are derived primarily from margins ETP earns for natural gas volumes that are gathered, processed, and/or transported for ETP’s customers. The various types of revenue contracts ETP’s midstream operations enter into include:

Fixed fee gathering and processing: Contracts under which ETP provides 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 ETP gathers raw natural gas from a third party producer, processes the gas to convert it to pipeline quality natural gas, and redeliver to the producer a thermal-equivalent amount of pipeline quality natural gas. In exchange for these services, ETP retains 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 ETP provides 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:* ETP retains its POP percentage (non-cash consideration) and also any additional cash fees in exchange for providing the services. ETP recognizes revenue for the non-cash consideration and cash fees at the time the services are performed.

- *Mixed POP:* ETP purchases NGLs from the producer and retains a portion of the residue gas as non-cash consideration for services provided. ETP 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 NGL's ETP purchased and customer agreements (for the services provided related to the product that was returned to the customer). Given that these are hybrid agreements, ETP 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 ETP's midstream 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 statement of operations; therefore, identification of separate performance obligations would not impact the timing or geography of revenue recognition.

Certain contracts of ETP's midstream operations 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, ETP defers 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.

ETP's NGL and refined products transportation and services revenue

ETP's NGL and refined products 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 ETP accepts 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 ETP's NGL's and other related hydrocarbons at market rates. These contracts were not affected by ASC 606.

ETP's crude oil transportation and services revenue

ETP's crude oil operations 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 ETP's 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.

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 ETP accepts 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 ETP’s crude oil at market rates. These contracts were not affected by ASC 606.

ETP’s all other revenue

ETP’s other operations primarily include ETP’s 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. ETP also earns 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 related to these operations are recorded under the new standard.

Sunoco LP’s wholesale revenue

Sunoco LP’s wholesale operations earn revenue from the following channels: sales to Dealers, sales to Distributors, Unbranded Wholesale Revenue, Commission Agent Revenue, Rental Income, and Other Income. Wholesale motor fuel revenue consists primarily of the sale of motor fuel under supply agreements with third party customers and affiliates. Fuel supply contracts with Sunoco LP’s wholesale customers generally provide that Sunoco LP distribute motor fuel at a formula price based on published rates, volume-based profit margin, and other terms specific to the agreement. The customer is invoiced the agreed-upon price with most payment terms ranging less than 30 days. If the consideration promised in a contract includes a variable amount, Sunoco LP estimates the variable consideration amount and factors in such an estimate to determine the transaction price under the expected value method.

Revenue is recognized under the wholesale motor fuel contracts at the point in time the customer takes control of the fuel. At the time control is transferred to the customer the sale is considered final, because the agreements do not grant customers the right to return motor fuel. Under the new standard, to determine when control transfers to the customer, the shipping terms of the contract are assessed as shipping terms are considered a primary indicator of the transfer of control. For FOB shipping point terms, revenue is recognized at the time of shipment. The performance obligation with respect to the sale of goods is satisfied at the time of shipment since the customer gains control at this time under the terms. Shipping and/or handling costs that occur before the customer obtains control of the goods are deemed to be fulfillment activities and are accounted for as fulfillment costs. Once the goods are shipped, Sunoco LP is precluded from redirecting the shipment to another customer and revenue is recognized.

Commission agent revenue consists of sales from consignment agreements between Sunoco LP and select operators. Sunoco LP supplies motor fuel to sites operated by commission agents and sells the fuel directly to the end customer. In consignment arrangements, control of the product is transferred at the point in time when the goods are removed from consignment stock and sold to the end customer. To reflect the transfer of control, Sunoco LP recognizes consignment revenue at the point in time fuel is sold to the end customer.

Sunoco LP’s retail revenue

Sunoco LP’s retail operations earn revenue from the following channels: Retail Motor Fuel Sales, Merchandise Sales, and Other Income. Retail Motor Fuel Sales consist of fuel sales to consumers at company-operated retail convenience stores. Merchandise Revenue comprises the in-store merchandise and foodservice sales at company-operated convenience stores. Other Income represents a variety of other services within Sunoco LP’s retail operations including car washes, lottery, automated teller machines, money orders, prepaid phone cards and wireless services. Revenue from retail operations is recognized when (or as) the performance obligations are satisfied (i.e. when the customer obtains control of the good).

Lake Charles LNG revenue

Our Lake Charles segment revenues are primarily derived from terminalling services for shippers by receiving LNG at the facility for storage and delivering such LNG to shippers, either in liquid state or gaseous state after regasification. Lake Charles LNG derives all of its revenue from a series of long term contracts with a wholly-owned subsidiary of BG Group plc (“BG”). Terminalling revenue is generated from fees paid by BG for storage and other associated services at the terminal. Payment for services under these contracts are typically due the month after the services have been performed.

The terminalling agreements are considered to be firm agreements, because they include fixed fee components that are charged regardless of the volumes transported by BG or services provided at the terminal.

The performance obligation with respect to firm contracts is a promise to provide a single type of service (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.

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.

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. Additionally, Sunoco LP maintains some franchise agreements requiring dealers to make one-time upfront payments for long term license agreements. The Partnership recognizes a contract liability when the upfront payment is received and recognizes revenue over the term of the license. As of March 31, 2018, the Partnership had $317 million in deferred revenues representing the current value of our future performance obligations.

The balances of receivables from contracts with customers listed in the table below include both current trade receivables and long-term receivables, net of allowance for doubtful accounts. The allowance for receivables represents Sunoco LP’s best estimate of the probable losses associated with potential customer defaults. Sunoco LP determines the allowance based on historical experience and on a specific identification basis.

The opening and closing balances of Sunoco LP’s contract assets and contract liabilities are as follows:

	Balance at January 1, 2018	Balance at March 31, 2018	Increase/ (Decrease)
Contract Balances			
Contract Asset	$ 51	$ 55	$ 4
Accounts receivable from contracts with customers	445	393	(52)
Contract Liability	1	1	—

The amount of revenue recognized in the current period that was included in the deferred revenue liability balance 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.

Sunoco LP distributes fuel under long-term contracts to branded distributors, branded and unbranded third party dealers, and branded and unbranded retail fuel outlets. Sunoco LP branded supply contracts with distributors generally have both time and volume commitments that establish contract duration. These contracts have an initial term of approximately nine years, with an estimated, volume-weighted term remaining of approximately four years.

As part of the asset purchase agreement with 7-Eleven, Sunoco LP and 7-Eleven and SEI Fuel (collectively, the “Distributor”) have entered into a 15-year take-or-pay fuel supply agreement in which the Distributor is required to purchase a minimum volume of fuel annually. Sunoco LP expects to recognize this revenue in accordance with the contract as Sunoco LP transfers control of the product to the customer. However, in case of annual shortfall Sunoco LP will recognize the amount payable by the Distributor ratably over the remaining period associated with the shortfall. The transaction price of the contract is variable in nature, fluctuating based on market conditions. The Partnership has elected to take the practical expedient not to estimate the amount of variable consideration allocated to wholly unsatisfied performance obligations.

In some contractual arrangements, Sunoco LP grants dealers a franchise license to operate Sunoco LP’s convenience stores over the life of a franchise agreement. In return for the grant of the convenience store license, the dealer makes a one-time nonrefundable franchise fee payment to Sunoco LP plus sales based royalties payable to Sunoco LP at a contractual rate during the period of the franchise agreement. Under the requirements of ASC Topic 606, the franchise license is deemed to be a symbolic license for which recognition of revenue over time is the most appropriate measure of progress toward complete satisfaction of the performance obligation. Revenue from this symbolic license is recognized evenly over the license period.

As of March 31, 2018, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations is $37.3 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	$ 3,574	$ 4,788	$ 4,244	$ 24,707	$ 37,313

Costs to Obtain or Fulfill a Contract

Sunoco LP recognizes an asset from the costs incurred to obtain a contract (e.g. sales commissions) only if it expects to recover those costs. On the other hand, the costs to fulfill a contract are capitalized if the costs are specifically identifiable to a contract, would result in enhancing resources that will be used in satisfying performance obligations in future and are expected to be recovered. These capitalized costs are recorded as a part of Other Assets and are amortized on a systematic basis consistent with the pattern of transfer of the goods or services to which such costs relate. The amount of amortization expense that the Partnership recognized for the period ended March 31, 2018 was $3 million. Sunoco LP has also made a policy election of expensing the costs to obtain a contract, as and when they are incurred, in cases where the expected amortization period is one year or less.

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.

- *Incremental costs of obtaining a contract:* The Partnership generally expenses sales commissions when incurred because the amortization period would have been less than one year. We record these costs within general and administrative expenses. The Partnership elected to expense the incremental costs of obtaining a contract when the amortization period for such contracts would have been one year or less.

- *Shipping and handling costs:* The Partnership elected to account for shipping and handling activities that occur after the customer has obtained control of a good as fulfillment activities (i.e., an expense) rather than as a promised service.

- *Measurement of transaction price:* The Partnership has elected to exclude from the measurement of transaction price all taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Partnership from a customer, for e.g. sales tax, value added tax etc.

- *Variable consideration of wholly unsatisfied performance obligations:* The Partnership has elected to exclude the estimate of variable consideration to the allocation of wholly unsatisfied performance obligations.

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 operations and operational gas sales on our interstate transportation and storage operations. 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 operations 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 futures and swaps to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales and transportation costs in our retail marketing operations. 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 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 operations 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 operations, 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	(4,540)	2018-2019	(4,390)	2018-2019
Forward Physical Contracts	(224,178)	2018-2020	(145,105)	2018-2020
Natural Gas Liquid/Crude (MBbls) – Forwards/Swaps	38,874	2018-2019	6,744	2018-2019
Refined Products (MBbls) – Futures	(871)	2018-2019	(3,901)	2018-2019
Corn (Bushels) – Futures	(780,000)	2018	1,870,000	2018
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 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 a term 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 ETP'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, ETP may at times require collateral under certain circumstances to mitigate credit risk as necessary. ETP also implements the use of industry standard commercial agreements which allow for the netting of positive and negative exposures associated with transactions executed under a single commercial agreement. Additionally, ETP utilizes master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty or affiliated group of counterparties.

ETP's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrials, oil and gas producers, motor fuel distributors, municipalities, utilities and midstream companies. ETP's overall exposure may be affected positively or negatively by macroeconomic factors or regulatory changes that could impact its 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.

ETP 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 ETP on or about the settlement date for non-exchange traded derivatives, and ETP exchanges 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	89	45	(144)	(58)
Interest rate derivatives	—	—	(167)	(219)
	255	307	(517)	(558)
Total derivatives	$ 255	$ 321	$ (517)	$ (560)

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)	89	45	(144)	(58)
Broker cleared derivative contracts	Other current assets (liabilities)	166	276	(206)	(283)
Total gross derivatives		255	321	(517)	(560)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(63)	(21)	63	21
Counterparty netting	Other current assets (liabilities)	(165)	(263)	165	263
Total net derivatives		$ 27	$ 37	$ (289)	$ (276)

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

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

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness	
		Three Months Ended 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	(71)	2
Interest rate derivatives	Gains on interest rate derivatives	52	5
Embedded derivatives	Other, net	—	1
Total		$ (2)	$ 19

13. RELATED PARTY TRANSACTIONS

Revenues reported in ETE's consolidated statements of operations included sales with affiliates of $102 million and $50 million during the three months ended March 31, 2018 and 2017, respectively.

14. REPORTABLE SEGMENTS

Our financial statements reflect the following reportable business segments:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Sunoco LP, including the consolidated operations of Sunoco LP;
- Investment in Lake Charles LNG, including the operations of Lake Charles LNG; and
- Corporate and Other, including the following:
  - activities of the Parent Company; and
  - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

The Investment in Sunoco LP segment reflects the results of Sunoco LP and the legacy Sunoco, Inc. retail business for the periods presented.

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, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for unconsolidated affiliates based on the Partnership's proportionate ownership and amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations.

The following tables present financial information by segment:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017*
Segment Adjusted EBITDA:		
Investment in ETP	$ 1,881	$ 1,445
Investment in Sunoco LP	109	155
Investment in Lake Charles LNG	43	44
Corporate and Other	1	(13)
Adjustments and Eliminations	(32)	(54)
Total	2,002	1,577
Depreciation, depletion and amortization	(665)	(628)
Interest expense, net	(466)	(473)
Gains on interest rate derivatives	52	5
Non-cash compensation expense	(23)	(27)
Unrealized gains (losses) on commodity risk management activities	(87)	69
Losses on extinguishments of debt	(106)	(25)
Inventory valuation adjustments	25	(13)
Equity in earnings of unconsolidated affiliates	79	87
Adjusted EBITDA related to unconsolidated affiliates	(156)	(185)
Adjusted EBITDA related to discontinued operations	20	(31)
Other, net	41	12
Income from continuing operations before income tax benefit (expense)	716	368
Income tax benefit (expense) from continuing operations	10	(38)
Income from continuing operations	726	330
Loss from discontinued operations, net of tax	(237)	(11)
Net income	$ 489	$ 319

* As adjusted. See Note 1.

	March 31, 2018	December 31, 2017
Assets:		
Investment in ETP	$ 77,495	$ 77,965
Investment in Sunoco LP	4,919	8,344
Investment in Lake Charles LNG	1,677	1,646
Corporate and Other	674	598
Adjustments and Eliminations	(1,856)	(2,307)
Total assets	$ 82,909	$ 86,246

	Three Months Ended March 31,	
	2018	2017*
Revenues:		
Investment in ETP:		
Revenues from external customers	$ 8,085	$ 6,807
Intersegment revenues	195	88
	8,280	6,895
Investment in Sunoco LP:		
Revenues from external customers	3,748	2,805
Intersegment revenues	1	3
	3,749	2,808
Investment in Lake Charles LNG:		
Revenues from external customers	49	49
Adjustments and Eliminations	(196)	(91)
Total revenues	$ 11,882	$ 9,661

* As adjusted. See Note 1.

The following tables provide revenues, grouped by similar products and services, for our reportable segments. These amounts include intersegment revenues for transactions between ETP, Sunoco LP and Lake Charles LNG.

Investment in ETP

	Three Months Ended March 31,	
	2018	2017*
Intrastate Transportation and Storage	$ 817	$ 768
Interstate Transportation and Storage	313	231
Midstream	440	565
NGL and refined products transportation and services	2,458	2,118
Crude oil transportation and services	3,731	2,575
All Other	521	638
Total revenues	8,280	6,895
Less: Intersegment revenues	195	88
Revenues from external customers	$ 8,085	$ 6,807

* As adjusted. See Note 1.

The amounts included in ETP's NGL and refined products transportation and services operation and the crude oil transportation and services operation have been retrospectively adjusted as a result of the Sunoco Logistics Merger.

Investment in Sunoco LP

	Three Months Ended March 31,	
	2018	2017
Retail operations	$ 610	$ 511
Wholesale operations	3,139	2,297
Total revenues	3,749	2,808
Less: Intersegment revenues	1	3
Revenues from external customers	$ 3,748	$ 2,805

Investment in Lake Charles LNG

Lake Charles LNG’s revenues for all periods presented were related to LNG terminalling.

15. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION

Following are the financial statements of the Parent Company, which are included to provide additional information with respect to the Parent Company's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS
(unaudited)

	March 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable from related companies	103	65
Other current assets	1	1
Total current assets	105	67
Property, plant and equipment, net	27	27
Advances to and investments in unconsolidated affiliates	5,805	6,082
Goodwill	9	9
Other non-current assets, net	8	8
Total assets	$ 5,954	$ 6,193
LIABILITIES AND PARTNERS' DEFICIT		
Current liabilities:		
Accounts payable to related companies	$ 1	$ —
Interest payable	78	66
Accrued and other current liabilities	8	4
Total current liabilities	87	70
Long-term debt, less current maturities	6,386	6,700
Long-term notes payable – related companies	658	617
Other non-current liabilities	3	2
Commitments and contingencies		
Partners' deficit:		
General Partner	(3)	(3)
Limited Partners:		
Common Unitholders	(1,696)	(1,643)
Series A Convertible Preferred Units	519	450
Total partners' deficit	(1,180)	(1,196)
Total liabilities and partners' deficit	$ 5,954	$ 6,193

STATEMENTS OF OPERATIONS
(unaudited)

	Three Months Ended March 31,	
	2018	2017
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$ (2)	$ (13)
OTHER INCOME (EXPENSE):		
Interest expense, net	(86)	(83)
Equity in earnings of unconsolidated affiliates	448	361
Losses on extinguishments of debt	—	(25)
Other, net	3	(1)
NET INCOME	363	239
General Partner's interest in net income	1	1
Convertible Unitholders' interest in income	21	6
Limited Partners' interest in net income	$ 341	$ 232

STATEMENTS OF CASH FLOWS
(unaudited)

	Three Months Ended March 31,	
	2018	2017
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 241	$ 251
CASH FLOWS FROM INVESTING ACTIVITIES		
Contributions to unconsolidated affiliate	—	(860)
Sunoco LP Series A Preferred Units redemption	300	—
Net cash provided by (used in) investing activities	300	(860)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings	54	2,017
Principal payments on debt	(370)	(1,733)
Proceeds from affiliate	41	43
Distributions to partners	(266)	(251)
Units issued for cash	—	568
Debt issuance costs	—	(34)
Net cash provided by (used in) financing activities	(541)	610
CHANGE IN CASH AND CASH EQUIVALENTS	—	1
CASH AND CASH EQUIVALENTS, beginning of period	1	2
CASH AND CASH EQUIVALENTS, end of period	$ 1	$ 3

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 included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on February 23, 2018. 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.

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ETE" mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP, Sunoco LP and Lake Charles LNG. References to the "Parent Company" mean Energy Transfer Equity, L.P. on a stand-alone basis.

OVERVIEW

At March 31, 2018, subsequent to Sunoco LP's repurchase of the 12 million Sunoco LP Series A Preferred Units held by ETE, our interests in ETP and Sunoco LP consisted of 100% of the respective general partner interests and IDRs, as well as approximately 27.5 million ETP common units and approximately 2.3 million Sunoco LP common units. Additionally, ETE owns 100 ETP Class I Units, which are currently not entitled to any distributions.

Our reportable segments are as follows:

- Investment in ETP, including the consolidated operations of ETP;
- Investment in Sunoco LP, including the consolidated operations of Sunoco LP;
- Investment in Lake Charles LNG, including the operations of Lake Charles LNG; and
- Corporate and Other, including the following:
  - activities of the Parent Company; and
  - the goodwill and property, plant and equipment fair value adjustments recorded as a result of the 2004 reverse acquisition of Heritage Propane Partners, L.P.

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.

ETP Series C Preferred Units Issuance

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

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 MBbl refrigerated ethane storage tank, a 175 MBbl/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 MBbl/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 ("VLECs") 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.

USAC Transaction

On April 2, 2018, 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 representing limited partner interests in USAC ("USAC Common Units") for cash consideration equal to $250 million. Concurrently, 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 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, ETE's consolidated financial statements will reflect USAC as a consolidated subsidiary. At the time our consolidated financial statements were issued, the initial accounting for this business combination was incomplete; therefore, certain required disclosures have not been included herein.

The assets and liabilities of CDM and CDM E&T have not been reflected as held for sale, nor have CDM's or CDM E&T's results been reflected as discontinued operations in these financial statements.

Sunoco LP Series A Preferred Units

On January 25, 2018, Sunoco LP redeemed all outstanding Sunoco LP Series A Preferred Units held by ETE for an aggregate redemption amount of approximately $313 million. The redemption amount includes the original consideration of $300 million and a 1% call premium plus accrued and unpaid quarterly distributions.

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.

Sunoco LP Private Offering of Senior Notes

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028. Sunoco LP used the proceeds from the private offering, along with proceeds from the 7-Eleven Transaction, to: 1) redeem in full its previously existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020, and $800 million in aggregate principal amount of 6.375% senior notes due 2023; 2) repay in full and terminate its term loan; 3) pay all closing costs in connection with the 7-Eleven transaction; 4) redeem the outstanding Sunoco LP Series A Preferred Units; and 5) repurchase 17,286,859 common units owned by ETP.

Sunoco LP Acquisitions

On April 3, 2018, a subsidiary of Sunoco LP entered into an asset purchase agreement with Superior Plus Energy Services, Inc. ("Superior"), a New York Corporation, pursuant to which it agreed to acquire certain wholesale fuel distribution assets and related terminal assets from Superior for approximately $40 million plus working capital adjustments. The assets consist of a network of approximately 100 dealers, several hundred commercial contracts and three terminals, which are connected to major pipelines serving the Upstate New York market. The transaction closed on April 25, 2018.

On January 4, 2018, Sunoco LP entered into an asset purchase agreement with 7-Eleven and SEI Fuel, pursuant to which the Partnership agreed to acquire 26 retail fuel outlets from 7-Eleven and SEI Fuel for approximately $50 million. The transaction closed on April 2, 2018.

Sunoco LP Convenience Store and Real Estate Sales

On April 1, 2018, Sunoco LP completed the conversion of 207 retail sites located in certain West Texas, Oklahoma and New Mexico markets to a single commission agent. Under the commission agent model, Sunoco LP owns, prices and sells fuel at the sites, paying the commission agent a fixed cents-per-gallon commission and receives rental income from the commission agent. The commission agent conducts all operations related to the convenience stores and related restaurant locations.

On January 23, 2018, Sunoco LP closed on an asset purchase agreement with 7-Eleven, Inc., a Texas corporation ("7-Eleven") and SEI Fuel Services, Inc., a Texas corporation and wholly-owned subsidiary of 7-Eleven. Under the agreement, Sunoco LP sold a portfolio of approximately 1,030 company-operated retail fuel outlets in 19 geographic regions, together with ancillary businesses and related assets, including the proprietary Laredo Taco Company brand, for an aggregate purchase price of $3.2 billion.

On January 18, 2017, with the assistance of a third-party brokerage firm, Sunoco LP launched a portfolio optimization plan to market and sell 97 real estate assets. Real estate assets included in this process are company-owned locations, undeveloped greenfield sites and other excess real estate. Properties are located in Florida, Louisiana, Massachusetts, Michigan, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas and Virginia. The properties are being sold through a sealed-bid. Of the 97 properties, 47 have been sold, one is under contract to be sold, and eight continue to be marketed by the third-party brokerage firm. Additionally, 32 were sold to 7-Eleven and nine are part of the approximately 207 retail sites located in certain West Texas, Oklahoma, and New Mexico markets which will be operated by a commission agent.

Quarterly Cash Distribution

In April 2018, ETE announced its quarterly distribution of $0.305 per unit ($1.22 annualized) on ETE common units for the quarter ended March 31, 2018.

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 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, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities include unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries based on 100% of the subsidiaries' results of operations.

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:			
Investment in ETP	$ 1,881	$ 1,445	$ 436
Investment in Sunoco LP	109	155	(46)
Investment in Lake Charles LNG	43	44	(1)
Corporate and Other	1	(13)	14
Adjustments and Eliminations	(32)	(54)	22
Total	2,002	1,577	425
Depreciation, depletion and amortization	(665)	(628)	(37)
Interest expense, net of interest capitalized	(466)	(473)	7
Gains on interest rate derivatives	52	5	47
Non-cash compensation expense	(23)	(27)	4
Unrealized gains (losses) on commodity risk management activities	(87)	69	(156)
Losses on extinguishments of debt	(106)	(25)	(81)
Inventory valuation adjustments	25	(13)	38
Equity in earnings of unconsolidated affiliates	79	87	(8)
Adjusted EBITDA related to unconsolidated affiliates	(156)	(185)	29
Adjusted EBITDA related to discontinued operations	20	(31)	51
Other, net	41	12	29
Income from continuing operations before income tax benefit (expense)	716	368	348
Income tax benefit (expense) from continuing operations	10	(38)	48
Income from continuing operations	726	330	396
Loss from discontinued operations, net of income taxes	(237)	(11)	(226)
Net income	$ 489	$ 319	$ 170

* As adjusted.

See the detailed discussion of Segment Adjusted EBITDA in “Segment Operating Results” below.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased for the three months ended March 31, 2018 compared to the same period last year increased primarily due to additional depreciation and amortization from assets recently placed in service.

Interest Expense, Net. Interest expense for the three months ended March 31, 2018 decreased primarily due to the following:

- a decrease of $24 million of expense recognized by Sunoco LP for the three months ended March 31, 2018 compared to the same period in the prior year primarily due to Sunoco LP’s repayment of its term loan and decreased borrowings under its revolving credit facility; partially offset by

- an increase of $14 million of expense recognized by ETP primarily attributable to increases in long-term debt, including increased borrowings under ETP’s revolving credit facilities; and

- an increase of $3 million of expense recognized by the Parent company primarily attributable to increases in variable interest rates.

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 the segment results below.

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded during the three months ended March 31, 2018 and 2017, for the inventory associated with ETP's crude oil transportation and service and ETP's NGL and refined products transportation and services inventories as a result of commodity price changes during the respective periods.

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

Adjusted EBITDA Related to Discontinued Operations. Amounts were related to the operations of Sunoco LP's retail business that was classified as held for sale.

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 a deferred benefit adjustment during three months ended March 31, 2018 as the result of a state statutory rate reduction.

Segment Operating Results

Investment in ETP

	Three Months Ended March 31,		
	2018	2017	Change
Revenues	$ 8,280	$ 6,895	$ 1,385
Cost of products sold	5,988	5,050	938
Segment margin	2,292	1,845	447
Unrealized (gains) losses on commodity risk management activities	87	(64)	151
Operating expenses, excluding non-cash compensation expense	(587)	(485)	(102)
Selling, general and administrative expenses, excluding non-cash compensation expense	(100)	(100)	—
Adjusted EBITDA related to unconsolidated affiliates	185	239	(54)
Other, net	4	10	(6)
Segment Adjusted EBITDA	$ 1,881	$ 1,445	$ 436

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to the Investment in ETP segment increased due to the net impact of the following:

- an increase of $23 million in ETP's intrastate transportation and storage operations resulting from 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 a realized adjustment to the Bammel storage inventory and a decrease of $7 million in transportation fees due to renegotiated contracts resulting in lower billed volumes;

- an increase of $58 million in ETP's interstate transportation and storage operations due to an increase of $49 million due to the partial in service of the Rover pipeline in August 2017 which reflected increases of $82 million in revenues, $26 million in operating expenses and $7 million in general and administrative expenses;

- an increase of $57 million in ETP's midstream operations primarily due to a $43 million increase in non-fee based margins due to higher realized crude oil and NGL prices and a $13 million increase in fee-based revenues due to increased volumes in the Permian and Northeast regions offset by declines in Ark-La-Tex, North Texas and the Mid-Continent/Panhandle regions;

- an increase of $70 million in ETP's NGL and refined products transportation and services operations due to an increase of $33 million in transportation volume, primarily due to higher volumes on Texas NGL pipelines and the ramp-up of volumes on the Mariner East system; an increase of $25 million in marketing margin due to gains from optimizing sales of purity product from the Mont Belvieu fractionators; and 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 ETP’s Mont Belvieu fractionation facility and a $7 million increase from blending gains as a result of improved market pricing;

- an increase of $277 million in ETP’s crude oil transportation and services operations due to a $222 million increase in margin resulting primarily from placing ETP’s Bakken pipeline in service in the second quarter of 2017 as well as the addition of Permian Express Partners joint venture assets in February 2017 and November 2017; a $25 million increase in margin from existing transportation assets due to increased volumes throughout the system; an $85 million increase in margin (excluding $43 million in unrealized losses on commodity risk management activities) from ETP’s crude oil acquisition and marketing segment primarily resulting from more favorable market price differentials from West Texas and Gulf Coast markets; and a $7 million increase in margin from higher ship loading and throughput fees at ETP’s Nederland terminal due to an increase in exports. These increases in margin were offset by an increase of $55 million in operating expenses, primarily due to assets recently acquired or placed in service; and

- a decrease of approximately $49 million in ETP’s all other operations, due to a decrease of $54 million in Adjusted EBITDA related to unconsolidated affiliates, reflecting a decrease of $30 million from ETP’s investment in PES due to lower earnings and a decrease of $25 million from ETP’s investment in Sunoco LP primarily due to Sunoco LP’s sale of retail assets, as well as a decrease in ETP’s ownership interest in Sunoco LP subsequent to the repurchase of common units by Sunoco LP in February 2018; and an increase of $10 million in operating expenses primarily attributable to an increase of $8 million in the compression business. These decreases in adjusted EBITDA were partially 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.

Investment in Sunoco LP

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Change
Revenues	$ 3,749	$ 2,808	$ 941
Cost of products sold	3,453	2,552	901
Segment margin	296	256	40
Unrealized gains (losses) on commodity risk management activities	—	(5)	5
Operating expenses, excluding non-cash compensation expense	(113)	(112)	(1)
Selling, general and administrative, excluding non-cash compensation expense	(32)	(28)	(4)
Inventory fair value adjustments	(25)	13	(38)
Adjusted EBITDA from discontinued operations	(20)	31	(51)
Other	3	—	3
Segment Adjusted EBITDA	$ 109	$ 155	$ (46)

Segment Adjusted EBITDA. For the three months ended March 31, 2018 compared to the same period last year, Segment Adjusted EBITDA related to the Investment in Sunoco LP segment decreased due to the net impacts of the following:

- a decrease in Adjusted EBITDA from discontinued operations primarily attributable to Sunoco LP’s retail divestment in January 2018; and

- an increase in general and administrative expenses and other operating expenses of $4 million primarily attributable to higher payroll expenses; offset by

- an increase in segment margin of $40 million primarily due to inventory adjustments. The change in segment margin also reflected an $8 million increase due to higher gross profit per gallon on retail motor fuel sales, offset by a decrease of $7 million from merchandise, rental and other.

Investment in Lake Charles LNG

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Change
Revenues	$ 49	$ 49	$ —
Operating expenses, excluding non-cash compensation expense	(5)	(5)	—
Selling, general and administrative, excluding non-cash compensation expense	(1)	—	(1)
Segment Adjusted EBITDA	$ 43	$ 44	$ (1)

Lake Charles LNG derives all of its revenue from a long-term contract with BG Group plc.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Parent Company Only

The Parent Company's principal sources of cash flow are derived from its direct and indirect investments in the limited partner and general partner interests in ETP and Sunoco LP and cash flows from the operations of Lake Charles LNG. The amount of cash that ETP and Sunoco LP distribute to their respective partners, including the Parent Company, each quarter is based on earnings from their respective business activities and the amount of available cash, as discussed below. In connection with previous transactions, we have relinquished a portion of our incentive distributions to be received from ETP and Sunoco LP, see additional discussion under "Cash Distributions."

The Parent Company's primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. The Parent Company currently expects to fund its short-term needs for such items with cash flows from its direct and indirect investments in ETP, Sunoco LP and Lake Charles LNG. The Parent Company distributes its available cash remaining after satisfaction of the aforementioned cash requirements to its Unitholders on a quarterly basis.

The Parent Company expects ETP, Sunoco LP and Lake Charles LNG and their respective subsidiaries to utilize their resources, along with cash from their operations, to fund their announced growth capital expenditures and working capital needs; however, the Parent Company may issue debt or equity securities from time to time, as it deems prudent to provide liquidity for new capital projects of its subsidiaries or for other partnership purposes.

ETP

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 the control of ETP's management.

ETP currently expects 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 ETP's proportionate ownership of the Bakken, Rover and Bayou Bridge pipeline projects.

The assets used in ETP's 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, ETP does not have any significant financial commitments for maintenance capital expenditures in its businesses. From time to time ETP experiences increases in pipe costs due to a number of reasons, including but not limited to, delays from mills, limited selection of mills capable of producing large diameter pipe in a timely manner, higher steel prices and other factors beyond ETP's control. However, ETP included these factors in its anticipated growth capital expenditures for each year.

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

Sunoco LP

Sunoco LP'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 the control of Sunoco LP's management.

Sunoco LP currently expects to spend approximately $90 million on growth capital and $40 million on maintenance capital for the full year 2018.

Cash Flows

Our cash flows may change in the future due to a number of factors, some of which we cannot control. These factors include regulatory changes, the price of our subsidiaries' 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 acquisition 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 ETP has 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 price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchases 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 $2.14 billion as compared to $771 million for 2017. Net income was $489 million and $319 million for 2018 and 2017, respectively. The difference between net income and the net cash provided by operating activities for the three months ended March 31, 2018 and 2017, primarily consisted of non-cash items totaling $611 million and $589 million, respectively, and net changes in operating assets and liabilities of $757 million and $185 million, respectively.

The non-cash activity in 2018 and 2017 consisted primarily of depreciation, depletion and amortization of $665 million and $628 million, respectively, equity in earnings of unconsolidated affiliates of $79 million and $87 million, respectively, inventory valuation adjustments of $25 million and $13 million, respectively, deferred income tax benefit of $12 million and deferred income tax expense of $37 million, respectively, losses on extinguishments of debt of $106 million and $25 million, respectively, and non-cash compensation expense of $23 million and $27 million, respectively.

Cash paid for interest, net of interest capitalized, was $383 million and $491 million for the three months ended March 31, 2018 and 2017, respectively.

Capitalized interest was $81 million and $60 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, and cash contributions to our joint ventures. Changes in capital expenditures between periods primarily result from increases or decreases in growth capital expenditures to fund their respective 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 $1.70 billion as compared to cash provided by investing activities $244 million for 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 $1.72 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2017 of $1.40 billion. In 2018 and 2017, we paid net cash for acquisitions of $5 million and $330 million, respectively, including the acquisition of a noncontrolling interest. In 2017, we had proceeds from the sale of a minority interest in the Bakken Pipeline of $2.0 billion.

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 acquisitions and growth capital expenditures. Distributions increase between the periods based on increases in the number of common units outstanding or increases in the distribution rate.

Three months ended March 31, 2018 compared to three months ended March 31, 2017. Cash used in financing activities during 2018 was $2.97 billion as compared to cash used in financing activities of $1.21 billion for 2017. In 2018, ETE received $20 million in net proceeds from offerings of ETE common units and subsidiary common units as compared to $867 million in 2017. During 2018, we had a consolidated net decrease in our debt level of $1.91 billion as compared to a net decrease of $809 million for 2017. In 2017, we paid net proceeds on affiliates notes in the amount of $268 million. We have paid distributions of $266 million and $251 million to our partners in 2018 and in 2017, respectively. Our subsidiaries have paid distributions to noncontrolling interest of $893 million and $752 million in 2018 and 2017, respectively. We paid $117 million and $53 million in debt issuance costs in 2018 and 2017, respectively. In addition, we have received capital contributions of $229 million in cash from noncontrolling interests in 2018 compared to $106 million in 2017.

Discontinued Operations

Cash flows from discontinued operations reflect cash flows related to Sunoco LP’s retail divestment.

Three months ended March 31, 2018 compared to three months ended March 31, 2017

Cash provided by discontinued operations was $2.74 billion for the three months ended March 31, 2018 resulting from cash used in operating activities of $485 million, cash provided by investing activities of $3.21 billion and changes in cash included in current assets held for sale of $11 million. Cash provided by discontinued operations was $80 million for the three months ended March 31, 2017 resulting from cash provided by operating activities of $121 million, cash used in investing activities of $40 million and changes in cash included in current assets held for sale of $1 million.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	March 31, 2018	December 31, 2017
Parent Company Indebtedness:		
ETE Senior Notes due October 2020	$ 1,187	$ 1,187
ETE Senior Notes due March 2023	1,000	1,000
ETE Senior Notes due January 2024	1,150	1,150
ETE Senior Notes due June 2027	1,000	1,000
ETE Senior Secured Term Loan due February 2, 2024	1,220	1,220
ETE Senior Secured Revolving Credit Facility due March 24, 2022	873	1,188
Subsidiary Indebtedness:		
ETP Senior Notes	27,005	27,005
Transwestern Senior Notes	575	575
Panhandle Senior Notes	785	785
Sunoco LP Senior Notes, Term Loan and lease-related obligation	2,311	3,556
Credit Facilities and Commercial Paper:		
ETP $4.0 billion Revolving Credit Facility due December 2022 (1)	2,756	2,292
ETP $1.0 billion 364-Day Credit Facility due November 2018 (2)	—	50
Bakken Project $2.50 billion Credit Facility due August 2019	2,500	2,500
Sunoco LP $1.5 billion Revolving Credit Facility due September 2019	—	765
Other Long-Term Debt	8	8
Unamortized premiums and fair value adjustments, net	49	50
Deferred debt issuance costs	(231)	(247)
Total	42,188	44,084
Less: Current maturities of long-term debt	409	413
Long-term debt and notes payable, less current maturities	$ 41,779	$ 43,671

(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.

Sunoco LP Senior Notes and Term Loan

On January 23, 2018, Sunoco LP completed a private offering of $2.2 billion of senior notes, comprised of $1.0 billion in aggregate principal amount of 4.875% senior notes due 2023, $800 million in aggregate principal amount of 5.500% senior notes due 2026 and $400 million in aggregate principal amount of 5.875% senior notes due 2028. Sunoco LP used the proceeds from the private offering, along with proceeds from the closing of the asset purchase agreement with 7-Eleven to:

i. redeem in full its existing senior notes, comprised of $800 million in aggregate principal amount of 6.250% senior notes due 2021, $600 million in aggregate principal amount of 5.500% senior notes due 2020, and $800 million in aggregate principal amount of 6.375% senior notes due 2023;
ii. repay in full and terminate its term loan;
iii. pay all closing costs in connection with the 7-Eleven transaction;
iv. redeem the outstanding Sunoco LP Series A Preferred Units; and
v. repurchase 17,286,859 common units owned by ETP.

ETE Revolving Credit Facility

Pursuant to ETE’s revolving credit agreement, which matures on March 24, 2022, the lenders have committed to provide advances up to an aggregate principal amount of $1.5 billion at any one time outstanding, and the Parent Company has the option to request increases in the aggregate commitments by up to $500 million in additional commitments.

As of March 31, 2018, borrowings of $873 million were outstanding under the Parent Company revolving credit facility and the amount available for future borrowings was $627 million.

ETP Five-Year Credit Facility

ETP's revolving credit facility (the "ETP Five-Year Credit Facility") allows for unsecured borrowings up to $4.0 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 $6.0 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 $1.0 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%.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.50 billion revolving credit agreement which matures in September 2019. As of March 31, 2018, the Sunoco LP credit facility had no outstanding borrowings and $8 million in standby letters of credit. The unused availability on the revolver at March 31, 2018 was $1.5 billion.

Covenants Related to Our Credit Agreements

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

CASH DISTRIBUTIONS

Cash Distributions Paid by the Parent Company

Under the Parent Company partnership agreement, the Parent Company will distribute all of its Available Cash, as defined in the partnership agreement, within 50 days following the end of each fiscal quarter. Available Cash generally means, with respect to any quarter, all cash on hand at the end of such quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of our general partner that is necessary or appropriate to provide for future cash requirements.

Distributions declared and/or paid subsequent to December 31, 2017 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017 (1)	February 8, 2018	February 20, 2018	$ 0.3050
March 31, 2018 (1)	May 7, 2018	May 21, 2018	0.3050

(1) Certain common unitholders elected to participate in a plan pursuant to which those unitholders elected to forgo their cash distributions on all or a portion of their common units, and in lieu of receiving cash distributions on these common units for each such quarter, such unitholder received Series A Convertible Preferred Units (on a one-for-one basis for each common unit as to which the participating unitholder elected be subject to this plan) that entitled them to receive a cash distribution of up to $0.11 per Series A Convertible Preferred Unit. The quarter ended March 31, 2018 is the final quarter of participation in the plan.

Distributions declared and/or paid with respect to our Series A Convertible Preferred Units subsequent to December 31, 2017 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017	February 8, 2018	February 20, 2018	$ 0.1100
March 31, 2018	May 7, 2018	May 21, 2018	0.1100

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

	Three Months Ended March 31,	
	2018	2017
Limited Partners	$ 265	$ 250
General Partner interest	1	1
Total Parent Company distributions	$ 266	$ 251

Cash Distributions Received by the Parent Company

The Parent Company's cash available for distributions historically has been primarily generated from its direct and indirect interests in ETP and Sunoco LP. Lake Charles LNG also contributes to the Parent Company's cash available for distributions.

The total amount of distributions to the Parent Company from its limited partner interests, general partner interest and incentive distributions (shown in the period to which they relate) for the periods ended as noted below is as follows:

	Three Months Ended March 31,	
	2018	2017
Distributions from ETP:		
Limited Partner interests	$ 16	$ 15
General partner interest and IDRs	449	381
IDR relinquishments net of Class I Unit distributions	(42)	(157)
Total distributions from ETP	423	239
Distributions from Sunoco LP		
Limited Partner interests	2	2
IDRs	18	21
Total distributions from Sunoco LP	20	23
Total distributions received from subsidiaries	$ 443	$ 262

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

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

ETE may agree to relinquish its rights to additional amounts of incentive distributions from ETP or Sunoco LP in future periods without the consent of ETE unitholders.

Cash Distributions Paid by Subsidiaries

Certain of our subsidiaries are required by their respective partnership agreements to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by the board of directors of their respective general partners.

Cash Distributions Paid by ETP

Under ETP’s limited partnership agreement, within 45 days after the end of each quarter, ETP 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 ETP’s partnership agreement. The general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct ETP's business. ETP 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 declared and/or paid by ETP 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 ETP preferred units declared and paid by ETP subsequent to December 31, 2017 were as follows:

			Distribution per ETP 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 amount of distributions declared during the periods presented were as follows (all from Available Cash from ETP’s 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

Cash Distributions Paid by Sunoco LP

Distributions declared and/or paid by Sunoco LP subsequent to December 31, 2017 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2017	February 6, 2018	February 14, 2018	$ 0.8255
March 31, 2018	May 7, 2018	May 15, 2018	0.8255

The total amounts of Sunoco LP distributions declared for the periods presented (all from Available Cash from Sunoco LP's 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	$ 45	$ 44
Common and subordinated units held by ETP	21	36
Common and subordinated units held by ETE	2	2
General Partner interest and incentive distributions	18	21
Total distributions declared	$ 86	$ 103

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 the accompanying unaudited interim consolidated financial statements included in "Item 1. Financial Statements" 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 in our Annual Report on Form 10-K for the year ended December 31, 2017, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K 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	(4,540)	1	7	(4,390)	(1)	2
Forward Physical Contracts	(224,178)	1	—	(145,105)	6	41
Natural Gas Liquid/Crude (MBbls) – Forwards/Swaps	38,874	(54)	8	6,744	1	25
Refined Products (MBbls) – Futures	(871)	(2)	11	(3,901)	(27)	4
Corn (Bushels) – Futures	(780,000)	—	—	1,870,000	—	—
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 and our subsidiaries had $7.95 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $80 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 a term 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 ETP's $1.50 billion of interest rate swaps whereby it pays a floating rate and receives 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 President ("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 Topic 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 Topic 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 Form 10-K for the year ended December 31, 2017 and Note 10 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Equity, 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.

ETP's 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 ETP from fully recovering its costs.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of ETP's 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.

ETP is required to file tariff rates (also known as recourse rates) with the FERC that shippers may pay for interstate natural gas transportation services. ETP 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 ETP 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 ETP and find that its rates were not just and reasonable or unduly discriminatory, the maximum rates ETP is permitted to charge may be reduced and the reduction could have an adverse effect on ETP's revenues and results of operations.

The costs of ETP's interstate pipeline operations may increase and ETP may not be able to recover all of those costs due to FERC regulation of its rates. If ETP proposes to change its tariff rates, ETP proposed rates may be challenged by the FERC or third parties, and the FERC may deny, modify or limit its proposed changes if ETP is unable to persuade the FERC that changes would result in just and reasonable rates that are not unduly discriminatory. ETP 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 ETP may be constrained by competitive factors from charging its tariff rates.

To the extent ETP's costs increase in an amount greater than its revenues increase, or there is a lag between ETP's cost increases and its ability to file for and obtain rate increases, its 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. ETP cannot guarantee that its interstate pipelines will be able to recover all of its 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.

ETP cannot predict the outcome of the NOPR, but the cost of service rates ETP is permitted to charge its customers for transportation services could be impacted if any of its 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 ETP to establish new tariff rates for its 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 ETP's current cost of services rates which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders.

ETP's interstate natural gas pipelines are subject to laws, regulations and policies governing terms and conditions of service, which could adversely affect its 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 ETP's interstate natural gas pipelines, including:

Compliance with these requirements can be costly and burdensome. In addition, ETP cannot guarantee that the FERC will authorize tariff changes and other activities ETP 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 ETP's access to capital markets or may impair the ability of its 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. ETP is unable to predict what, if any, changes may be proposed as a result of the Pipeline Certification NOI that will affect its natural gas pipeline business or when such proposals, if any, might become effective. ETP does not expect that any change in this policy would affect it 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 ETP to recover the full amount of increases in the costs of its crude oil, NGL and products pipeline operations.

Transportation provided on ETP’s 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 ETP proposes 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 ETP’s ability to set rates based on its 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 ETP’s 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 ETP’s 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 ETP 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 ETP’s 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. ETP cannot predict the outcome of the 2020 liquids pipeline index five-year review, but the rates ETP is permitted to charge its customers for cost of service based liquids transportation services could be impacted. If FERC requires ETP to establish new tariff rates for its 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 ETP’s financial position, results of operations and ability to make cash distributions to its unitholders.

ITEM 5. OTHER INFORMATION

ETE is including information in this Part II. Item 5. in order to: (i) file Exhibit 99.1 hereto to replace in its entirety the section under the heading “Material U.S. Federal Income Tax Consequences” that appears in the prospectus supplement filed with the SEC by the Partnership on March 22, 2017 (the “ATM Prospectus”); (ii) file Exhibit 99.2 hereto to replace in its entirety the section under the heading “Material U.S. Federal Income Tax Consequences” that appears in the Partnership’s Registration Statement on Form S-3 (Registration File No. 333-215893), as filed with the SEC on February 6, 2017 (as so filed and as so amended, the “PIPE Registration Statement”); and (iii) provide the legal opinion of Latham & Watkins LLP relating to certain tax matters, a copy of which is filed as (a) Exhibit 8.1 hereto in connection with the ATM Prospectus and (b) Exhibit 8.2 hereto in connection with the PIPE Registration Statement.

ITEM 6. EXHIBITS

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

Exhibit Number	Description
2.1	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 2.1 to the Current Report on Form 8-K filed January 16, 2018)
2.2	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 2.2 to the Current Report on Form 8-K filed January 16, 2018)
8.1*	Opinion of Latham & Watkins LLP relating to tax matters
8.2*	Opinion of Latham & Watkins LLP relating to tax matters
10.1	Equity Restructuring Agreement, dated as of January 15, 2018, by and among Energy Transfer Equity, L.P., USA Compression Partners, LP and USA Compression GP, LLC. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 16, 2018)
10.2	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)
12.1*	Computation of Ratio of Earnings to Fixed Charges.
23.1*	Consent of Latham & Watkins LLP (included in Exhibit 8.1 hereto)
23.2*	Consent of Latham & Watkins LLP (included in Exhibit 8.2 hereto)
31.1*	Certification of President 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 President 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
99.2*	Material U.S. Federal Income Tax Consequences
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definitions Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy 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 EQUITY, L.P.

By: LE GP, LLC, its General Partner

Date: May 10, 2018

By: /s/ Thomas E. Long

Thomas E. Long

Group Chief Financial Officer (duly
authorized to sign on behalf of the registrant)

LATHAM&WATKINS LLP

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May 10, 2018

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

Re: Energy Transfer Equity, L.P.

Ladies and Gentlemen:

We have acted as special tax counsel to Energy Transfer Equity, L.P., a Delaware limited partnership (the "Partnership"), in connection with the proposed offer and sale from time to time by the Partnership of common units representing limited partner interests in the Partnership having an aggregate offering price of up to $1,000,000,000 (the "Units"). The Units are included in a registration statement on Form S-3 under the Securities Act of 1933, as amended (the "Act"), initially filed with the Securities and Exchange Commission (the "Commission") on February 8, 2017 (Registration No. 333-215969) (as so filed and as amended, the "Registration Statement"), and the prospectus supplement dated March 21, 2017, as amended and supplemented through the date hereof (the "Prospectus Supplement"), to the prospectus dated March 2, 2017 (the "Base Prospectus" and together with the Prospectus Supplement, the "Prospectus").

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 Partnership's Registration Statement, the Prospectus and the Partnership's responses to our examinations and inquiries.

In our capacity as special tax counsel to the Partnership, we have, with your consent, 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 that are qualified as to knowledge or belief, without regard to such qualification.

We are opining herein as to the effect on the subject transaction only of the federal income tax laws of the United States and we express no opinion with respect to the applicability thereto, or the effect thereon, of 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. No opinion is expressed as to any matter not discussed herein.

Based on such facts, assumptions and representations and subject to the limitations set forth herein and in the Registration Statement, the Prospectus and the Officer's Certificate, the statements in the Prospectus Supplement under the caption "Material U.S. Federal Income Tax Consequences," insofar as such statements purport to constitute summaries of United States federal income tax law and regulations or legal conclusions with respect thereto, constitute the opinion of Latham & Watkins LLP as to the material U.S. federal income tax consequences of the matters described therein.

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 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 Registration Statement, the Prospectus and the Officer's Certificate, may affect the conclusions stated herein.

This opinion is furnished to you, and is for your use in connection with the transactions set forth in the Registration Statement and the Prospectus. This opinion may not be relied upon by you 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, except that this opinion may be relied upon by persons entitled to rely on it pursuant to applicable provisions of federal securities law.

We hereby consent to the filing of this opinion as an exhibit to the quarterly report on Form 10-Q of the Partnership and to the incorporation by reference of this opinion to the Prospectus Supplement. In giving such consent, we do not thereby admit that we are within the category of persons whose consent is required under Section 7 of the Act or the rules or regulations of the Commission promulgated thereunder.

Very truly yours,

/s/ Latham & Watkins LLP

LATHAM&WATKINS LLP

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Houston, TX 77002
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Barcelona	Moscow
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London	Singapore
Los Angeles	Tokyo
Madrid	Washington, D.C.
Milan	

May 10, 2018

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

Re: Energy Transfer Equity, L.P.

Ladies and Gentlemen:

We have acted as special tax counsel to Energy Transfer Equity, L.P., a Delaware limited partnership (the "Partnership"), in connection with the preparation and filing with the Securities and Exchange Commission (the "Commission") of the Registration Statement on Form S-3 initially filed by the Partnership under the Securities Act of 1933, as amended (the "Act"), on February 3, 2017, as amended and supplemented through the date hereof (the "Registration Statement"), and the prospectus related thereto, as amended and supplemented through the date hereof (the "Prospectus"), for the purpose of registering under the Act common units of the Partnership.

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 Partnership's Registration Statement, the Prospectus and the Partnership's responses to our examinations and inquiries.

In our capacity as special tax counsel to the Partnership, we have, with your consent, 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 that are qualified as to knowledge or belief, without regard to such qualification.

We are opining herein as to the effect on the subject transaction only of the federal income tax laws of the United States and we express no opinion with respect to the applicability thereto, or the effect thereon, of 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. No opinion is expressed as to any matter not discussed herein.

Based on such facts, assumptions and representations and subject to the limitations set forth herein and in the Registration Statement, the Prospectus and the Officer's Certificate, the statements in the Prospectus under the caption "Material U.S. Federal Income Tax Consequences," insofar as such statements purport to constitute summaries of United States federal income tax law and regulations or legal conclusions with respect thereto, constitute the opinion of Latham & Watkins LLP as to the material U.S. federal income tax consequences of the matters described therein.

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 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 Registration Statement, the Prospectus and the Officer's Certificate, may affect the conclusions stated herein.

This opinion is furnished to you, and is for your use in connection with the transactions set forth in the Registration Statement and the Prospectus. This opinion may not be relied upon by you 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, except that this opinion may be relied upon by persons entitled to rely on it pursuant to applicable provisions of federal securities law.

We hereby consent to the filing of this opinion as an exhibit to the quarterly report on Form 10-Q of the Partnership and to the incorporation by reference of this opinion to the Registration Statement. In giving such consent, we do not thereby admit that we are within the category of persons whose consent is required under Section 7 of the Act or the rules or regulations of the Commission promulgated thereunder.

Very truly yours,

/s/ Latham & Watkins LLP

Exhibit 12.1

ENERGY TRANSFER EQUITY, L.P.

Computation of Ratio of Earnings to Fixed Charges

(in millions, except for ratio amounts)

(Unaudited)

	Three Months Ended March 31, 2018
Fixed Charges:	
Interest expense, net	$ 466
Capitalized interest	81
Interest charges included in rental expense	4
Total fixed charges	551
Earnings:	
Income from continuing operations before income tax expense and noncontrolling interest	716
Less: equity in earnings of unconsolidated affiliates	79
Total earnings	637
Add:	
Fixed charges	551
Amortization of capitalized interest	4
Distributed income of equity investees	61
Less:	
Interest capitalized	(81)
Income available for fixed charges	$ 1,172
Ratio of earnings to fixed charges	2.13

Exhibit 31.1

CERTIFICATION OF PRESIDENT (PRINCIPAL EXECUTIVE OFFICER)
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John W. McReynolds, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer Equity, 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 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 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/ John W. McReynolds

John W. McReynolds
President

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 Equity, 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 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 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
Group 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 Equity, 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, John W. McReynolds, President, 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/ John W. McReynolds

John W. McReynolds
President

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

Exhibit 99.1

Material U.S. Federal Income Tax Consequences

The tax consequences to you of an investment in our common units will depend in part on your own tax circumstances. This section should be read in conjunction with the risk factors included under the caption “Tax Risks to Unitholders” in our most recent Annual Report on Form 10-K. This section is a summary of the material U.S. federal income tax consequences that may be relevant to prospective common unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Latham & Watkins LLP, counsel to our general partner and us, insofar as it relates to legal conclusions with respect to matters of U.S. federal income tax law. This section is based upon current provisions of the Internal Revenue Code of 1986, as amended (the “Internal Revenue Code”), existing and proposed Treasury regulations promulgated under the Internal Revenue Code (the “Treasury Regulations”) and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to “us” or “we” are references to Energy Transfer Equity, L.P. and our operating subsidiaries.

The following discussion does not comment on all federal income tax matters affecting us or our unitholders and does not describe the application of the alternative minimum tax that may be applicable to certain unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, entities treated as partnerships for U.S. federal income tax purposes, trusts, nonresident aliens, U.S. expatriates and former citizens or long-term residents of the United States or other unitholders subject to specialized tax treatment, such as banks, insurance companies and other financial institutions, tax-exempt institutions, foreign persons (including, without limitation, controlled foreign corporations, passive foreign investment companies and foreign persons eligible for the benefits of an applicable income tax treaty with the United States), individual retirement accounts (IRAs), real estate investment trusts (REITs) or mutual funds, dealers in securities or currencies, traders in securities, U.S. persons whose “functional currency” is not the U.S. dollar, persons holding their units as part of a “straddle,” “hedge,” “conversion transaction” or other risk reduction transaction, persons subject to special tax accounting rules as a result of any item of gross income with respect to our common units being taken into account in an applicable financial statement and persons deemed to sell their units under the constructive sale provisions of the Internal Revenue Code. In addition, the discussion only comments, to a limited extent, on state, local, and foreign tax consequences. Accordingly, we encourage each prospective common unitholder to consult his own tax advisor in analyzing the state, local and foreign tax consequences particular to him of the ownership or disposition of common units and potential changes in applicable laws, including the impact of the recently enacted U.S. tax reform legislation.

No ruling has been requested from the Internal Revenue Service (the “IRS”) regarding our characterization as a partnership for tax purposes. Instead, we will rely on opinions of Latham & Watkins LLP. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our common units, including the prices at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

All statements as to matters of U.S. federal income tax law and legal conclusions with respect thereto, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Latham & Watkins LLP and are based on the accuracy of the representations made by us and our general partner.

Notwithstanding the above, and for the reasons described below, Latham & Watkins LLP has not rendered an opinion with respect to the following specific federal income tax issues: (i) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read “-Tax Consequences of Unit Ownership-Treatment of Short Sales”); (ii) whether all aspects of our monthly method for allocating taxable income and losses is permitted by existing Treasury Regulations (please read “-Disposition of Common Units-Allocations Between Transferors and Transferees”); and (iii) 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 Units”).

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable to the partnership or the partner unless the amount of cash distributed to him is in excess of the partner's adjusted basis in his partnership interest. Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the “Qualifying Income Exception,” exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of “qualifying income.” Qualifying income includes income and gains derived from the transportation and processing of certain minerals and natural resources, including crude oil, natural gas and other products of a type that are produced in a petroleum refinery or natural gas processing plant, the retail and wholesale marketing of propane, the transportation of propane and natural gas liquids, certain related hedging activities, certain activities that are intrinsic to other qualifying activities, and our allocable share of our subsidiaries’ income from these sources. Other types of qualifying income include interest (other than from a financial business), dividends, real property rents, gains from the sale of real property and gains from the sale or other disposition of capital assets 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. Based upon and subject to this estimate, the factual representations made by us and our general partner and a review of the applicable legal authorities, Latham & Watkins LLP is of the opinion that at least 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income may change from time to time.

The IRS has made no determination as to our status or the status of our operating subsidiaries for federal income tax purposes. Instead, we will rely on the opinion of Latham & Watkins LLP on such matters. It is the opinion of Latham & Watkins LLP that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below that:

- we will be classified as a partnership for federal income tax purposes; and

- each of our operating subsidiaries, except as otherwise identified to Latham & Watkins LLP, be disregarded as an entity separate from us or will be treated as a partnership for federal income tax purposes.

In rendering its opinion, Latham & Watkins LLP has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Latham & Watkins LLP has relied include:

- neither we nor any of our partnership or limited liability company subsidiaries, other than those identified as such to Latham & Watkins LLP, have elected or will elect to be treated as a corporation for federal income tax purposes; and

- for each taxable year, more than 90% of our gross income has been and will be income of the type that Latham & Watkins LLP has opined or will opine is “qualifying income” within the meaning of Section 7704(d) of the Internal Revenue Code.

We believe that these representations have been true in the past, are true as of the date hereof and expect that these representations will continue to 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 if we had transferred all of our assets, subject to 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 distributed that stock to the unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were treated as an association taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as taxable dividend income, to the extent of our current and accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Latham & Watkins LLP's opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders of Energy Transfer Equity, L.P. will be treated as partners of Energy Transfer Equity, L.P. for federal income tax purposes. Also, 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 Energy Transfer Equity, L.P. for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read "-Tax Consequences of Unit Ownership-Treatment of Short Sales."

Income, gains, losses or deductions would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their tax advisors with respect to the tax consequences to them of holding common units in Energy Transfer Equity, L.P. The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Energy Transfer Equity, L.P. for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

Subject to the discussion below under "-Entity-Level Collections," we will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether we make cash distributions to him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions

Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under "-Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution by us of cash to that unitholder. To the extent our distributions cause a unitholder's "at-risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "-Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. This deemed distribution may constitute a non-pro rata distribution. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation, recapture and/or substantially appreciated "inventory items," each as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, the unitholder will be treated as having been distributed his proportionate share of the Section 751 Assets and then having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (i) the non-pro rata portion of that distribution over (ii) the unitholder's tax basis (often zero) for the share of Section 751 Assets deemed relinquished in the exchange.

Basis of Common Units

A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income, by any increases in his share of our nonrecourse liabilities and, on the disposition of a common unit, by his share of certain items related to business interest not yet deductible by him due to applicable limitations. Please read "-Limitations on Interest Deductions." That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities, by his share of our excess business interest (generally, the excess of our business interest over the amount that is deductible) and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner to the extent of the general partner's "net value" as defined in the Treasury Regulations promulgated under Section 752 of the Internal Revenue Code, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read “-Disposition of Common Units-Recognition of Gain or Loss.”

Limitations on Deductibility of Losses

The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder, estate, trust, or corporate unitholder (if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by or for five or fewer individuals or some tax-exempt organizations), to the amount for which the unitholder is considered to be “at risk” with respect to our activities, if that is less than his tax basis. A common unitholder subject to these limitations must recapture losses deducted in previous years to the extent that distributions cause his 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 these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such common unitholder's tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain would no longer be utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by (i) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (ii) any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at-risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

In addition to the basis and at-risk limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or a unitholder's investments in other publicly traded partnerships, or the unitholder's salary, active business or other income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive loss limitations are applied after other applicable limitations on deductions, including the at-risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

An additional loss limitation may apply to certain of our unitholders for taxable years beginning after December 31, 2017, and before January 1, 2026. A non-corporate unitholder will not be allowed to take a deduction for certain excess business losses in such taxable years. 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. Any losses disallowed in a taxable year due to the excess business loss limitation may be used by the applicable unitholder in the following taxable year if certain conditions are met. Unitholders to which this excess business loss limitation applies will take their allocable share of our items of income, gain, loss and deduction into account in determining this limitation. This excess business loss limitation will be applied to a non-corporate unitholder after the passive loss limitations and may limit such unitholders’ ability to utilize any losses we generate allocable to such unitholder that are not otherwise limited by the basis, at-risk and passive loss limitations described above.

Limitations on Interest Deductions

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business, "business interest," may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

In addition, 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 properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to 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, but generally does not include gains attributable to the disposition of property held for investment or (if applicable) qualified dividend income. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the unitholder on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized 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 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 an individual unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

After giving effect to special allocation provisions with respect to our Convertible Units, if we have a net profit, our items of income, gain, loss and deduction will be allocated among our general partner and the common unitholders in accordance with their percentage interests in us. If we have a net loss, that loss will be allocated to all common unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts, as adjusted for certain items in accordance with applicable Treasury Regulations, and to our general partner in accordance with its percentage interest in us.

Specified items of our income, gain, loss and deduction will be allocated to account for any difference between the tax basis and fair market value of any property contributed to us that exists at the time of such contribution, referred to in this discussion as the "Contributed Property." The effect of these allocations, referred to as Section 704(c) Allocations, to a unitholder purchasing common units from us in an offering will be essentially the same as if the tax bases of our assets were equal to their fair market values at the time of the offering. In the event we issue additional common units or engage in certain other transactions in the future, "reverse Section 704(c) Allocations," similar to the Section 704(c) Allocations described above, will be made to the general partner and all of our common unitholders immediately prior to such issuance or other transactions to account for the difference between the "book" basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of such issuance or future transaction. However, it may not be administratively feasible to make the relevant adjustments to "book" basis and the relevant reverse Section 704(c) Allocations each time we issue common units, particularly in the case of small or frequent common 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 common units. Latham & Watkins LLP is unable to opine as to the validity of such conventions. In addition, items of recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts (subject to certain adjustments), if negative capital accounts (subject to certain adjustments) nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate such negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity," will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has "substantial economic effect." In any other case, a partner's share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Latham & Watkins LLP 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 under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- while not entirely free from doubt, all of these distributions would appear to be ordinary income.

Because there is no direct or indirect controlling authority on the issue relating to partnership interests, Latham & Watkins LLP has not rendered an opinion regarding the tax treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read "-Disposition of Common Units-Recognition of Gain or Loss."

Tax Rates

Currently, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 37% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than twelve months) of individuals is 20%. Such rates are subject to change by new legislation at any time.

In addition, a 3.8% Medicare tax (NIIT) is imposed on 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 units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income 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 (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 such taxable year. The U.S. Department of the Treasury and the IRS have issued Treasury Regulations that provide guidance regarding the NIIT. Prospective common unitholders are urged to consult with their tax advisors as to the impact of the NIIT on an investment in our common units.

For taxable years beginning after December 31, 2017, and ending on or before December 31, 2025, a non-corporate unitholder is entitled to a deduction equal to 20% of its “qualified business income” attributable to us, subject to certain limitations. For purposes of this deduction, a unitholder’s “qualified business income” attributable to us is equal to the sum of:

- the net amount of such unitholder’s allocable share of certain of our items of income, gain, deduction and loss (generally excluding certain items related to our investment activities, including capital gains and dividends, which are subject to a federal income tax rate of 20%); and

- any gain recognized by such unitholder on the disposition of its units to the extent such gain is attributable to certain Section 751 assets, including depreciation recapture and “inventory items” we own.

Prospective unitholders should consult their tax advisors regarding the application of this deduction and its interaction with the overall deduction for qualified business income.

Section 754 Election

We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election generally permits us to adjust a common unit purchaser's tax basis in our assets (“inside basis”) under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply with respect to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, the inside basis in our assets with respect to a unitholder will be considered to have two components: (i) his share of our tax basis in our assets (“common basis”) and (ii) his Section 743(b) adjustment to that basis.

We have adopted the remedial allocation method as to all our properties. Where the remedial allocation method is adopted, the Treasury Regulations under Section 743 of the Internal Revenue Code require a portion of the Section 743(b) adjustment that is attributable to recovery property that is subject to depreciation under Section 168 of the Internal Revenue Code and whose book basis is in excess of its tax basis to be depreciated over the remaining cost recovery period for the property's unamortized Book-Tax Disparity. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, our general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these and any other Treasury Regulations. Please read “-Uniformity of Units.”

We depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as non-amortizable to the extent attributable to property that is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read “-Uniformity of Units.” A unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate such unitholder's basis in his common units, which may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read “-Disposition of Common Units-Recognition of Gain or Loss.” Latham & Watkins LLP is unable to opine as to whether our method for taking into account Section 743 adjustments is sustainable for property subject to depreciation under Section 167 of the Internal Revenue Code or if we use an aggregate approach as described above, as there is no direct or indirect controlling authority addressing the validity of these positions. Moreover, the IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the units. If such a challenge were sustained, the gain from the sale of units might be increased without the benefit of additional deductions.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer. Generally, a built-in loss is substantial if (i) it exceeds $250,000 or (ii) the transferee would be allocated a net loss in excess of $250,000 on a hypothetical sale of our assets for their fair market value immediately after a transfer of the interest at issue. In addition, a basis adjustment is required regardless of whether a Section 754 election is made if we distribute property and have a substantial basis reduction. A substantial basis reduction exists if, on a liquidating distribution of property to a unitholder, there would be a negative basis adjustment to our assets in excess of $250,000 if a Section 754 election were in place.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different 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 units may be allocated more income than he 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 income his share of our income, gain, loss and deduction for our taxable year ending within or with his 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 his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his 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 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. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to an offering will be borne by our unitholders holding interests in us prior to any such offering. Please read “-Tax Consequences of Unit Ownership-Allocation of Income, Gain, Loss and Deduction.”

To the extent allowable, we may use the depreciation and cost recovery methods, including bonus depreciation to the extent available, that will result in the largest deductions being taken in the early years after assets subject to these allowances are placed in service. Please read “-Uniformity of Units.” Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

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 previously deducted and the nature of the property, 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 his 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 selling our units (called “syndication expenses”) must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of 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.

Valuation and Tax Basis of Our Properties

The U.S. federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, 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 basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or determinations of basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us that in the aggregate were in excess of cumulative net taxable income for a common unit and, therefore, decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a “dealer” in units, on the sale or exchange of a unit will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held for more than twelve months will generally be taxed at the U.S. federal income tax rate applicable to long-term capital gains. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to “unrealized receivables,” including potential recapture items such as depreciation recapture, or to “inventory items” we own. Ordinary income attributable to unrealized receivables and inventory items may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations. Ordinary income recognized by a unitholder on disposition of our units may be reduced by such unitholder’s deduction for qualified business income. Both ordinary income and capital gain recognized on a sale of units may be subject to the NIIT in certain circumstances. Please read “-Tax Consequences of Unit Ownership-Tax Rates.”

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 his 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 Internal Revenue 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 above, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, he may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an “appreciated” partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract;

in each case, 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 also authorized to issue 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.

Allocations Between Transferors and Transferees

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis in proportion to the number of days in each month and will be subsequently apportioned among our unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among our unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The U.S. Department of Treasury and the IRS have issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. Accordingly, Latham & Watkins LLP is unable to opine on the validity of this method of allocating income and deductions between transferor and transferee unitholders. If this method is not allowed under the Treasury Regulations, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferor and transferee unitholders, as well as unitholders whose interests vary during a taxable year.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter through the month of disposition but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase 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 Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read "-Tax Consequences of Unit Ownership-Section 754 Election." We depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code, even though that position may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read "-Tax Consequences of Unit Ownership-Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. In either case, and as stated above under "-Tax Consequences of Unit Ownership-Section 754 Election," Latham & Watkins LLP has not rendered an opinion with respect to these methods. Moreover, the IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read "-Disposition of Common Units-Recognition of Gain or Loss." In addition, as described above under "-Tax Consequences of Unit Ownership-Allocation of Income, Gain, Loss and Deduction," if we aggregate multiple issuances of common units for purposes of making adjustments to "book" basis and the related tax allocations, we will treat each of our common units as having the same capital account balance, regardless of the price actually paid by each purchaser of common units in the aggregated offerings. Latham & Watkins LLP is unable to opine as to the validity of such an approach. We do not expect the number of affected common units, or the differences between the purchase price of a common unit and the initial capital account balance assigned to the common unit, to be material, and we do not expect this convention will have a material effect upon the trading of our common units.

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below to a limited extent, may have substantially adverse tax consequences to them. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units. Employee benefit plans and most other organizations exempt from federal income tax, including IRAs and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay U.S. federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, our quarterly distribution to foreign unitholders will be subject to withholding at the highest applicable effective tax rate. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN, W-8BEN-E or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a U.S. trade or business, that corporation 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 earnings and profits, as adjusted for changes in the foreign corporation's "U.S. net equity," that is effectively connected with the conduct of a U.S. trade or business. 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 Internal Revenue Code.

A foreign unitholder who sells or otherwise disposes of a common 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 foreign unitholder. Gain on the sale or disposition of a common unit will be treated as effectively connected with a U.S. trade or business to the extent that a foreign unitholder would recognize gain effectively connected with a U.S. trade or business upon the hypothetical sale of our assets at fair market value on the date of the sale or exchange of that unit. Such gain shall be reduced by certain amounts treated as effectively connected with a U.S. trade or business attributable to certain real property interests, as set forth in the following paragraph.

Under the Foreign Investment in Real Property Tax Act, a foreign common unitholder (other than certain "qualified foreign pension funds" (or an entity all of the interests of which are held by such a qualified foreign pension fund), which generally are entities or arrangements that are established and regulated by foreign law to provide retirement or other pension benefits to employees, do not have a single participant or beneficiary that is entitled to more than 5% of the assets or income of the entity or arrangement and are subject to certain preferential tax treatment under the laws of the applicable foreign country) generally will be subject to U.S. federal income tax upon the sale or disposition of a common unit if (i) he owned (directly or constructively applying certain attribution rules) more than 5% of our common units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such unitholder held the common units or the five-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests and we do not expect that to change in the foreseeable future.

Therefore, foreign unitholders may be subject to U.S. federal income tax on gain from the sale or disposition of their units.

Upon the sale, exchange or other disposition of a common unit by a foreign unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. If the transferee fails to satisfy this withholding requirement, we will be required to deduct and withhold such amount (plus interest) from future distributions to the transferee. Because the "amount realized" would include a unitholder's share of our nonrecourse liabilities, 10% of the amount realized could exceed the total cash purchase price for such disposed units. Due to this fact, our inability to match transferors and transferees of common units, and other uncertainty surrounding the application of these withholding rules, the U.S. Department of the Treasury and the IRS have currently suspended these rules for transfers of certain publicly traded partnership interests, including transfers of our common units, until regulations or other guidance has been issued. It is unclear when such regulations or other guidance will be issued.

Additional withholding requirements may also affect certain foreign unitholders. Please read "-Administrative Matters-Additional Withholding Requirements."

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his 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 you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Latham & Watkins LLP can assure prospective common unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal 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 with the partners. For taxable years beginning on or before December 31, 2017, the Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. Our partnership agreement names our general partner as our Tax Matters Partner.

The Tax Matters Partner has made and will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

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. 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 and its 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, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our common unitholders might be substantially reduced.

Additionally, pursuant to the Bipartisan Budget Act of 2015, the Internal Revenue 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, U.S. 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 our Partnership Representative. Further, any actions taken by us or by the Partnership Representative on our behalf with respect to, among other things, U.S. 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 Internal Revenue Code) and certain other foreign entities. Specifically, a 30% withholding tax may be imposed on interest, dividends and other fixed or determinable annual or periodical 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 that 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 Internal Revenue 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 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.

These rules generally apply to payments of FDAP Income currently and generally will apply to payments of relevant Gross Proceeds made on or after January 1, 2019. Thus, to the extent we have FDAP Income or 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"), unitholders who are foreign financial institutions or certain other foreign entities, or persons that hold their common units through such foreign entities, may be subject to withholding on distributions they receive from us, or their distributive share of our income, pursuant to the rules described above.

Prospective common unitholders should consult their own tax advisors regarding the potential application of these withholding provisions to their 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;
- whether the beneficial owner is:
  - a person that is not a U.S. person;
  - a foreign 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 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 dispositions.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $260 per failure, up to a maximum of $3,218,500 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties

Certain penalties may be imposed on taxpayers as a result of an underpayment of tax that is attributable to one or more specified causes, including: (i) negligence or disregard of rules or regulations, (ii) substantial understatements of income tax, (iii) substantial valuation misstatements and (iv) the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law. Except with respect to the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law, however, no penalty will be imposed for any portion of any such 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.

With respect to substantial understatements of income tax, the amount of any understatement subject to penalty generally is reduced by that portion of the understatement which is attributable to a position adopted on the return: (A) for which there is, or was, “substantial authority”; or (B) as to which there is a reasonable basis and the relevant facts of that position are adequately disclosed on the return. If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an “understatement” of income for which no “substantial authority” exists, we must adequately disclose the relevant facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty.

Recent Legislative Developments

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of Congress and the President propose and consider substantive changes to the existing federal income tax laws that affect the tax treatment of publicly traded partnerships and our common unitholders.

Recently, the President signed into law comprehensive U.S. federal tax reform legislation that significantly reforms the Internal Revenue Code. This legislation, among other things, contains significant changes to the taxation of our operations and an investment in our common units, including a partial limitation on the deductibility of certain business interest expenses, a deduction for our unitholders relating to certain income from partnerships, immediate deductions for certain new investments instead of deductions for depreciation over time and the modification or repeal of many business deductions and credits. We continue to examine the impact of this tax reform legislation, and as its overall impact is uncertain, we note that this tax reform legislation could adversely affect the value of an investment in our common units. Prospective common unitholders are urged to consult their tax advisors regarding the impact of this tax reform legislation on an investment in our common units.

Additional modifications to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for federal income tax purposes. Please read “-Partnership Status.” We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you will likely be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective common unitholder should consider their potential impact on his investment in us. We currently own property or do business in many states. Several of these states impose a personal income tax on individuals; certain of these states also impose an income tax on corporations and other entities. We may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. 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. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read “-Tax Consequences of Unit Ownership-Entity-Level Collections.” Based on current law and our estimate of our future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states, localities and foreign jurisdictions, of his investment in us. Accordingly, each prospective common unitholder is urged to consult his 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 foreign, as well as U.S. federal tax returns, that may be required of him. Latham & Watkins LLP has not rendered an opinion on the state tax, local tax, alternative minimum tax or foreign tax consequences of an investment in us.

Exhibit 99.2

Material U.S. Federal Income Tax Consequences

The tax consequences to you of an investment in our common units will depend in part on your own tax circumstances. This section should be read in conjunction with the risk factors included under the caption “Tax Risks to Unitholders” in our most recent Annual Report on Form 10-K. This section is a summary of the material U.S. federal income tax consequences that may be relevant to prospective common unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Latham & Watkins LLP, counsel to our general partner and us, insofar as it relates to legal conclusions with respect to matters of U.S. federal income tax law. This section is based upon current provisions of the Internal Revenue Code of 1986, as amended (the “Internal Revenue Code”), existing and proposed Treasury regulations promulgated under the Internal Revenue Code (the “Treasury Regulations”) and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to “us” or “we” are references to Energy Transfer Equity, L.P. and our operating subsidiaries.

The following discussion does not comment on all federal income tax matters affecting us or our unitholders and does not describe the application of the alternative minimum tax that may be applicable to certain unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, entities treated as partnerships for U.S. federal income tax purposes, trusts, nonresident aliens, U.S. expatriates and former citizens or long-term residents of the United States or other unitholders subject to specialized tax treatment, such as banks, insurance companies and other financial institutions, tax-exempt institutions, foreign persons (including, without limitation, controlled foreign corporations, passive foreign investment companies and foreign persons eligible for the benefits of an applicable income tax treaty with the United States), individual retirement accounts (IRAs), real estate investment trusts (REITs) or mutual funds, dealers in securities or currencies, traders in securities, U.S. persons whose “functional currency” is not the U.S. dollar, persons holding their units as part of a “straddle,” “hedge,” “conversion transaction” or other risk reduction transaction, persons subject to special tax accounting rules as a result of any item of gross income with respect to our common units being taken into account in an applicable financial statement and persons deemed to sell their units under the constructive sale provisions of the Internal Revenue Code. In addition, the discussion only comments, to a limited extent, on state, local, and foreign tax consequences. Accordingly, we encourage each prospective common unitholder to consult his own tax advisor in analyzing the state, local and foreign tax consequences particular to him of the ownership or disposition of common units and potential changes in applicable laws, including the impact of the recently enacted U.S. tax reform legislation.

No ruling has been requested from the Internal Revenue Service (the “IRS”) regarding our characterization as a partnership for tax purposes. Instead, we will rely on opinions of Latham & Watkins LLP. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our common units, including the prices at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

All statements as to matters of U.S. federal income tax law and legal conclusions with respect thereto, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Latham & Watkins LLP and are based on the accuracy of the representations made by us and our general partner.

Notwithstanding the above, and for the reasons described below, Latham & Watkins LLP has not rendered an opinion with respect to the following specific federal income tax issues: (i) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read “-Tax Consequences of Unit Ownership-Treatment of Short Sales”); (ii) whether all aspects of our monthly method for allocating taxable income and losses is permitted by existing Treasury Regulations (please read “-Disposition of Common Units-Allocations Between Transferors and Transferees”); and (iii) 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 Units”).

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable to the partnership or the partner unless the amount of cash distributed to him is in excess of the partner's adjusted basis in his partnership interest. Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the “Qualifying Income Exception,” exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of “qualifying income.” Qualifying income includes income and gains derived from the transportation and processing of certain minerals and natural resources, including crude oil, natural gas and other products of a type that are produced in a petroleum refinery or natural gas processing plant, the retail and wholesale marketing of propane, the transportation of propane and natural gas liquids, certain related hedging activities, certain activities that are intrinsic to other qualifying activities, and our allocable share of our subsidiaries’ income from these sources. Other types of qualifying income include interest (other than from a financial business), dividends, real property rents, gains from the sale of real property and gains from the sale or other disposition of capital assets 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. Based upon and subject to this estimate, the factual representations made by us and our general partner and a review of the applicable legal authorities, Latham & Watkins LLP is of the opinion that at least 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income may change from time to time.

The IRS has made no determination as to our status or the status of our operating subsidiaries for federal income tax purposes. Instead, we will rely on the opinion of Latham & Watkins LLP on such matters. It is the opinion of Latham & Watkins LLP that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below that:

- we will be classified as a partnership for federal income tax purposes; and
- each of our operating subsidiaries, except as otherwise identified to Latham & Watkins LLP, be disregarded as an entity separate from us or will be treated as a partnership for federal income tax purposes.

In rendering its opinion, Latham & Watkins LLP has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Latham & Watkins LLP has relied include:

- neither we nor any of our partnership or limited liability company subsidiaries, other than those identified as such to Latham & Watkins LLP, have elected or will elect to be treated as a corporation for federal income tax purposes; and
- for each taxable year, more than 90% of our gross income has been and will be income of the type that Latham & Watkins LLP has opined or will opine is “qualifying income” within the meaning of Section 7704(d) of the Internal Revenue Code.

We believe that these representations have been true in the past, are true as of the date hereof and expect that these representations will continue to 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 if we had transferred all of our assets, subject to 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 distributed that stock to the unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were treated as an association taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as taxable dividend income, to the extent of our current and accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Latham & Watkins LLP's opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders of Energy Transfer Equity, L.P. will be treated as partners of Energy Transfer Equity, L.P. for federal income tax purposes. Also, 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 Energy Transfer Equity, L.P. for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read "-Tax Consequences of Unit Ownership-Treatment of Short Sales."

Income, gains, losses or deductions would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their tax advisors with respect to the tax consequences to them of holding common units in Energy Transfer Equity, L.P. The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Energy Transfer Equity, L.P. for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

Subject to the discussion below under "-Entity-Level Collections," we will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether we make cash distributions to him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions

Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under "-Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution by us of cash to that unitholder. To the extent our distributions cause a unitholder's "at-risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "-Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. This deemed distribution may constitute a non-pro rata distribution. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation, recapture and/or substantially appreciated "inventory items," each as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, the unitholder will be treated as having been distributed his proportionate share of the Section 751 Assets and then having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (i) the non-pro rata portion of that distribution over (ii) the unitholder's tax basis (often zero) for the share of Section 751 Assets deemed relinquished in the exchange.

Basis of Common Units

A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income, by any increases in his share of our nonrecourse liabilities and, on the disposition of a common unit, by his share of certain items related to business interest not yet deductible by him due to applicable limitations. Please read "-Limitations on Interest Deductions." That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities, by his share of our excess business interest (generally, the excess of our business interest over the amount that is deductible) and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner to the extent of the general partner's "net value" as defined in the Treasury Regulations promulgated under Section 752 of the Internal Revenue Code, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read “-Disposition of Common Units-Recognition of Gain or Loss.”

Limitations on Deductibility of Losses

The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder, estate, trust, or corporate unitholder (if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by or for five or fewer individuals or some tax-exempt organizations), to the amount for which the unitholder is considered to be “at risk” with respect to our activities, if that is less than his tax basis. A common unitholder subject to these limitations must recapture losses deducted in previous years to the extent that distributions cause his 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 these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such common unitholder's tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain would no longer be utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by (i) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (ii) any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at-risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

In addition to the basis and at-risk limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or a unitholder's investments in other publicly traded partnerships, or the unitholder's salary, active business or other income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive loss limitations are applied after other applicable limitations on deductions, including the at-risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

An additional loss limitation may apply to certain of our unitholders for taxable years beginning after December 31, 2017, and before January 1, 2026. A non-corporate unitholder will not be allowed to take a deduction for certain excess business losses in such taxable years. 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. Any losses disallowed in a taxable year due to the excess business loss limitation may be used by the applicable unitholder in the following taxable year if certain conditions are met. Unitholders to which this excess business loss limitation applies will take their allocable share of our items of income, gain, loss and deduction into account in determining this limitation. This excess business loss limitation will be applied to a non-corporate unitholder after the passive loss limitations and may limit such unitholders’ ability to utilize any losses we generate allocable to such unitholder that are not otherwise limited by the basis, at-risk and passive loss limitations described above.

Limitations on Interest Deductions

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business, “business interest,” may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

In addition, 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 properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to 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, but generally does not include gains attributable to the disposition of property held for investment or (if applicable) qualified dividend income. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the unitholder on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized 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 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 an individual unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

After giving effect to special allocation provisions with respect to our Convertible Units, if we have a net profit, our items of income, gain, loss and deduction will be allocated among our general partner and the common unitholders in accordance with their percentage interests in us. If we have a net loss, that loss will be allocated to all common unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts, as adjusted for certain items in accordance with applicable Treasury Regulations, and to our general partner in accordance with its percentage interest in us.

Specified items of our income, gain, loss and deduction will be allocated to account for any difference between the tax basis and fair market value of any property contributed to us that exists at the time of such contribution, referred to in this discussion as the “Contributed Property.” The effect of these allocations, referred to as Section 704(c) Allocations, to a unitholder purchasing common units from us in an offering will be essentially the same as if the tax bases of our assets were equal to their fair market values at the time of the offering. In the event we issue additional common units or engage in certain other transactions in the future, “reverse Section 704(c) Allocations,” similar to the Section 704(c) Allocations described above, will be made to the general partner and all of our common unitholders immediately prior to such issuance or other transactions to account for the difference between the “book” basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of such issuance or future transaction. In addition, items of recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts (subject to certain adjustments), if negative capital accounts (subject to certain adjustments) nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate such negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity," will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has "substantial economic effect." In any other case, a partner's share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Latham & Watkins LLP 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 under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- while not entirely free from doubt, all of these distributions would appear to be ordinary income.

Because there is no direct or indirect controlling authority on the issue relating to partnership interests, Latham & Watkins LLP has not rendered an opinion regarding the tax treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read "-Disposition of Common Units-Recognition of Gain or Loss."

Tax Rates

Currently, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 37% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than twelve months) of individuals is 20%. Such rates are subject to change by new legislation at any time.

In addition, a 3.8% Medicare tax (NIIT) is imposed on 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 units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income 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 (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 such taxable year. The U.S. Department of the Treasury and the IRS have issued Treasury Regulations that provide guidance regarding the NIIT. Prospective common unitholders are urged to consult with their tax advisors as to the impact of the NIIT on an investment in our common units.

For taxable years beginning after December 31, 2017, and ending on or before December 31, 2025, a non-corporate unitholder is entitled to a deduction equal to 20% of its “qualified business income” attributable to us, subject to certain limitations. For purposes of this deduction, a unitholder’s “qualified business income” attributable to us is equal to the sum of:

- the net amount of such unitholder’s allocable share of certain of our items of income, gain, deduction and loss (generally excluding certain items related to our investment activities, including capital gains and dividends, which are subject to a federal income tax rate of 20%); and

- any gain recognized by such unitholder on the disposition of its units to the extent such gain is attributable to certain Section 751 assets, including depreciation recapture and “inventory items” we own.

Prospective unitholders should consult their tax advisors regarding the application of this deduction and its interaction with the overall deduction for qualified business income.

Section 754 Election

We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election generally permits us to adjust a common unit purchaser's tax basis in our assets (“inside basis”) under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply with respect to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, the inside basis in our assets with respect to a unitholder will be considered to have two components: (i) his share of our tax basis in our assets (“common basis”) and (ii) his Section 743(b) adjustment to that basis.

We have adopted the remedial allocation method as to all our properties. Where the remedial allocation method is adopted, the Treasury Regulations under Section 743 of the Internal Revenue Code require a portion of the Section 743(b) adjustment that is attributable to recovery property that is subject to depreciation under Section 168 of the Internal Revenue Code and whose book basis is in excess of its tax basis to be depreciated over the remaining cost recovery period for the property's unamortized Book-Tax Disparity. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, our general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these and any other Treasury Regulations. Please read “-Uniformity of Units.”

We depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as non-amortizable to the extent attributable to property that is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read “-Uniformity of Units.” A unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate such unitholder's basis in his common units, which may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read “-Disposition of Common Units-Recognition of Gain or Loss.” Latham & Watkins LLP is unable to opine as to whether our method for taking into account Section 743 adjustments is sustainable for property subject to depreciation under Section 167 of the Internal Revenue Code or if we use an aggregate approach as described above, as there is no direct or indirect controlling authority addressing the validity of these positions. Moreover, the IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the units. If such a challenge were sustained, the gain from the sale of units might be increased without the benefit of additional deductions.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer. Generally, a built-in loss is substantial if (i) it exceeds $250,000 or (ii) the transferee would be allocated a net loss in excess of $250,000 on a hypothetical sale of our assets for their fair market value immediately after a transfer of the interest at issue. In addition, a basis adjustment is required regardless of whether a Section 754 election is made if we distribute property and have a substantial basis reduction. A substantial basis reduction exists if, on a liquidating distribution of property to a unitholder, there would be a negative basis adjustment to our assets in excess of $250,000 if a Section 754 election were in place.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different 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 units may be allocated more income than he 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 income his share of our income, gain, loss and deduction for our taxable year ending within or with his 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 his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his 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 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. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to an offering will be borne by our unitholders holding interests in us prior to any such offering. Please read "-Tax Consequences of Unit Ownership-Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may use the depreciation and cost recovery methods, including bonus depreciation to the extent available, that will result in the largest deductions being taken in the early years after assets subject to these allowances are placed in service. Please read "-Uniformity of Units." Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

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 previously deducted and the nature of the property, 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 his 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 selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of 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.

Valuation and Tax Basis of Our Properties

The U.S. federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, 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 basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or determinations of basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us that in the aggregate were in excess of cumulative net taxable income for a common unit and, therefore, decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a “dealer” in units, on the sale or exchange of a unit will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held for more than twelve months will generally be taxed at the U.S. federal income tax rate applicable to long-term capital gains. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to “unrealized receivables,” including potential recapture items such as depreciation recapture, or to “inventory items” we own. Ordinary income attributable to unrealized receivables and inventory items may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations. Ordinary income recognized by a unitholder on disposition of our units may be reduced by such unitholder’s deduction for qualified business income. Both ordinary income and capital gain recognized on a sale of units may be subject to the NIIT in certain circumstances. Please read “-Tax Consequences of Unit Ownership-Tax Rates.”

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 his 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 Internal Revenue 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 above, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, he may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an “appreciated” partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract;

in each case, 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 also authorized to issue 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.

Allocations Between Transferors and Transferees

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis in proportion to the number of days in each month and will be subsequently apportioned among our unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the “Allocation Date.” However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among our unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The U.S. Department of Treasury and the IRS have issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. Accordingly, Latham & Watkins LLP is unable to opine on the validity of this method of allocating income and deductions between transferor and transferee unitholders. If this method is not allowed under the Treasury Regulations, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferor and transferee unitholders, as well as unitholders whose interests vary during a taxable year.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter through the month of disposition but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase 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 Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read “-Tax Consequences of Unit Ownership-Section 754 Election.” We depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code, even though that position may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read “-Tax Consequences of Unit Ownership-Section 754 Election.” To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. In either case, and as stated above under “-Tax Consequences of Unit Ownership-Section 754 Election,” Latham & Watkins LLP has not rendered an opinion with respect to these methods. Moreover, the IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read "-Disposition of Common Units-Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below to a limited extent, may have substantially adverse tax consequences to them. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units. Employee benefit plans and most other organizations exempt from federal income tax, including IRAs and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay U.S. federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, our quarterly distribution to foreign unitholders will be subject to withholding at the highest applicable effective tax rate. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN, W-8BEN-E or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a U.S. trade or business, that corporation 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 earnings and profits, as adjusted for changes in the foreign corporation's "U.S. net equity," that is effectively connected with the conduct of a U.S. trade or business. 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 Internal Revenue Code.

A foreign unitholder who sells or otherwise disposes of a common 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 foreign unitholder. Gain on the sale or disposition of a common unit will be treated as effectively connected with a U.S. trade or business to the extent that a foreign unitholder would recognize gain effectively connected with a U.S. trade or business upon the hypothetical sale of our assets at fair market value on the date of the sale or exchange of that unit. Such gain shall be reduced by certain amounts treated as effectively connected with a U.S. trade or business attributable to certain real property interests, as set forth in the following paragraph.

Under the Foreign Investment in Real Property Tax Act, a foreign common unitholder (other than certain "qualified foreign pension funds" (or an entity all of the interests of which are held by such a qualified foreign pension fund), which generally are entities or arrangements that are established and regulated by foreign law to provide retirement or other pension benefits to employees, do not have a single participant or beneficiary that is entitled to more than 5% of the assets or income of the entity or arrangement and are subject to certain preferential tax treatment under the laws of the applicable foreign country) generally will be subject to U.S. federal income tax upon the sale or disposition of a common unit if (i) he owned (directly or constructively applying certain attribution rules) more than 5% of our common units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such unitholder held the common units or the five-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests and we do not expect that to change in the foreseeable future.

Therefore, foreign unitholders may be subject to U.S. federal income tax on gain from the sale or disposition of their units.

Upon the sale, exchange or other disposition of a common unit by a foreign unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. If the transferee fails to satisfy this withholding requirement, we will be required to deduct and withhold such amount (plus interest) from future distributions to the transferee. Because the "amount realized" would include a unitholder's share of our nonrecourse liabilities, 10% of the amount realized could exceed the total cash purchase price for such disposed units. Due to this fact, our inability to match transferors and transferees of common units, and other uncertainty surrounding the application of these withholding rules, the U.S. Department of the Treasury and the IRS have currently suspended these rules for transfers of certain publicly traded partnership interests, including transfers of our common units, until regulations or other guidance has been issued. It is unclear when such regulations or other guidance will be issued.

Additional withholding requirements may also affect certain foreign unitholders. Please read “-Administrative Matters-Additional Withholding Requirements.”

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his 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 you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Latham & Watkins LLP can assure prospective common unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal 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 with the partners. For taxable years beginning on or before December 31, 2017, the Internal Revenue Code requires that one partner be designated as the “Tax Matters Partner” for these purposes. Our partnership agreement names our general partner as our Tax Matters Partner.

The Tax Matters Partner has made and will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

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. 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 and its 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, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our common unitholders might be substantially reduced.

Additionally, pursuant to the Bipartisan Budget Act of 2015, the Internal Revenue 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, U.S. 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 our Partnership Representative. Further, any actions taken by us or by the Partnership Representative on our behalf with respect to, among other things, U.S. 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 Internal Revenue Code) and certain other foreign entities. Specifically, a 30% withholding tax may be imposed on interest, dividends and other fixed or determinable annual or periodical 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 that 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 Internal Revenue 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 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.

These rules generally apply to payments of FDAP Income currently and generally will apply to payments of relevant Gross Proceeds made on or after January 1, 2019. Thus, to the extent we have FDAP Income or 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"), unitholders who are foreign financial institutions or certain other foreign entities, or persons that hold their common units through such foreign entities, may be subject to withholding on distributions they receive from us, or their distributive share of our income, pursuant to the rules described above.

Prospective common unitholders should consult their own tax advisors regarding the potential application of these withholding provisions to their 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;
- whether the beneficial owner is:
    - a person that is not a U.S. person;
    - a foreign 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 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 dispositions.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $260 per failure, up to a maximum of $3,218,500 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties

Certain penalties may be imposed on taxpayers as a result of an underpayment of tax that is attributable to one or more specified causes, including: (i) negligence or disregard of rules or regulations, (ii) substantial understatements of income tax, (iii) substantial valuation misstatements and (iv) the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law. Except with respect to the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law, however, no penalty will be imposed for any portion of any such 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.

With respect to substantial understatements of income tax, the amount of any understatement subject to penalty generally is reduced by that portion of the understatement which is attributable to a position adopted on the return: (A) for which there is, or was, “substantial authority”; or (B) as to which there is a reasonable basis and the relevant facts of that position are adequately disclosed on the return. If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an “understatement” of income for which no “substantial authority” exists, we must adequately disclose the relevant facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty.

Recent Legislative Developments

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of Congress and the President propose and consider substantive changes to the existing federal income tax laws that affect the tax treatment of publicly traded partnerships and our common unitholders.

Recently, the President signed into law comprehensive U.S. federal tax reform legislation that significantly reforms the Internal Revenue Code. This legislation, among other things, contains significant changes to the taxation of our operations and an investment in our common units, including a partial limitation on the deductibility of certain business interest expenses, a deduction for our unitholders relating to certain income from partnerships, immediate deductions for certain new investments instead of deductions for depreciation over time and the modification or repeal of many business deductions and credits. We continue to examine the impact of this tax reform legislation, and as its overall impact is uncertain, we note that this tax reform legislation could adversely affect the value of an investment in our common units. Prospective common unitholders are urged to consult their tax advisors regarding the impact of this tax reform legislation on an investment in our common units.

Additional modifications to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for federal income tax purposes. Please read “-Partnership Status.” We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you will likely be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective common unitholder should consider their potential impact on his investment in us. We currently own property or do business in many states. Several of these states impose a personal income tax on individuals; certain of these states also impose an income tax on corporations and other entities. We may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. 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. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read “-Tax Consequences of Unit Ownership-Entity-Level Collections.” Based on current law and our estimate of our future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states, localities and foreign jurisdictions, of his investment in us. Accordingly, each prospective common unitholder is urged to consult his 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 foreign, as well as U.S. federal tax returns, that may be required of him. Latham & Watkins LLP has not rendered an opinion on the state tax, local tax, alternative minimum tax or foreign tax consequences of an investment in us.