Energy Transfer Partners, L.P.
Form 10-Q
August 09, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended June 30, 2018
or

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

Commission file number 1-31219
ENERGY TRANSFER PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

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

8111 Westchester Drive, Suite 600, Dallas, Texas 75225
(Address of principal executive offices) (zip code)
(214) 981-0700
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý 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 ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	ý	Accelerated filer	¨
Non-accelerated filer	¨ (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 ý
At August 3, 2018, the registrant had 1,166,403,685 Common Units outstanding.

Table of Contents

FORM 10-Q
ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
TABLE OF CONTENTS

Table of Contents

Forward-Looking Statements

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

Definitions

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

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

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

Table of Contents

IDRs	incentive distribution rights
Legacy ETP Preferred Units	legacy ETP Series A cumulative convertible preferred units
LIBOR	London Interbank Offered Rate
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PennTex	PennTex Midstream Partners, LP
PES	Philadelphia Energy Solutions
Regency	Regency Energy Partners LP
Retail Holdings	ETP Retail Holdings, LLC, a wholly-owned subsidiary of Sunoco, Inc.
RIGS	Regency Intrastate Gas LP
Rover	Rover Pipeline LLC, a subsidiary of ETP
SEC	Securities and Exchange Commission
Series A Preferred Units	6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series B Preferred Units	6.625% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series C Preferred Units	7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series D Preferred Units	7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units

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

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

Table of Contents

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

	June 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$494	$ 306
Accounts receivable, net	3,684	3,946
Accounts receivable from related companies	334	318
Inventories	1,256	1,589
Income taxes receivable	172	135
Derivative assets	57	24
Other current assets	550	210
Total current assets	6,547	6,528
Property, plant and equipment	69,637	67,699
Accumulated depreciation and depletion	(9,861)	(9,262)
	59,776	58,437
Advances to and investments in unconsolidated affiliates	3,636	3,816
Other non-current assets, net	762	758
Intangible assets, net	4,988	5,311
Goodwill	2,861	3,115
Total assets	$78,570	$ 77,965

The accompanying notes are an integral part of these consolidated financial statements.
1

Table of Contents

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

	June 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$3,488	$ 4,126
Accounts payable to related companies	329	209
Derivative liabilities	385	109
Accrued and other current liabilities	2,284	2,143
Current maturities of long-term debt	155	407
Total current liabilities	6,641	6,994
Long-term debt, less current maturities	33,741	32,687
Non-current derivative liabilities	135	145
Deferred income taxes	2,917	2,883
Other non-current liabilities	1,079	1,084
Commitments and contingencies		
Redeemable noncontrolling interests	21	21
Equity:		
Limited Partners:		
Series A Preferred Unitholders	958	944
Series B Preferred Unitholders	556	547
Series C Preferred Unitholders	442	—
Common Unitholders	25,546	26,531
General Partner	359	244
Accumulated other comprehensive income	4	3
Total partners' capital	27,865	28,269
Noncontrolling interest	6,171	5,882
Total equity	34,036	34,151
Total liabilities and equity	$78,570	$ 77,965

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

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017*	2018	2017*
REVENUES:				
Natural gas sales	$1,024	$1,022	$2,086	$2,034
NGL sales	2,141	1,485	4,171	3,032
Crude sales	4,241	2,345	7,495	4,887
Gathering, transportation and other fees	1,464	1,067	2,861	2,091
Refined product sales	413	304	852	775
Other	127	353	225	652
Total revenues	9,410	6,576	17,690	13,471
COSTS AND EXPENSES:				
Cost of products sold	7,140	4,624	13,128	9,674
Operating expenses	627	539	1,231	1,031
Depreciation, depletion and amortization	588	557	1,191	1,117
Selling, general and administrative	112	120	224	230
Total costs and expenses	8,467	5,840	15,774	12,052
OPERATING INCOME	943	736	1,916	1,419
OTHER INCOME (EXPENSE):				
Interest expense, net	(358)	(336)	(704)	(668)
Equity in earnings (losses) of unconsolidated affiliates	106	(61)	34	12
Gain on Sunoco LP common unit repurchase	—	—	172	—
Loss on deconsolidation of CDM	(86)	—	(86)	—
Gains (losses) on interest rate derivatives	20	(25)	72	(20)
Other, net	46	61	106	80
INCOME BEFORE INCOME TAX EXPENSE	671	375	1,510	823
Income tax expense	69	79	29	134
NET INCOME	602	296	1,481	689
Less: Net income attributable to noncontrolling interest	170	94	334	156
NET INCOME ATTRIBUTABLE TO PARTNERS	432	202	1,147	533
Series A Preferred Unitholders' interest in net income	15	—	30	—
Series B Preferred Unitholders' interest in net income	9	—	18	—
Series C Preferred Unitholders' interest in net income	6	—	6	—
General Partner's interest in net income	402	251	804	457
Class H Unitholder's interest in net income	—	—	—	93
Common Unitholders' interest in net income (loss)	$—	$(49)	$289	$(17)
NET INCOME (LOSS) PER COMMON UNIT:				
Basic	$(0.01)	$(0.04)	$0.23	$(0.02)
Diluted	$(0.01)	$(0.04)	$0.23	$(0.02)

* As adjusted. See Note 1.

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

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017*	2018	2017*
Net income	$602	$296	$1,481	689
Other comprehensive income (loss), net of tax:				
Change in value of available-for-sale securities	—	1	(2)	3
Actuarial loss relating to pension and other postretirement benefit plans	—	(1)	(2)	(3)
Change in other comprehensive income from unconsolidated affiliates	2	(1)	7	(1)
	2	(1)	3	(1)
Comprehensive income	604	295	1,484	688
Less: Comprehensive income attributable to noncontrolling interest	170	94	334	156
Comprehensive income attributable to partners	$434	$201	$1,150	$532

* As adjusted. See Note 1.

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

Table of Contents

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

	Limited Partners							
	Series A Preferred Units	Series B Preferred Units	Series C Preferred Units	Common Units	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2017	$944	$ 547	$ —	$26,531	$244	$ 3	$ 5,882	$34,151
Distributions to partners	(15)	(9)	—	(1,315)	(672)	—	—	(2,011)
Distributions to noncontrolling interest	—	—	—	—	—	—	(359)	(359)
Units issued for cash	—	—	436	39	—	—	—	475
Capital contributions from noncontrolling interest	—	—	—	—	—	—	318	318
Repurchases of common units	—	—	—	(24)	—	—	—	(24)
Other comprehensive income, net of tax	—	—	—	—	—	3	—	3
Other, net	(1)	—	—	26	(17)	(2)	(4)	2
Net income	30	18	6	289	804	—	334	1,481
Balance, June 30, 2018	$958	$ 556	$ 442	$25,546	$359	$ 4	$ 6,171	$34,036

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

Table of Contents

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

	Six Months Ended June 30,	
	2018	2017*
OPERATING ACTIVITIES		
Net income	$1,481	$689
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,191	1,117
Deferred income taxes	52	121
Non-cash compensation expense	41	38
Gain on Sunoco LP common unit repurchase	(172)	—
Loss on deconsolidation of CDM	86	—
Distributions on unvested awards	(17)	(15)
Equity in earnings of unconsolidated affiliates	(34)	(12)
Distributions from unconsolidated affiliates	215	197
Other non-cash	(122)	(98)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	229	(387)
Net cash provided by operating activities	2,950	1,650
INVESTING ACTIVITIES		
Cash proceeds from CDM contribution	1,227	—
Cash proceeds from Sunoco LP common unit repurchase	540	—
Cash proceeds from Bakken pipeline transaction	—	2,000
Cash paid for acquisition of PennTex noncontrolling interest	—	(280)
Cash paid for all other acquisitions	(29)	(261)
Capital expenditures, excluding allowance for equity funds used during construction	(3,409)	(2,842)
Contributions in aid of construction costs	60	10
Contributions to unconsolidated affiliates	(13)	(225)
Distributions from unconsolidated affiliates in excess of cumulative earnings	31	94
Proceeds from the sale of assets	2	25
Other	—	(7)
Net cash used in investing activities	(1,591)	(1,486)
FINANCING ACTIVITIES		
Proceeds from borrowings	12,476	11,466
Repayments of debt	(12,018)	(10,953)
Cash paid to affiliate notes	—	(255)
Common units issued for cash	39	990
Preferred units issued for cash	436	—
Capital contributions from noncontrolling interest	318	456
Distributions to partners	(2,011)	(1,702)
Distributions to noncontrolling interest	(359)	(186)
Repurchases of common units	(24)	—
Redemption of Legacy ETP Preferred Units	—	(53)
Debt issuance costs	(38)	(20)
Other	10	5
Net cash used in financing activities	(1,171)	(252)

Increase (decrease) in cash and cash equivalents	188	(88)
Cash and cash equivalents, beginning of period	306	360
Cash and cash equivalents, end of period	$494	$ 272

* As adjusted. See Note 1.

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

6

Table of Contents

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

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Energy Transfer Partners, L.P. ("ETP") is a consolidated subsidiary of ETE. In August 2018, ETE and ETP announced that they have entered into a definitive agreement providing for the merger of ETP with a wholly-owned subsidiary of ETE in a unit-for-unit exchange. In connection with the transaction, ETE's IDRs in ETP will be cancelled. Under the terms of the transaction, ETP unitholders (other than ETE and its subsidiaries) will receive 1.28 common units of ETE for each common unit of ETP they own. The transaction is expected to close in the fourth quarter of 2018, subject to the approval by a majority of the unaffiliated unitholders of ETP and other customary closing conditions.

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

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

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

- ETC OLP, Regency and PennTex, which are primarily engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP and Regency own and operate, through their wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and are engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, West Virginia, Colorado and Ohio.
- Energy Transfer Interstate Holdings, LLC, ("ETIH") with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales, which is the parent company of:
- Transwestern, engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC Fayetteville Express Pipeline, LLC, which directly owns a 50% interest in FEP, which owns 100% of the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger Pipeline, LLC, engaged in interstate transportation of natural gas.
- CrossCountry Energy, LLC, which indirectly owns a 50% interest in Citrus, which owns 100% of the FGT interstate natural gas pipeline.
- ETC Midcontinent Express Pipeline, L.L.C., which directly owns a 50% interest in MEP.
- ET Rover Pipeline, LLC, which ETIH directly owns a 50.1% interest in, which owns a 65% interest in the Rover pipeline.
- ETC Compression, LLC, engaged in natural gas compression services and related equipment sales. As discussed further in Note 2 below, in April 2018, we contributed certain assets to USAC.
- ETP Holdco, which indirectly owns Panhandle and Sunoco, Inc. Panhandle owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the transportation and storage of natural gas in the United States. Sunoco Inc.'s assets primarily consist of its ownership in Retail Holdings, which owns noncontrolling interests in Sunoco LP and PES. ETP Holdco also holds an equity method investment in ETP through its ownership of ETP Class E, Class G, and Class K units, which investment is eliminated in ETP's consolidated financial statements.

7

Table of Contents

- Sunoco Logistics Partners Operations L.P., which owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets, which are used to facilitate the purchase and sale of crude oil, NGLs and refined products.

We currently have the following reportable business segments:

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

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

Basis of Presentation

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

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

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

Change in Accounting Policy

Inventory Accounting Change

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

Table of Contents

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

	Three Months Ended June 30, 2017			Six Months Ended June 30, 2017		
	As Originally Reported	Effect of Change	As Adjusted	As Originally Reported	Effect of Change	As Adjusted
Cost of products sold [1]	$4,628	$ (4)	$ 4,624	$9,707	$ (33)	$ 9,674
Operating income	732	4	736	1,386	33	1,419
Income before income tax expense	371	4	375	790	33	823
Net income	292	4	296	656	33	689
Net income attributable to partners	199	3	202	523	10	533
Net loss per common unit – basic	(0.04)	—	(0.04)	(0.04)	0.02	(0.02)
Net loss per common unit – diluted	(0.04)	—	(0.04)	(0.04)	0.02	(0.02)
Comprehensive income	291	4	295	655	33	688
Comprehensive income attributable to partners	198	3	201	522	10	532

(1) As originally reported amounts reflect certain reclassifications made to conform to the current year presentation.

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

	Six Months Ended June 30, 2017		
	As Originally Reported	Effect of Change	As Adjusted
Net income	$656	$ 33	$ 689
Inventory valuation adjustments	56	(56)	—
Net change in operating assets and liabilities, net of effects from acquisitions (change in inventories)	(410)	23	(387)

Revenue Recognition Standard

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

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

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

Table of Contents

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

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

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

	Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
	As Reported	Balances Without Adoption of ASC 606	Effect of Change: Higher/(Lower)	As Reported	Balances Without Adoption of ASC 606	Effect of Change: Higher/(Lower)
Revenues:						
Natural gas sales	$1,024	$ 1,024	$ —	$2,086	$ 2,086	$ —
NGL sales	2,141	2,134	7	4,171	4,153	18
Crude sales	4,241	4,238	3	7,495	7,488	7
Gathering, transportation and other fees	1,464	1,611	(147)	2,861	3,194	(333)
Refined product sales	413	413	—	852	852	—
Other	127	127	—	225	225	—
Costs and expenses:						
Cost of products sold	$7,140	$ 7,287	$ (147)	$13,128	$ 13,461	$ (333)
Operating expenses	627	617	10	1,231	1,206	25

Additional disclosures related to revenue are included in Note 12.

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

10

guidance in current GAAP. This ASU is effective for financial statements issued for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. The Partnership is currently evaluating the impact that adopting this new standard will have on the consolidated financial statements and related disclosures.

ASU 2018-02

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

2. ACQUISITIONS AND OTHER INVESTING TRANSACTIONS

CDM Contribution

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

Prior to the CDM Contribution, the CDM entities were indirect wholly-owned subsidiaries of ETP. Beginning April 2018, ETP's consolidated financial statements reflected an equity method investment in USAC. CDM's assets and liabilities were not reflected as held for sale, nor were CDM's results reflected as discontinued operations in these financial statements. At June 30, 2018, the carrying value of ETP's investment in USAC was $399 million, which is reflected in the all other segment. ETP recorded a $86 million loss on the deconsolidation of CDM including a $45 million accrual related to the indemnification of USAC related to an ongoing CDM sales and use tax audit.

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

3. ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES

HPC

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

Sunoco LP

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

As of June 30, 2018, ETP owns 26.2 million Sunoco LP common units representing 31.8% of Sunoco LP's total outstanding common units. Our investment in Sunoco LP is reflected in the all other segment. As of June 30, 2018, the carrying value of our investment in Sunoco LP is $535 million.

USAC

As of June 30, 2018, ETP owns 19.2 million USAC common units and 6.4 million USAC Class B Units, together representing 26.6% of the limited partner interests in USAC. USAC provides compression services to producers, processors, gatherers and transporters of natural gas and crude oil. Our investment in USAC is reflected in the all other segment. As of June 30, 2018, the carrying value of our investment in USAC is $399 million.

11

Table of Contents

4. CASH AND CASH EQUIVALENTS

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

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

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

	Six Months Ended June 30,	
	2018	2017*
Accounts receivable	$236	$88
Accounts receivable from related companies	156	(115)
Inventories	299	160
Other current assets	(375)	77
Other non-current assets, net	(3)	(39)
Accounts payable	(465)	(286)
Accounts payable to related companies	(99)	131
Accrued and other current liabilities	249	(389)
Other non-current liabilities	(2)	7
Derivative assets and liabilities, net	233	(21)
Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidations	$229	$(387)

* As adjusted. See Note 1.

Non-cash investing and financing activities are as follows:

	Six Months Ended June 30,	
	2018	2017
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$1,007	$1,363
USAC limited partner interests received in the CDM Contribution (see Note 2)	411	—
NON-CASH FINANCING ACTIVITIES:		
Contribution of property, plant and equipment from noncontrolling interest	$—	$988

5. INVENTORIES

Inventories consisted of the following:

	June 30, 2018	December 31, 2017
Natural gas, NGLs and refined products	$434	$ 733
Crude oil	571	551
Spare parts and other	251	305
Total inventories	$1,256	$ 1,589

Table of Contents

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

6. FAIR VALUE MEASURES

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations as of June 30, 2018 was $33.64 billion and $33.90 billion, respectively. As of December 31, 2017, the aggregate fair value and carrying amount of our consolidated debt obligations was $34.28 billion and $33.09 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

We have commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the six months ended June 30, 2018, no transfers were made between any levels within the fair value hierarchy.

Table of Contents

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 June 30, 2018 and December 31, 2017 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2018	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$22	$ 22	$ —
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	11	11	—
Forward Physical Contracts	9	—	9
Power:			
Forwards	69	—	69
Options – Puts	1	1	—
NGLs – Forwards/Swaps	300	300	—
Total commodity derivatives	413	334	79
Other non-current assets	21	14	7
Total assets	$434	$ 348	$ 86
Liabilities:			
Interest rate derivatives	$(147)	$ —	$ (147)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(70)	(70)	—
Swing Swaps IFERC	(2)	(1)	(1)
Fixed Swaps/Futures	(14)	(14)	—
Forward Physical Contracts	(5)	—	(5)
Power – Forwards	(57)	—	(57)
NGLs – Forwards/Swaps	(316)	(316)	—
Refined Products – Futures	(5)	(5)	—
Crude – Forwards/Swaps	(307)	(307)	—
Total commodity derivatives	(776)	(713)	(63)
Total liabilities	$(923)	$ (713)	$ (210)

Table of Contents

	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
NGLs – Forwards/Swaps	191	191	—
Crude:			
Forwards/Swaps	2	2	—
Futures	2	2	—
Total commodity derivatives	320	276	44
Other non-current assets	21	14	7
Total assets	$ 341	$ 290	$ 51
Liabilities:			
Interest rate derivatives	$ (219)	$ —	$ (219)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(24)	(24)	—
Swing Swaps IFERC	(15)	(1)	(14)
Fixed Swaps/Futures	(57)	(57)	—
Forward Physical Swaps	(2)	—	(2)
Power – Forwards	(22)	—	(22)
NGLs – Forwards/Swaps	(186)	(186)	—
Refined Products – Futures	(25)	(25)	—
Crude:			
Forwards/Swaps	(6)	(6)	—
Futures	(1)	(1)	—
Total commodity derivatives	(338)	(300)	(38)
Total liabilities	$ (557)	$ (300)	$ (257)

7. NET INCOME (LOSS) PER LIMITED PARTNER UNIT

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

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017*	2018	2017*
Net income	$602	$296	$1,481	$689
Less: Income attributable to noncontrolling interest	170	94	334	156
Net income, net of noncontrolling interest	432	202	1,147	533
Series A Preferred Unitholders' interest in net income	15	—	30	—
Series B Preferred Unitholders' interest in net income	9	—	18	—
Series C Preferred Unitholders' interest in net income	6	—	6	—
General Partner's interest in net income	402	251	804	457
Class H Unitholder's interest in net income	—	—	—	93
Common Unitholders' interest in net income (loss)	—	(49)	289	(17)
Additional (earnings) distributions allocated to General Partner	(1)	15	(3)	12
Distributions on employee unit awards, net of allocation to General Partner	(7)	(6)	(15)	(13)
Net income (loss) available to Common Unitholders	$(8)	$(40)	$271	$(18)
Weighted average Common Units – basic	1,165.4	1,021.7	1,164.6	922.5
Basic net income (loss) per Common Unit	$(0.01)	$(0.04)	$0.23	$(0.02)
Weighted average Common Units – diluted	1,165.4	1,021.7	1,169.4	922.5
Diluted net income (loss) per Common Unit	$(0.01)	$(0.04)	$0.23	$(0.02)

* As adjusted. See Note 1.

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

8. DEBT OBLIGATIONS

ETP Senior Notes Offering and Redemption

In June 2018, ETP issued the following senior notes:

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

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

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

Table of Contents

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

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

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

Credit Facilities and Commercial Paper

ETP Five-Year Credit Facility

ETP's revolving credit facility (the "ETP Five-Year Credit Facility") 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 June 30, 2018, the ETP Five-Year Credit Facility had $1.23 billion outstanding, all of which was commercial paper. The amount available for future borrowings was $2.61 billion after taking into account letters of credit of $167 million. The weighted average interest rate on the total amount outstanding as of June 30, 2018 was 2.87%.

ETP 364-Day Facility

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

Bakken Credit Facility

In August 2016, ETP and Phillips 66 completed project-level financing of the Bakken pipeline. The $2.50 billion credit facility matures in August 2019 (the "Bakken Credit Facility"). As of June 30, 2018, the Bakken Credit Facility had $2.50 billion of outstanding borrowings. The weighted average interest rate on the total amount outstanding as of June 30, 2018 was 3.72%.

Compliance with Our Covenants

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

9. EQUITY

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

	Number of Units
Number of common units at December 31, 2017	1,164.1
Common units issued in connection with the distribution reinvestment plan	2.1
Common units issued in connection with certain transactions	1.3
Issuance of common units under equity incentive plans	0.1
Repurchases of common units in open-market transactions	(1.2)
Number of common units at June 30, 2018	1,166.4

Equity Distribution Program

During the six months ended June 30, 2018, there were no units issued under the Partnership's equity distribution agreement. As of June 30, 2018, $752 million of the Partnership's common units remained available to be issued under the Partnership's existing $1.00 billion equity distribution agreement.

Distribution Reinvestment Program

During the six months ended June 30, 2018, distributions of $39 million were reinvested under the Partnership's distribution reinvestment plan.

Table of Contents

Preferred Units
ETP issued 950,000 Series A Preferred Units and 550,000 Series B Preferred Units in November 2017.
Series C Preferred Units Issuance
In April 2018, ETP issued 18 million of its 7.375% Series C Preferred Units at a price of $25 per unit, resulting in total gross proceeds of $450 million. The proceeds were used to repay amounts outstanding under ETP’s revolving credit facility and for general partnership purposes.
Distributions on the Series C Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2023, at a rate of 7.375% per annum of the stated liquidation preference of $25. On and after May 15, 2023, distributions on the Series C Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.530% per annum. The Series C Preferred Units are redeemable at ETP’s option on or after May 15, 2023 at a redemption price of $25 per Series C Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.
Series D Preferred Units Issuance
In July 2018, ETP issued 17.8 million of its 7.625% Series D Preferred Units at a price of $25 per unit, resulting in total gross proceeds of $445 million. The proceeds were used to repay amounts outstanding under ETP’s revolving credit facility and for general partnership purposes.
Distributions on the Series D Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, August 15, 2023, at a rate of 7.625% per annum of the stated liquidation preference of $25. On and after August 15, 2023, distributions on the Series D Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.378% per annum. The Series D Preferred Units are redeemable at ETP’s option on or after August 15, 2023 at a redemption price of $25 per Series D Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.
Cash Distributions
Under our limited partnership agreement, within 45 days after the end of each quarter, the Partnership distributes all cash on hand at the end of the quarter, less reserves established by the general partner in its discretion. This is defined as “available cash” in the partnership agreement. The general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct the Partnership’s business. The Partnership will make quarterly distributions to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to the general partner.
Distributions on common units declared and/or paid by the Partnership subsequent to December 31, 2017 were as follows:

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

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

	Year Ending December 31,
2018 (remainder)	$ 69
2019	128
Each year beyond 2019	33

Table of Contents

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

Period Ended	Record Date	Payment Date	Rate
Series A Preferred Units			
December 31, 2017	February 1, 2018	February 15, 2018	$15.451
June 30, 2018	August 1, 2018	August 15, 2018	31.250
Series B Preferred Units			
December 31, 2017	February 1, 2018	February 15, 2018	$16.378
June 30, 2018	August 1, 2018	August 15, 2018	33.125
Series C Preferred Units			
June 30, 2018	August 1, 2018	August 15, 2018	$0.56337

Accumulated Other Comprehensive Income

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

	June 30, 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	12	5
Total AOCI, net of tax	$ 4	$ 3

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

10. INCOME TAXES

The Partnership's effective tax rate differs from the statutory rate primarily due to partnership earnings that are not subject to United States federal and most state income taxes at the partnership level. For the three and six months ended June 30, 2018, the Partnership's income tax benefit also reflected $3 million and $70 million, respectively, of deferred benefit adjustments as the result of a state statutory rate reduction.

11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Guarantee of Sunoco LP Notes

In connection with previous transactions whereby Retail Holdings contributed assets to Sunoco LP, Retail Holdings provided a limited contingent guarantee of collection, but not of payment, to Sunoco LP with respect to certain of Sunoco LP's senior notes and $2.035 billion aggregate principal for Sunoco LP's term loan due 2019. In December 2016, Retail Holdings contributed its interests in Sunoco LP, along with the assignment of the guarantee of Sunoco LP's senior notes, to its subsidiary, ETC M-A Acquisition LLC ("ETC M-A").

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

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

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

FERC Audit

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

Commitments

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Rental expense	$22	$ 19	$39	$ 39

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.

Table of Contents

On June 14, 2017, the Court ruled on SRST's and CRST's motions for partial summary judgment and the USACE's cross-motions for partial summary judgment. The Court concluded that the USACE had not violated trust duties owed to the Tribes and had generally complied with its obligations under the Clean Water Act, the Rivers and Harbors Act, the Mineral Leasing Act, the National Environmental Policy Act ("NEPA") and other related statutes; however, the Court remanded to the USACE three discrete issues for further analysis and explanation of its prior determinations under certain of these statutes. On May 3, 2018, the District Court ordered the USACE to file a status report by June 8, 2018 informing the Court when the USACE expects the remand process to be complete. On June 8, 2018, the USACE filed a status report stating that they will conclude the remand process by August 10, 2018. On August 7, 2018, the USACE informed the Court that they will need until August 31, 2018 to finish the remand process. 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 halt or suspend operation of the pipeline, we cannot assure this outcome. ETP cannot determine when or how these lawsuits will be resolved or the impact they may have on the Dakota Access project.

Mont Belvieu Incident

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

MTBE Litigation

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

As of June 30, 2018, Sunoco, Inc. is a defendant in six cases, including one case each initiated by the States of Maryland, Vermont and Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial

Table of Contents

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 (the "Regency Defendants"). On March 6, 2018, the Regency Defendants filed their Answer to Plaintiff's Verified Amended Class Action Complaint. Trial is currently set for September 23-27, 2019.

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

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

On January 27, 2014, a trial commenced between ETP against Enterprise Products Partners, L.P. and Enterprise Products Operating LLC (collectively, "Enterprise") and Enbridge (US) Inc. Trial resulted in a verdict in favor of ETP against Enterprise that consisted of $319 million in compensatory damages and $595 million in disgorgement to ETP. The jury also found that ETP owed Enterprise $1 million under a reimbursement agreement. On July 29, 2014, the trial court entered a final judgment in favor of ETP and awarded ETP $536 million, consisting of compensatory damages, disgorgement, and pre-judgment interest. The trial court also ordered that ETP shall be entitled to recover post-judgment interest and costs of court and that Enterprise is not entitled to any net recovery on its counterclaims. Enterprise filed a notice of appeal with the Court of Appeals. On July 18, 2017, the Court of Appeals issued its opinion and reversed the trial court's judgment. ETP's motion for rehearing to the Court of Appeals was denied. On June 8, 2018, the Texas Supreme Court ordered briefing on the merits. ETP's petition for review remains under consideration by the Texas Supreme Court.

Bayou Bridge

On January 11, 2018, environmental groups and a trade association filed suit against the USACE in the United States District Court for the Middle District of Louisiana. Plaintiffs allege that the USACE's issuance of permits authorizing the construction of the Bayou Bridge Pipeline through the Atchafalaya Basin ("Basin") violated the National

Environmental Policy Act, the Clean Water Act, and the Rivers and Harbors Act. They asked the district court to vacate these permits and to enjoin construction of the project through the Basin until the USACE corrects alleged deficiencies in its decision-making process. ETP, through its subsidiary Bayou Bridge Pipeline, LLC ("Bayou Bridge"), intervened on January 26, 2018. On March 27, 2018, Bayou Bridge filed an answer to the complaint.

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

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

Rover

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

Ohio EPA alleges that the Defendants illegally discharged millions of gallons of drilling fluids into Ohio's waters that caused pollution and degraded water quality, and that the Defendants harmed pristine wetlands in Stark County. Ohio EPA further alleges that the Defendants caused the degradation of Ohio's waters by discharging pollution in the form of sediment-laden storm water into Ohio's waters and that Rover violated its hydrostatic permits by discharging effluent with greater levels of pollutants than those permits allowed and by not properly sampling or monitoring effluent for required parameters or reporting those alleged violations. Defendants' motions to dismiss are due on or before September 10, 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 the FERC and stated, among other things, that as Ohio EPA conceded, Rover was conducting its drilling operations in accordance with specified procedures that had been approved by the FERC and reviewed by the Ohio EPA. In addition, although the HDD operations were crossing the same resource as that which led to an inadvertent release of drilling fluids in April 2017, the drill in 2018 had been redesigned since the original crossing. Ohio EPA expressed concern that the drilling fluids could deprive organisms in the wetland of oxygen. Rover, however, has now fully remediated the site, a fact with which Ohio EPA concurs.

Other Litigation and Contingencies

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of June 30, 2018 and December 31, 2017, accruals of approximately $52 million and $53 million, respectively, were reflected on our consolidated balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

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

On April 25, 2018, and as amended on April 30, 2018, State Senator Andrew Dinniman filed a Formal Complaint and Petition for Interim Emergency Relief (“Complaint”) against Sunoco Pipeline L.P. (“SPLP”) before the Pennsylvania Public Utility Commission (“PUC”). Specifically, the Complaint alleges that (i) the services and facilities provided by the Mariner East Pipeline (“ME1,” “ME2” or “ME2x”) in West Whiteland Township (“the Township”) are unreasonable, unsafe, inadequate, and insufficient for, among other reasons, selecting an improper and unsafe route through densely populated portions of the Township with homes, schools, and infrastructure and causing inadvertent returns and sinkholes during construction because of unstable geology in the Township; (ii) SPLP failed to warn the public of the dangers of the pipeline; (iii) the construction of ME2 and ME2x increases the risk of damage to the existing co-located ME1 pipeline; and (iv) ME1, ME2 and ME2x are

Table of Contents

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 SPLP fully assesses and the PUC approves the condition, adequacy, efficiency, safety, and reasonableness of those pipelines and the geology in which they sit; (iv) requiring SPLP to release to the public its written integrity management plan and risk analysis for these pipelines; and (v) finding that these pipelines are not public utility facilities. In short, the relief, if granted, would continue the suspension of operation of ME1 and suspend further construction of ME2 and ME2x in West Whiteland Township.

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

Service on ME1 was resumed in accordance with PUC's Opinion and Order. Senator Dinniman's Complaint will proceed forward under a schedule to be determined by the ALJ. A prehearing conference with the ALJ is scheduled for August 28, 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. On July 31, 2018 the underlying permit appeals in which the above settlements occurred were withdrawn in a settlement between the appellants and PADEP. That settlement did not involve SPLP.

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

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

Environmental Matters

Our operations are subject to extensive federal, tribal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations but there can be no assurance that such costs will not

Table of Contents

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 SPLP and Mid-Valley Pipeline Company (“Mid-Valley”) that enforcement actions were being pursued for three crude oil releases: (a) an estimated 550 barrels released from the Colmesneil-to-Chester pipeline in Tyler County, Texas (“Colmesneil”) operated and owned by SPLP in February 2013; (b) an estimated 4,509 barrels released from the Longview-to-Mayersville pipeline in Caddo Parish, Louisiana (a/k/a Milepost 51.5) operated by SPLP and owned by Mid-Valley in October 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma operated and owned by SPLP in January 2015. In May 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. Since then, the parties have reached an agreement in principal to resolve all penalties. 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 SPLP directing that work on the Mariner East 2 and 2X pipelines be stopped. The Administrative Order detailed alleged violations of the permits issued by PADEP in February 2017, during the construction of the project. SPLP began working with PADEP representatives immediately after the Administrative Order was issued to resolve the compliance issues. Those compliance issues could not be fully resolved by the deadline to appeal the Administrative Order, so SPLP took an appeal of the Administrative Order to the Pennsylvania Environmental Hearing Board on February 2, 2018. On February 8, 2018, SPLP entered into a Consent Order and Agreement with PADEP that (i) withdraws the Administrative Order; (ii) establishes requirements for compliance with permits on a going forward basis; (iii) resolves the non-compliance alleged in the Administrative Order; and (iv) conditions restart of work on an agreement by SPLP to pay a $12.6 million civil penalty to the Commonwealth of Pennsylvania. In the Consent Order and agreement, SPLP admits to the factual allegations, but does not admit to the conclusions of law that were made by PADEP. PADEP also found in the Consent Order and Agreement that SPLP had adequately addressed the issues raised in the Administrative Order and demonstrated an ability to comply with the permits. SPLP concurrently filed a request to the Pennsylvania Environmental Hearing Board to discontinue the appeal of the Administrative Order. That request was granted on February 8, 2018.

Environmental Remediation

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

- certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of polychlorinated biphenyls (“PCBs”). PCB assessments are ongoing and, in some cases, our subsidiaries could potentially be held responsible for contamination caused by other parties.

- certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- legacy sites related to Sunoco, Inc. that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that Sunoco, Inc. no longer operates, closed and/or sold refineries and other formerly owned sites.

Table of Contents

- 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 June 30, 2018, Sunoco, Inc. had been named as a PRP at approximately 41 identified or potentially identifiable "Superfund" sites under federal and/or comparable state law. Sunoco, Inc. is usually one of a number of companies identified as a PRP at a site. Sunoco, Inc. has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon Sunoco, Inc.'s purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

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

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

	June 30, 2018	December 31, 2017
Current	$ 42	$ 36
Non-current	276	314
Total environmental liabilities	$ 318	$ 350

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

During the three months ended June 30, 2018 and 2017, the Partnership recorded $6 million and $7 million, respectively, of expenditures related to environmental cleanup programs. During the six months ended June 30, 2018 and 2017, the Partnership recorded $11 million and $13 million, respectively, of expenditures related to environmental 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.

Table of Contents

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.

12. REVENUE

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

Disaggregation of revenue

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

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

Note 15 depicts the disaggregation of revenue by segment, with revenue amounts reflected in accordance with ASC Topic 606 for 2018 and ASC Topic 605 for 2017.

Intrastate transportation and storage revenue

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

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

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

Interstate transportation and storage revenue

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

Table of Contents

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

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

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

Midstream revenue

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

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

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

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

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

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

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

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

NGL and refined products transportation and services revenue

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

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

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

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

Crude oil transportation and services revenue

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

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

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

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

Table of Contents

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

All other revenue

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

Contract Balances with Customers

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

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

The Partnership recognizes a contract liability if the customer's payment of consideration precedes the Partnership's fulfillment of the performance obligations. Certain contracts contain provisions requiring customers to pay a fixed fee for a right to use our assets, but allows customers to apply such fees against services to be provided at a future point in time. These amounts are reflected as deferred revenue until the customer applies the deficiency fees to services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints. As of June 30, 2018, the Partnership had $235 million in deferred revenues representing the current value of our future performance obligations.

The amount of revenue recognized for the three and six months ended June 30, 2018 that was included in the deferred revenue liability balance as of January 1, 2018 was $28 million and $63 million, respectively.

Performance Obligations

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

As of June 30, 2018, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations is $40.32 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 June 30, 2018	$ 2,598	$5,048	$4,604	$ 28,071	$40,321

Practical Expedients Utilized by the Partnership

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

- Right to invoice: The Partnership elected to utilize an output method to recognize revenue that is based on the amount to which the Partnership has a right to invoice a customer for services performed to date, if that amount corresponds

Table of Contents

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.

13. DERIVATIVE ASSETS AND LIABILITIES

Commodity Price Risk

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

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

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

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

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

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

Table of Contents

The following table details our outstanding commodity-related derivatives:

	June 30, 2018		December 31, 2017	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	465	2018	1,078	2018
Basis Swaps IFERC/NYMEX [(1)]	102,328	2018-2020	48,510	2018-2020
Options – Puts	(3,043)	2018	13,000	2018
Power (Megawatt):				
Forwards	3,196,100	2018-2019	435,960	2018-2019
Futures	(42,768)	2018	(25,760)	2018
Options – Puts	(30,532)	2018	(153,600)	2018
Options – Calls	996,172	2018	137,600	2018
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	6,600	2018-2020	4,650	2018-2020
Swing Swaps IFERC	52,413	2018-2019	87,253	2018-2019
Fixed Swaps/Futures	5,360	2018-2019	(4,700)	2018-2019
Forward Physical Contracts	(174,465)	2018-2020	(145,105)	2018-2020
NGL (MBbls) – Forwards/Swaps	(1,590)	2018-2019	(2,493)	2018-2019
Crude (MBbls) – Forwards/Swaps	44,190	2018-2019	9,172	2018-2019
Refined Products (MBbls) – Futures	(1,076)	2018-2019	(3,783)	2018-2019
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(21,475)	2018	(39,770)	2018
Fixed Swaps/Futures	(21,475)	2018	(39,770)	2018
Hedged Item – Inventory	21,475	2018	39,770	2018

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

Interest Rate Risk

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

Table of Contents

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

Term	Type[(1)]	Notional Amount Outstanding June 30, 2018	Notional Amount Outstanding December 31, 2017
July 2018[(2)]	Forward-starting to pay a fixed rate of 3.76% and receive a floating rate	$ —	$ 300
July 2019[(2)]	Forward-starting to pay a fixed rate of 3.56% and receive a floating rate	400	300
July 2020[(2)]	Forward-starting to pay a fixed rate of 3.52% and receive a floating rate	400	400
July 2021[(2)]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	400	—
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300

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

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

Credit Risk

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

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

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

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

Table of Contents

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2018	December 31, 2017	June 30, 2018	December 31, 2017
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$—	$ 14	$(2)	$ (2)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	307	262	(352)	(281)
Commodity derivatives	106	44	(422)	(55)
Interest rate derivatives	—	—	(147)	(219)
	413	306	(921)	(555)
Total derivatives	$413	$ 320	$(923)	$ (557)

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

	Balance Sheet Location	Asset Derivatives		Liability Derivatives	
		June 30, 2018	December 31, 2017	June 30, 2018	December 31, 2017
Derivatives without offsetting agreements	Derivative liabilities	$—	$ —	$(147)	$ (219)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	106	44	(422)	(55)
Broker cleared derivative contracts	Other current assets (liabilities)	307	276	(354)	(283)
Total gross derivatives		413	320	(923)	(557)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(49)	(20)	49	20
Counterparty netting	Other current assets (liabilities)	(306)	(263)	306	263
Total net derivatives		$58	$ 37	$(568)	$ (274)

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

Table of Contents

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

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income Representing Hedge Ineffectiveness and Amount Excluded from the Assessment of Effectiveness			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2018	2017	2018	2017
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ 6	$ 6	$ 9	$ 2

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2018	2017	2018	2017
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$ 16	$ 15	$ 33	$ 26
Commodity derivatives – Non-trading	Cost of products sold	(300)	7	(373)	(3)
Interest rate derivatives	Gains (losses) on interest rate derivatives	20	(25)	72	(20)
Embedded derivatives	Other, net	—	—	—	1
Total		$ (264)	$ (3)	$ (268)	$ 4

14. RELATED PARTY TRANSACTIONS

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Affiliated revenues	$ 222	$ 133	$ 508	$ 251

Table of Contents

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

	June 30, 2018	December 31, 2017
Accounts receivable from related companies:		
Sunoco LP	$ 184	$ 219
FGT	18	11
Other	132	88
Total accounts receivable from related companies:	$ 334	$ 318
Accounts payable to related companies:		
Sunoco LP	$ 195	$ 195
USAC	45	—
Other	89	14
Total accounts payable to related companies:	$ 329	$ 209

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

15. REPORTABLE SEGMENTS

Our financial statements currently reflect the following reportable segments, which conduct their business in the United States, as follows:

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

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

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

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

Table of Contents

The following tables present financial information by segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$761	$699	$1,578	$1,467
Intersegment revenues	52	54	110	102
	813	753	1,688	1,569
Interstate transportation and storage:				
Revenues from external customers	323	201	636	432
Intersegment revenues	5	6	8	10
	328	207	644	442
Midstream:				
Revenues from external customers	594	633	1,034	1,198
Intersegment revenues	1,280	982	2,454	2,054
	1,874	1,615	3,488	3,252
NGL and refined products transportation and services:				
Revenues from external customers	2,472	1,767	4,930	3,885
Intersegment revenues	96	12	184	160
	2,568	1,779	5,114	4,045
Crude oil transportation and services:				
Revenues from external customers	4,789	2,460	8,520	5,035
Intersegment revenues	14	5	28	5
	4,803	2,465	8,548	5,040
All other:				
Revenues from external customers	471	816	992	1,454
Intersegment revenues	31	54	81	186
	502	870	1,073	1,640
Eliminations	(1,478)	(1,113)	(2,865)	(2,517)
Total revenues	$9,410	$6,576	$17,690	$13,471

Table of Contents

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017*	2018	2017*
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$208	$148	$400	$317
Interstate transportation and storage	330	262	653	527
Midstream	414	412	791	732
NGL and refined products transportation and services	461	388	912	769
Crude oil transportation and services	548	228	1,012	415
All other	90	107	164	230
Total	2,051	1,545	3,932	2,990
Depreciation, depletion and amortization	(588)	(557)	(1,191)	(1,117)
Interest expense, net	(358)	(336)	(704)	(668)
Gain on Sunoco LP common unit repurchase	—	—	172	—
Loss on deconsolidation of CDM	(86)	—	(86)	—
Gains (losses) on interest rate derivatives	20	(25)	72	(20)
Non-cash compensation expense	(21)	(15)	(41)	(38)
Unrealized gains (losses) on commodity risk management activities	(265)	34	(352)	98
Adjusted EBITDA related to unconsolidated affiliates	(228)	(247)	(413)	(486)
Equity in earnings (losses) of unconsolidated affiliates	106	(61)	34	12
Other, net	40	37	87	52
Income before income tax expense	$671	$375	$1,510	$823

* As adjusted. See Note 1.

	June 30, 2018	December 31, 2017
Assets:		
Intrastate transportation and storage	$5,604	$ 5,020
Interstate transportation and storage	14,037	13,518
Midstream	19,949	20,004
NGL and refined products transportation and services	17,517	17,600
Crude oil transportation and services	18,168	17,736
All other	3,295	4,087
Total assets	$78,570	$ 77,965

16. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

Sunoco Logistics Partners Operations L.P., a subsidiary of ETP, is the issuer of multiple series of senior notes that are guaranteed by ETP. These guarantees are full and unconditional. For the purposes of this footnote, Energy Transfer Partners, L.P. is referred to as “Parent Guarantor” and Sunoco Logistics Partners Operations L.P. is referred to as “Subsidiary Issuer.” All other consolidated subsidiaries of the Partnership are collectively referred to as “Non-Guarantor Subsidiaries.”

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

38

Table of Contents

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

	June 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash and cash equivalents	$—	$—	$ 494	$—	$ 494
All other current assets	—	57	8,527	(2,531)	6,053
Property, plant and equipment, net	—	—	59,776	—	59,776
Investments in unconsolidated affiliates	51,199	12,078	3,636	(63,277)	3,636
All other assets	8	—	8,603	—	8,611
Total assets	$51,207	$12,135	$ 81,036	$(65,808)	$ 78,570
Current liabilities	$390	$(3,571)	$ 12,353	$(2,531)	$ 6,641
Non-current liabilities	22,949	7,606	7,338	—	37,893
Noncontrolling interest	—	—	6,171	—	6,171
Total partners’ capital	27,868	8,100	55,174	(63,277)	27,865
Total liabilities and equity	$51,207	$12,135	$ 81,036	$(65,808)	$ 78,570

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

Table of Contents

	Three Months Ended June 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$ —	$ 9,410	$ —	$ 9,410
Operating costs, expenses, and other	—	—	8,467	—	8,467
Operating income	—	—	943	—	943
Interest expense, net	(289)	(41)	(28)	—	(358)
Equity in earnings of unconsolidated affiliates	701	66	106	(767)	106
Gains on interest rate derivatives	20	—	—	—	20
Loss on deconsolidation of CDM	—	—	(86)	—	(86)
Other, net	—	—	46	—	46
Income before income tax expense	432	25	981	(767)	671
Income tax expense	—	—	69	—	69
Net income	432	25	912	(767)	602
Less: Net income attributable to noncontrolling interest	—	—	170	—	170
Net income attributable to partners	$432	$ 25	$ 742	$ (767)	$ 432
Other comprehensive income	$—	$ —	$ 2	$ —	$ 2
Comprehensive income	432	25	914	(767)	604
Comprehensive income attributable to noncontrolling interest	—	—	170	—	170
Comprehensive income attributable to partners	$432	$ 25	$ 744	$ (767)	$ 434

	Three Months Ended June 30, 2017*				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$ —	$ 6,576	$ —	$ 6,576
Operating costs, expenses, and other	—	1	5,839	—	5,840
Operating income (loss)	—	(1)	737	—	736
Interest expense, net	—	(39)	(297)	—	(336)
Equity in earnings (losses) of unconsolidated affiliates	199	137	(61)	(336)	(61)
Losses on interest rate derivatives	—	—	(25)	—	(25)
Other, net	—	3	59	(1)	61
Income before income tax expense	199	100	413	(337)	375
Income tax expense	—	—	79	—	79
Net income	199	100	334	(337)	296
Less: Net income attributable to noncontrolling interest	—	—	94	—	94
Net income attributable to partners	$199	$ 100	$ 240	$ (337)	$ 202
Other comprehensive loss	$—	$ —	$ (1)	$ —	$ (1)
Comprehensive income	199	100	333	(337)	295
Comprehensive income attributable to noncontrolling interest	—	—	94	—	94
Comprehensive income attributable to partners	$199	$ 100	$ 239	$ (337)	$ 201

* As adjusted. See Note 1.

Table of Contents

	Six Months Ended June 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$ —	$ 17,690	$ —	$ 17,690
Operating costs, expenses, and other	—	—	15,774	—	15,774
Operating income	—	—	1,916	—	1,916
Interest expense, net	(567)	(82)	(55)	—	(704)
Equity in earnings of unconsolidated affiliates	1,642	326	34	(1,968)	34
Gains on interest rate derivatives	72	—	—	—	72
Gain on Sunoco LP unit repurchase	—	—	172	—	172
Loss on deconsolidation of CDM	—	—	(86)	—	(86)
Other, net	—	—	106	—	106
Income before income tax expense	1,147	244	2,087	(1,968)	1,510
Income tax expense	—	—	29	—	29
Net income	1,147	244	2,058	(1,968)	1,481
Less: Net income attributable to noncontrolling interest	—	—	334	—	334
Net income attributable to partners	$1,147	$ 244	$ 1,724	$ (1,968)	$ 1,147
Other comprehensive income	$—	$ —	$ 3	$ —	$ 3
Comprehensive income	1,147	244	2,061	(1,968)	1,484
Comprehensive income attributable to noncontrolling interest	—	—	334	—	334
Comprehensive income attributable to partners	$1,147	$ 244	$ 1,727	$ (1,968)	$ 1,150

	Six Months Ended June 30, 2017*				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$ —	$ 13,471	$ —	$ 13,471
Operating costs, expenses, and other	—	1	12,051	—	12,052
Operating income (loss)	—	(1)	1,420	—	1,419
Interest expense, net	—	(81)	(587)	—	(668)
Equity in earnings of unconsolidated affiliates	1,010	765	12	(1,775)	12
Losses on interest rate derivatives	—	—	(20)	—	(20)
Other, net	—	3	78	(1)	80
Income before income tax expense	1,010	686	903	(1,776)	823
Income tax expense	—	—	134	—	134
Net income	1,010	686	769	(1,776)	689
Less: Net income attributable to noncontrolling interest	—	—	156	—	156
Net income attributable to partners	$1,010	$ 686	$ 613	$ (1,776)	$ 533
Other comprehensive loss	$—	$ —	$ (1)	$ —	$ (1)
Comprehensive income	1,010	686	768	(1,776)	688
Comprehensive income attributable to noncontrolling interest	—	—	156	—	156
Comprehensive income attributable to partners	$1,010	$ 686	$ 612	$ (1,776)	$ 532

* As adjusted. See Note 1.

Table of Contents

	Six Months Ended June 30, 2018				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$3,252	$ 102	$ 585	$ (989)	$ 2,950
Cash flows used in investing activities	(2,925)	(99)	(903)	2,336	(1,591)
Cash flows provided by (used in) financing activities	(327)	—	503	(1,347)	(1,171)
Change in cash	—	3	185	—	188
Cash at beginning of period	—	(3)	309	—	306
Cash at end of period	$—	$ —	$ 494	$ —	$ 494

	Six Months Ended June 30, 2017				
	Parent Guarantor	Subsidiary Issuer	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows provided by operating activities	$1,010	$ 652	$ 1,764	$ (1,776)	$ 1,650
Cash flows used in investing activities	(716)	(421)	(2,125)	1,776	(1,486)
Cash flows provided by (used in) financing activities	(294)	(249)	291	—	(252)
Change in cash	—	(18)	(70)	—	(88)
Cash at beginning of period	—	41	319	—	360
Cash at end of period	$—	$ 23	$ 249	$ —	$ 272

Table of Contents

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

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

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with (i) our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q; and (ii) the consolidated financial statements and management's discussion and analysis of financial condition and results of operations included in the Partnership's Annual Report on Form 10-K filed with the SEC on February 23, 2018. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Part I – Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on February 23, 2018.

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

OVERVIEW

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

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

RECENT DEVELOPMENTS

ETE and ETP Simplification Transaction

In August 2018, ETE and ETP announced that they have entered into a definitive agreement providing for the merger of ETP with a wholly-owned subsidiary of ETE in a unit-for-unit exchange. In connection with the transaction, ETE's IDRs in ETP will be cancelled. Under the terms of the transaction, ETP unitholders (other than ETE and its subsidiaries) will receive 1.28 common units of ETE for each common unit of ETP they own. The transaction is expected to close in the fourth quarter of 2018, subject to the approval by a majority of the unaffiliated unitholders of ETP and other customary closing conditions.

Series D Preferred Units Issuance

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

ETP Senior Notes Offering and Redemption

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

Old Ocean Joint Venture Formation

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

Table of Contents

Acquisition of HPC

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

Series C Preferred Units Issuance

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

CDM Contribution

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

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

New Ethane Export Facility Joint Venture

In March 2018, ETP and Satellite Petrochemical USA Corp. ("Satellite") entered into definitive agreements to form a joint venture, Orbit Gulf Coast NGL Exports, LLC ("Orbit"), with the purpose of constructing a new export terminal on the United States Gulf Coast to provide ethane to Satellite for consumption at their ethane cracking facilities in China. At the terminal, Orbit will construct an 800 MBbls refrigerated ethane storage tank, a 175 MBbls/d ethane refrigeration facility and a 20-inch ethane pipeline originating at ETP's Mont Belvieu Fractionators that will make deliveries to the terminal as well as domestic markets in the region. ETP will be the operator of the Orbit assets, provide storage and marketing services for Satellite and provide Satellite with approximately 150 MBbls/d of ethane under a long-term, demand-based agreement. Additionally, ETP will construct and wholly own the infrastructure that is required to both supply ethane to the pipeline and to load the ethane on to very large ethane carriers destined for Satellite's newly constructed ethane crackers in China's Jiangsu Province. Subject to Chinese Governmental approval, it is anticipated that the Orbit export terminal will be ready for commercial service in the fourth quarter of 2020.

Sunoco LP Common Unit Repurchase

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

Regulatory Update

Interstate Natural Gas Transportation Regulation

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

Table of Contents

to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs. In light of the rehearing order, the impacts of the FERC's policy on the treatment of income taxes may have on the rates the ETP can charge for the FERC regulated transportation services are unknown at this time.

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

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

Even without action on the NOI or as contemplated in the Final Rule, the FERC or our shippers may challenge the cost of service rates we charge. The FERC's establishment of a just and reasonable rate is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect the FERC's determination of just and reasonable cost of service rates. Although changes in these two tax related components may decrease, other components in the cost of service rate calculation may increase and result in a newly calculated cost of service rate that is the same as or greater than the prior cost of service rate. Moreover, we receive revenues from our pipelines based on a variety of rate structures, including cost of service rates, negotiated rates, discounted rates and market-based rates. Many of our interstate pipelines, such as ETC Tiger Pipeline, LLC, MEP and FEP, have negotiated market rates that were agreed to by customers in connection with long-term contracts entered into to support the construction of the pipelines. Other systems, such as FGT, Transwestern and Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. We do not expect market-based rates, negotiated rates or discounted rates that are not tied to the cost of service rates to be affected by the Revised Policy Statement or any final regulations that may result from the March 15, 2018 proposals. The revenues we receive from natural gas transportation services we provide pursuant to cost of service based rates may decrease in the future as a result of the ultimate outcome of the NOI, the Final Rule, and the Revised Policy Statement, combined with the reduced corporate federal income tax rate established in the Tax Act. The extent of any revenue reduction related to our cost of service rates, if any, will depend on a detailed review of all of ETP's cost of service components and the outcomes of any challenges to our rates by the FERC or our shippers.

The FERC issued a Notice of Inquiry on April 19, 2018 ("Pipeline Certification NOI"), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on

Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed as a result of the Pipeline Certification NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. Comments in response to the Pipeline Certification NOI were due on or before July 25, 2018. We do not expect that any change in this policy would affect us in a materially different manner than any other natural gas pipeline company operating in the United States.

Interstate Liquids Transportation Regulation

The FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index, or PPI. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. The FERC’s indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI plus 1.23 percent. Many existing pipelines utilize the FERC liquids

Table of Contents

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 the FERC in its next five year review of the liquids pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Act in the determination of indexed rates prospectively, effective July 1, 2021. The FERC’s establishment of a just and reasonable rate, including the determination of the appropriate liquids pipeline index, is based on many components, and tax related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect the FERC’s determination of the appropriate pipeline index. Accordingly, depending on the FERC’s application of its indexing rate methodology for the next five year term of index rates, the Revised Policy Statement and tax effects related to the Tax Act may impact our revenues associated with any transportation services we may provide pursuant to cost of service based rates in the future, including indexed rates.

Results of Operations

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

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

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

Table of Contents

Consolidated Results

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017*	Change	2018	2017*	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$208	$148	$60	$400	$317	$83
Interstate transportation and storage	330	262	68	653	527	126
Midstream	414	412	2	791	732	59
NGL and refined products transportation and services	461	388	73	912	769	143
Crude oil transportation and services	548	228	320	1,012	415	597
All other	90	107	(17)	164	230	(66)
Total	2,051	1,545	506	3,932	2,990	942
Depreciation, depletion and amortization	(588)	(557)	(31)	(1,191)	(1,117)	(74)
Interest expense, net	(358)	(336)	(22)	(704)	(668)	(36)
Gain on Sunoco LP common unit repurchase	—	—	—	172	—	172
Loss on deconsolidation of CDM	(86)	—	(86)	(86)	—	(86)
Gains (losses) on interest rate derivatives	20	(25)	45	72	(20)	92
Non-cash compensation expense	(21)	(15)	(6)	(41)	(38)	(3)
Unrealized gains (losses) on commodity risk management activities	(265)	34	(299)	(352)	98	(450)
Adjusted EBITDA related to unconsolidated affiliates	(228)	(247)	19	(413)	(486)	73
Equity in earnings (losses) of unconsolidated affiliates	106	(61)	167	34	12	22
Other, net	40	37	3	87	52	35
Income before income tax expense	671	375	296	1,510	823	687
Income tax expense	(69)	(79)	10	(29)	(134)	105
Net income	$602	$296	$306	$1,481	$689	$792

* As adjusted.

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

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased for the three and six months ended June 30, 2018 compared to the same period last year primarily due to additional depreciation from assets recently placed in service. These increases were partially offset by the deconsolidation of CDM in April 2018, which reduced depreciation and amortization expense by $41 million for the three and six months ended June 30, 2018 compared to the prior periods.

Interest Expense, net. Interest expense, net of capitalized interest, increased for the three and six months ended June 30, 2018 compared to the same period last year primarily attributable to increases in long-term debt from ETP senior note issuances, partially offset by a decrease in credit facility borrowings and an increase in capitalized interest of $15 million and $36 million, respectively, for the three and six months ended June 30, 2018 compared to the prior periods.

Gain on Sunoco LP Common Unit Repurchase. In connection with Sunoco LP's repurchase of its common units in February 2018, the Partnership recognized a gain of $172 million.

Loss on Deconsolidation of CDM. In connection with the CDM Contribution in April 2018, the Partnership deconsolidated CDM and recognized a loss of $86 million.

Table of Contents

Gains (Losses) on Interest Rate Derivatives. Gains on interest rate derivatives during the three and six months ended June 30, 2018 resulted from increases in forward interest rates, which caused our forward-starting swaps to change in value.

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

Adjusted EBITDA Related to Unconsolidated Affiliates and Equity in Earnings (Losses) of Unconsolidated Affiliates. See additional information in “Supplemental Information on Unconsolidated Affiliates” and “Segment Operation Results” below.

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

Income Tax Expense. For the three and six months ended June 30, 2018 compared to the same period last year, income tax expense decreased primarily due to the decrease in federal corporate income tax rate per the Tax Act as well as $3 million and $70 million, respectively, of deferred tax benefit adjustments during the three and six months ended June 30, 2018 as the result of a state statutory rate reduction.

Table of Contents

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$33	$30	$ 3	$60	$51	$ 9
FEP	13	13	—	27	25	2
MEP	8	10	(2)	17	20	(3)
Sunoco LP	16	(110)	126	(135)	(124)	(11)
USAC	(2)	—	(2)	(2)	—	(2)
Other	38	(4)	42	67	40	27
Total equity in earnings (losses) of unconsolidated affiliates	$106	$(61)	$ 167	$34	$12	$ 22
Adjusted EBITDA related to unconsolidated affiliates[(1)]:						
Citrus	$85	$88	$ (3)	$160	$163	$ (3)
FEP	18	19	(1)	37	37	—
MEP	20	21	(1)	42	43	(1)
Sunoco LP	39	83	(44)	68	137	(69)
USAC	21	—	21	21	—	21
Other	45	36	9	85	106	(21)
Total Adjusted EBITDA related to unconsolidated affiliates	$228	$247	$ (19)	$413	$486	$ (73)
Distributions received from unconsolidated affiliates:						
Citrus	$27	$22	$ 5	$73	$63	$ 10
FEP	15	10	5	32	10	22
MEP	18	20	(2)	31	93	(62)
Sunoco LP	22	37	(15)	58	72	(14)
USAC	10	—	10	10	—	10
Other	21	30	(9)	42	53	(11)
Total distributions received from unconsolidated affiliates	$113	$119	$ (6)	$246	$291	$ (45)

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

Segment Operating Results

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

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

- Segment margin, operating expenses, and selling, general and administrative expenses. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.

Table of Contents

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

In the following analysis of segment operating results, a measure of segment margin is reported for segments with sales revenues. Segment margin is a non-GAAP financial measure and is presented herein to assist in the analysis of segment operating results and particularly to facilitate an understanding of the impacts that changes in sales revenues have on the segment performance measure of Segment Adjusted EBITDA. Segment margin is similar to the GAAP measure of gross margin, except that segment margin excludes charges for depreciation, depletion and amortization. In addition, for certain segments, the sections below include information on the components of segment margin by sales type, which components are included in order to provide additional disaggregated information to facilitate the analysis of segment margin and Segment Adjusted EBITDA. For example, these components include transportation margin, storage margin, and other margin. These components of segment margin are calculated consistent with the calculation of segment margin; therefore, these components also exclude charges for depreciation, depletion and amortization.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Intrastate transportation and storage	$267	$202	$438	$384
Interstate transportation and storage	328	207	644	$442
Midstream	593	571	1,146	1,084
NGL and refined products transportation and services	587	516	1,187	1,075
Crude oil transportation and services	442	374	1,010	646
All other	57	76	152	178
Intersegment eliminations	(4)	6	(15)	(12)
Total segment margin	2,270	1,952	4,562	3,797
Less:				
Operating expenses	627	539	1,231	1,031
Depreciation, depletion and amortization	588	557	1,191	1,117
Selling, general and administrative	112	120	224	230
Operating income	$943	$736	$1,916	$1,419

Table of Contents

Intrastate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Natural gas transported (BBtu/d)	10,327	9,261	1,066	9,802	8,569	1,233
Withdrawals from storage natural gas inventory (BBtu)	—	—	—	17,703	23,093	(5,390)
Revenues	$813	$753	$ 60	$1,688	$1,569	$ 119
Cost of products sold	546	551	(5)	1,250	1,185	65
Segment margin	267	202	65	438	384	54
Unrealized (gains) losses on commodity risk management activities	(8)	(21)	13	45	(6)	51
Operating expenses, excluding non-cash compensation expense	(51)	(46)	(5)	(90)	(84)	(6)
Selling, general and administrative expenses, excluding non-cash compensation expense	(7)	(5)	(2)	(13)	(11)	(2)
Adjusted EBITDA related to unconsolidated affiliates	7	18	(11)	20	34	(14)
Segment Adjusted EBITDA	$208	$148	$ 60	$400	$317	$ 83

Volumes. For the three and six months ended June 30, 2018 compared to the same period last year, transported volumes increased primarily due to favorable market pricing. In addition, beginning in April 2018, transported volumes also reflected RIGS as a consolidated subsidiary, as discussed in "Recent Developments" above.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Transportation fees	$134	$104	$ 30	$251	$228	$ 23
Natural gas sales and other (excluding unrealized gains and losses)	108	61	47	199	94	105
Retained fuel revenues (excluding unrealized gains and losses)	13	15	(2)	26	28	(2)
Storage margin (excluding unrealized gains and losses)	4	1	3	7	28	(21)
Unrealized gains (losses) on commodity risk management activities	8	21	(13)	(45)	6	(51)
Total segment margin	$267	$202	$ 65	$438	$384	$ 54

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

- an increase of $47 million in realized natural gas sales and other margin due to higher realized gains from pipeline optimization activity;
- a net increase of $5 million due to the consolidation of RIGS beginning in April 2018, as discussed in "Recent Developments" above, resulting in increases in transportation fees, operating expenses, and selling, general and administrative expenses of $26 million, $6 million and $2 million, respectively, and a decrease of $13 million in Adjusted EBITDA related to unconsolidated affiliates;
- an increase of $4 million in transportation fees, excluding the incremental transportation fees related to the RIGS consolidation discussed above, primarily due to higher demand on existing pipelines; and

Table of Contents

- an increase of $3 million in realized storage margin primarily due to higher realized derivative gains; partially offset by
- a decrease of $2 million in retained fuel revenues as a result of lower natural gas pricing.

Segment Adjusted EBITDA. For the six months ended June 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $105 million in realized natural gas sales and other due to higher realized gains from pipeline optimization activity; and
- a net increase of $5 million due to the consolidation of RIGS beginning in April 2018, as discussed in “Recent Developments” above, resulting in increases in transportation fees, operating expenses, and selling, general and administrative expenses of $26 million, $6 million and $2 million, respectively, and a decrease of $15 million in Adjusted EBITDA related to unconsolidated affiliates; partially offset by
- a decrease of $21 million in realized storage margin primarily due to an adjustment to the Bammel storage inventory;
- a decrease of $3 million in transportation fees, excluding the incremental transportation fees related to the RIGS consolidation discussed above, primarily due to renegotiated contracts; and
- a decrease of $2 million in retained fuel revenues due to lower natural gas pricing.

Interstate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Natural gas transported (BBtu/d)	8,707	5,299	3,408	8,457	5,476	2,981
Natural gas sold (BBtu/d)	17	17	—	17	17	—
Revenues	$ 328	$ 207	$ 121	$ 644	$ 442	$ 202
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(105)	(67)	(38)	(199)	(141)	(58)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(17)	(7)	(10)	(34)	(19)	(15)
Adjusted EBITDA related to unconsolidated affiliates	123	128	(5)	239	243	(4)
Other	1	1	—	3	2	1
Segment Adjusted EBITDA	$ 330	$ 262	$ 68	$ 653	$ 527	$ 126

Volumes. For the three months ended June 30, 2018 compared to the same period last year, transported volumes reflected an increase of 1,748 BBtu/d as a result of the partial in service of the Rover pipeline; increases of 654 BBtu/d and 425 BBtu/d on the Panhandle and Trunkline pipelines, respectively, due to increased utilization of higher contracted capacity; an increase of 350 BBtu/d on the Tiger pipeline as a result of production increases in the Haynesville Shale and deliveries into intrastate markets; and an increase of 200 BBtu/d on the Transwestern pipeline resulting from favorable opportunities in the midcontinent and Waha areas from the Permian supply basin.

For the six months ended June 30, 2018 compared to the same period last year, transported volumes reflected an increase of 1,610 BBtu/d as a result of the partial in service of the Rover pipeline; increases of 529 BBtu/d and 328 BBtu/d on the Panhandle and Trunkline pipelines, respectively, due to higher demand resulting from colder weather and increased utilization by the Rover pipeline; an increase of 397 BBtu/d on the Tiger pipeline as a result of production increases in the Haynesville Shale and deliveries into intrastate markets; and an increase of 141 BBtu/d on the Transwestern pipeline resulting from favorable market opportunities in the midcontinent and Waha areas from the Permian supply basin.

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

-

an increase of $68 million from the partial in service of the Rover pipeline with increases of $105 million in revenues, $30 million in operating expenses and $7 million in selling, general and administrative expenses; and

Table of Contents

- an aggregate increase of $19 million in revenues, excluding the incremental revenue related to the Rover pipeline in service discussed above, primarily due to capacity sold at higher rates on the Transwestern and Panhandle pipelines, partially offset by $3 million of lower revenues on the Tiger pipeline due to a customer contract restructuring; partially offset by
- an increase of $8 million in operating expenses, excluding the incremental expenses related to the Rover pipeline in service discussed above, primarily due to higher maintenance project costs;
- an increase of $3 million in selling, general and administrative expenses, excluding the incremental expenses related to the Rover pipeline in service discussed above, primarily due to a reimbursement of legal fees and a franchise tax settlement received in 2017; and
- a decrease of $5 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to lower sales of short-term firm capacity on Citrus.

Segment Adjusted EBITDA. For the six months ended June 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- An increase of $117 million from the partial in service of the Rover pipeline with increases of $187 million in revenues, $56 million in operating expenses and $14 million in selling, general and administrative expenses; and
- an aggregate increase of $21 million in revenues, excluding the incremental revenues related to the Rover pipeline in service discussed above, primarily due to capacity sold at higher rates on the Transwestern and Panhandle pipelines, partially offset by $6 million of lower revenues on the Tiger pipeline due to a customer contract restructuring; partially offset by
- an increase of $2 million in operating expenses, excluding the incremental expenses related to the Rover pipeline in service discussed above, primarily due to higher maintenance project costs; and
- a decrease of $4 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to lower sales of short term firm capacity on Citrus.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Gathered volumes (BBtu/d)	11,576	10,961	615	11,442	10,599	843
NGLs produced (MBbls/d)	513	474	39	508	459	49
Equity NGLs (MBbls/d)	31	28	3	30	27	3
Revenues	$1,874	$1,615	$ 259	$3,488	$3,252	$ 236
Cost of products sold	1,281	1,044	237	2,342	2,168	174
Segment margin	593	571	22	1,146	1,084	62
Unrealized gains on commodity risk management activities	—	(3)	3	—	(19)	19
Operating expenses, excluding non-cash compensation expense	(169)	(152)	(17)	(333)	(313)	(20)
Selling, general and administrative expenses, excluding non-cash compensation expense	(20)	(11)	(9)	(40)	(34)	(6)
Adjusted EBITDA related to unconsolidated affiliates	9	7	2	16	14	2
Other	1	—	1	2	—	2
Segment Adjusted EBITDA	$414	$412	$ 2	$791	$732	$ 59

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

Table of Contents

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Gathering and processing fee-based revenues	$453	$436	$ 17	$874	$844	$ 30
Non-fee-based contracts and processing (excluding unrealized gains and losses)	140	132	8	272	221	51
Unrealized gains on commodity risk management activities	—	3	(3)	—	19	(19)
Total segment margin	$593	$571	$ 22	$1,146	$1,084	$ 62

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

- an increase of $17 million in fee-based margin due to growth in the Permian and Northeast regions, offset by declines in the South Texas, North Texas and midcontinent/Panhandle regions;
- an increase of $6 million in non-fee-based margin primarily due to higher crude oil and NGL prices;
- an increase of $2 million in non-fee-based margin due to increased throughput volume in the Permian region; and
- an increase of $2 million in Adjusted EBITDA related to unconsolidated affiliates due to higher earnings from our Aqua, Mi Vida and Ranch joint ventures; partially offset by
- an increase of $17 million in operating expenses primarily due to increases of $6 million in outside services, $5 million in materials, $2 million in employee costs and $2 million in ad valorem taxes; and
- an increase of $9 million in selling, general and administrative expenses primarily due to a favorable impact recorded in the prior period from the adjustment of certain reserves in connection with contingent matters.

Segment Adjusted EBITDA. For the six months ended June 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $27 million in non-fee-based margin primarily due to higher crude oil and NGL prices;
- an increase of $24 million in non-fee-based margin due to increased throughput volume in the Permian region;
- an increase of $30 million in fee-based margin due to growth in the Permian and Northeast regions, offset by declines in the South Texas, North Texas and midcontinent/Panhandle regions; and
- an increase of $2 million in Adjusted EBITDA related to unconsolidated affiliates due to higher earnings from our Aqua, Mi Vida and Ranch joint ventures; partially offset by
- an increase of $20 million in operating expenses due to increases of $8 million in outside services, $5 million in materials, $4 million in employee costs and $3 million in ad valorem taxes; and
- an increase of $6 million in selling, general and administrative expenses primarily due to a favorable impact recorded in the prior period from the adjustment of certain reserves in connection with contingent matters.

Table of Contents

NGL and Refined Products Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
NGL transportation volumes (MBbls/d)	967	835	132	951	823	128
Refined products transportation volumes (MBbls/d)	637	643	(6)	629	633	(4)
NGL and refined products terminal volumes (MBbls/d)	789	767	22	746	779	(33)
NGL fractionation volumes (MBbls/d)	473	431	42	473	430	43
Revenues	$2,568	$1,779	$789	$5,114	$4,045	$1,069
Cost of products sold	1,981	1,263	718	3,927	2,970	957
Segment margin	587	516	71	1,187	1,075	112
Unrealized (gains) losses on commodity risk management activities	13	(4)	17	—	(54)	54
Operating expenses, excluding non-cash compensation expense	(141)	(125)	(16)	(280)	(252)	(28)
Selling, general and administrative expenses, excluding non-cash compensation expense	(17)	(17)	—	(35)	(36)	1
Adjusted EBITDA related to unconsolidated affiliates	19	18	1	40	35	5
Other	—	—	—	—	1	(1)
Segment Adjusted EBITDA	$461	$388	$73	$912	$769	$143

Volumes. For the three and six months ended June 30, 2018 compared to the same periods last year, NGL transportation volumes increased primarily from the Permian region resulting from a ramp up in production from existing customers.

Refined products transportation volumes decreased slightly for the three and six months ended June 30, 2018 compared to the same periods last year primarily due to lower throughput volumes from the Midwest region due to end user operational issues, partially offset by increased throughput volumes from the Southwest region due to increased demand.

Compared to the same periods last year, NGL and refined products terminal volumes increased for the three months ended June 30, 2018 but decreased for the six months ended June 30, 2018. The increase for the three months ended June 30, 2018 compared to the same period last year was primarily due to more volumes loaded at our Nederland terminal as propane export demand increased, as well as higher refined products throughput volumes at our Eagle Point terminal, partially offset by lower throughput volumes at our Marcus Hook Industrial Complex primarily due to Mariner East 1 system downtime during the second quarter of 2018. For the six months ended June 30, 2018 compared to the same period in the prior year, the decrease was primarily due to lower throughput volumes at our Marcus Hook Industrial Complex due to Mariner East 1 system downtime, lower refined product throughput volumes at our Eagle Point terminal and lower volumes at our refined products marketing terminals.

Average fractionated volumes at our Mont Belvieu, Texas fractionation facility increased for the three and six months ended June 30, 2018 compared to the same periods last year primarily due to increased volumes from Permian producers.

Table of Contents

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Fractionators and Refinery services margin	$128	$117	$ 11	$262	$237	$ 25
Transportation margin	290	241	49	556	474	82
Storage margin	48	53	(5)	104	110	(6)
Terminal Services margin	91	81	10	185	168	17
Marketing margin	43	20	23	80	32	48
Unrealized gains (losses) on commodity risk management activities	(13)	4	(17)	—	54	(54)
Total segment margin	$587	$516	$ 71	$1,187	$1,075	$ 112

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

- an increase of $49 million in transportation margin due to a $43 million increase resulting from increased producer volumes from the Permian region on our Texas NGL pipelines, an $11 million increase resulting from a reclassification between our transportation and fractionation margins, a $4 million increase due to higher throughput on Mariner West and a $2 million increase on Mariner South primarily due to system downtime in the prior period. These increases were partially offset by an $11 million decrease resulting from lower throughput on Mariner East 1 due to system downtime in the second quarter of 2018;
- an increase of $23 million in marketing margin (excluding a net change of $17 million in unrealized gains and losses) due to gains of $10 million from our butane blending operations, a $9 million increase from sales of domestic propane and other products at our Marcus Hook Industrial Complex and a $4 million increase from optimizing sales of purity product from our Mont Belvieu fractionators;
- an increase of $11 million in fractionation and refinery services margin due to a $14 million increase resulting from higher NGL volumes from the Permian region feeding our Mont Belvieu fractionation facility, a $6 million increase from blending gains as a result of improved market pricing and a $2 million increase from Mariner South as more cargoes were loaded at Mariner South. These increases were partially offset by an $11 million decrease resulting from a reclassification between our transportation and fractionation margins; and
- an increase of $10 million in terminal services margin due to a $7 million increase resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018 and a $5 million increase at our Nederland terminal due to increased demand for propane exports. These increases were partially offset by a $2 million decrease due to the effect of Mariner East pipeline system downtime on our Marcus Hook Industrial Complex;

partially offset by

- an increase of $16 million in operating expenses primarily due to a $7 million increase resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018, a $4 million increase in utilities and ad valorem taxes on the fractionators, and a $3 million increase in overhead costs; and
- a decrease of $5 million in storage margin primarily due to the expiration and amendments to various NGL and refined products storage contracts.

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

- an increase of $82 million in transportation margin due to $78 million from increased producer volumes from the Permian region on our Texas NGL pipelines, an $11 million increase due to higher throughput on Mariner

West driven by end user facility constraints in the prior period, an $11 million increase resulting from a reclassification between our transportation and fractionation margins, a $3 million increase on Mariner South primarily due to system downtime in the prior period and a $4 million increase from higher deficiency fees. These increases were partially offset by a $17 million decrease resulting from lower throughput on Mariner East 1 due to system downtime in 2018, and $8 million due to lower transport revenue from the Eagle Ford and Southeast Texas regions.

- an increase of $48 million in marketing margin (excluding a net change of $54 million in unrealized gains and losses) due to an $18 million increase from our butane blending operations, a $17 million increase from sales of domestic propane and other products at our Marcus Hook Industrial Complex and a $13 million increase from optimizing sales of purity product from our Mont Belvieu fractionators;
- an increase of $25 million in fractionation and refinery services margin due to a $23 million increase resulting from higher NGL volumes from the Permian region feeding our Mont Belvieu fractionation facility, a $9 million increase from blending gains as a result of improved market pricing and a $4 million increase as we loaded more cargoes at our Mariner South export facility. These increases were partially offset by an $11 million decrease resulting from a reclassification between our transportation and fractionation margins;
- an increase of $17 million in terminal services margin due to a $18 million increase resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018 and a $6 million increase at our Nederland terminal due to increased demand for propane exports. These increases were partially offset by a $4 million decrease due to the effect of Mariner East pipeline system downtime on our Marcus Hook Industrial Complex and a $3 million decrease from our marketing terminal volumes primarily due to the sale of one of our terminals in April 2017; and
- an increase of $5 million in Adjusted EBITDA related to unconsolidated affiliates due to improved contributions from our unconsolidated refined products joint venture interests; partially offset by
- an increase of $28 million in operating expenses due to a $18 million increase resulting from a change in the classification of certain customer reimbursements previously recorded as a reduction to operating expenses that are now classified as revenue following the adoption of ASC 606 on January 1, 2018, a $6 million increases in certain allocated overhead and a $4 million increase in utilities and ad valorem taxes on the fractionators; and
- a decrease of $6 million in storage margin due to a $8 million decrease from the expiration and amendments to various NGL and refined products storage contracts and a $4 million decrease from the expiration of a fixed fee transport agreement in 2017. These increases were partially offset by a $6 million increase from throughput fees collected at our Mont Belvieu storage terminal and increased demand on the Explorer Pipeline.

Crude Oil Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Crude transportation volumes (MBbls/d)	4,242	3,452	790	4,036	3,248	788
Crude terminals volumes (MBbls/d)	2,103	1,950	153	2,022	1,864	158
Revenues	$4,803	$2,465	$2,338	$8,548	$5,040	$3,508
Cost of products sold	4,361	2,091	2,270	7,538	4,394	3,144
Segment margin	442	374	68	1,010	646	364
Unrealized losses (gains) on commodity risk management activities	262	(2)	264	305	(2)	307
Operating expenses, excluding non-cash compensation expense	(144)	(114)	(30)	(271)	(186)	(85)
Selling, general and administrative expenses, excluding non-cash compensation expense	(20)	(32)	12	(42)	(49)	7
Adjusted EBITDA related to unconsolidated affiliates	8	2	6	10	6	4
Segment Adjusted EBITDA	$548	$228	$320	$1,012	$415	$597

Volumes. For the three and six months ended June 30, 2018 crude transportation volumes increased due to placing the Bakken pipeline in service in June 2017 as well as increased volumes on existing pipelines due to increased production in West Texas. For the three and six months ended June 30, 2018 crude terminal volumes increased due to increased volumes delivered to our Nederland crude terminal from the Bakken pipeline and from increased West

Texas production.

Table of Contents

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

- an increase of $332 million in segment margin (excluding unrealized losses on commodity risk management activities) due to a $193 million increase resulting primarily from placing our Bakken pipeline in service in the second quarter of 2017 as well as a $27 million increase resulting from increased throughput, primarily from Permian producers, on existing pipeline assets; a $100 million increase (excluding a net change of $264 million in unrealized gains and losses) from our crude oil acquisition and marketing business primarily resulting from more favorable market price differentials between the West Texas and Gulf Coast markets; and a $9 million increase in terminal fees primarily from ship loading fees at our Nederland facility as a result of increased exports;
- a decrease of $12 million in selling, general and administrative expenses primarily due to higher professional fees recorded in the prior period; and
- an increase of $6 million in Adjusted EBITDA related to unconsolidated affiliates due to a new contract at one of our joint ventures; partially offset by
- an increase of $30 million in operating expenses due to a $13 million increase primarily resulting from placing our Bakken pipeline in service in the second quarter of 2017; a $3 million increase resulting from the addition of certain joint venture transportation assets in the second quarter of 2017; and a $14 million increase from existing transportation assets due to increases of $7 million in utilities, $5 million in expense projects, $5 million in ad valorem taxes and $5 million in management fees, partially offset by decreases in environmental fees of $5 million and capacity leases of $3 million.

Segment Adjusted EBITDA. For the six months ended June 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $671 million in segment margin (excluding unrealized losses on commodity risk management activities) due to a $417 million increase resulting primarily from placing our Bakken pipeline in service in the second quarter of 2017; a $50 million increase resulting from increased throughput, primarily from Permian producers, on existing pipeline assets; a $188 million increase (excluding a net change of $307 million in unrealized gains and losses) from our crude oil acquisition and marketing business primarily resulting from more favorable market price differentials between the West Texas and Gulf Coast markets; and a $16 million increase primarily from our Nederland facility due to higher ship loading fees as a result of increased exports;
- a decrease of $7 million in selling, general and administrative expenses due to a $13 million decrease in professional fees, partially offset by an increase of $6 million related to Bakken insurance and management fees; and
- an increase of $4 million in Adjusted EBITDA related to unconsolidated affiliates due to a new contract at one of our joint ventures; partially offset by
- an increase of $85 million in operating expenses due to a $39 million increase primarily resulting from placing our Bakken pipeline in service in the second quarter of 2017; a $15 million increase resulting from the addition of certain joint venture transportation assets in the second quarter of 2017; and a $31 million increase from existing transportation assets due to increases of $10 million in ad valorem taxes, $9 million in management fees, $8 million in utilities, $5 million in expense projects and $5 million in freight, partially offset by decreases in environmental fees of $5 million and capacity leases of $1 million.

Table of Contents

All Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Revenues	$502	$870	$(368)	$1,073	$1,640	$(567)
Cost of products sold	445	794	(349)	921	1,462	(541)
Segment margin	57	76	(19)	152	178	(26)
Unrealized (gains) losses on commodity risk management activities	(2)	(4)	2	2	(17)	19
Operating expenses, excluding non-cash compensation expense	(10)	(31)	21	(41)	(52)	11
Selling, general and administrative expenses, excluding non-cash compensation expense	(19)	(27)	8	(37)	(48)	11
Adjusted EBITDA related to unconsolidated affiliates	62	76	(14)	88	156	(68)
Other and eliminations	2	17	(15)	—	13	(13)
Segment Adjusted EBITDA	$90	$107	$(17)	$164	$230	$(66)

Amounts reflected in our all other segment primarily include:

- our equity method investment in limited partnership units of Sunoco LP consisting of 26.2 million and 43.5 million Sunoco LP common units, representing 31.8% and 43.7% of Sunoco LP's total outstanding common units as of June 30, 2018 and June 30, 2017, respectively. In February 2018, after the record date for Sunoco LP's fourth quarter 2017 cash distributions, Sunoco LP repurchased 17,286,859 Sunoco LP common units owned by ETP for aggregate cash consideration of approximately $540 million;
- our natural gas marketing and compression operations. Subsequent to our contribution of CDM to USAC in April 2018, our all other segment includes our equity method investment in USAC consisting of 19.2 million USAC common units and 6.4 million USAC Class B Units, together representing 26.6% of the limited partner interests;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in coal handling facilities.

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

- a decrease of $44 million in Adjusted EBITDA related to unconsolidated affiliates from our investment in Sunoco LP resulting from the Partnership's lower ownership in Sunoco LP and lower operating results of Sunoco LP due to the sale of the majority of its retail assets in January 2018; and
- a decrease of $12 million due to the contribution of CDM to USAC in April 2018, which decrease reflects the impact of deconsolidating CDM, partially offset by an increase in Adjusted EBITDA related to unconsolidated affiliates due to the equity method investment in USAC held by ETP subsequent to the CDM Contribution; partially offset by
- a decrease of $14 million in merger and acquisition expenses related to the Sunoco Logistics merger in 2017, partially offset by the CDM Contribution in 2018;
- an increase of $12 million in Adjusted EBITDA related to unconsolidated affiliates from our investment in PES;
- an increase of $6 million from gains in power trading activities; and
- an increase of $2 million in margin due to the expiration of a capacity contract commitment.

Segment Adjusted EBITDA. For the six months ended June 30, 2018 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment decreased due to the net impacts of the following:

- a decrease of $69 million in Adjusted EBITDA related to unconsolidated affiliates from our investment in Sunoco LP resulting from the Partnership's lower ownership in Sunoco LP and lower operating results of Sunoco LP due to the sale of the majority of its retail assets in January 2018;

Table of Contents

- a decrease of $18 million in Adjusted EBITDA related to unconsolidated affiliates primarily from our investment in PES; and
- a decrease of $9 million due to the contribution of CDM to USAC in April 2018, which decrease reflects the impact of deconsolidating CDM, partially offset by an increase in Adjusted EBITDA related to unconsolidated affiliates due to the equity method investment in USAC held by ETP subsequent to the CDM Contribution; partially offset by
- a decrease of $17 million in merger and acquisition expenses related to the Sunoco Logistics merger in 2017, partially offset by the CDM Contribution in 2018;
- an increase of $8 million from commodity trading activities; and
- an increase of $5 million in margin from the expiration of a capacity contract commitment.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

We currently expect capital expenditures in 2018 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$275	$300	$30	$35
Interstate transportation and storage [1]	500	550	115	120
Midstream	850	875	120	130
NGL and refined products transportation and services	2,350	2,500	60	70
Crude oil transportation and services [1]	450	475	90	100
All other (including eliminations)	75	100	60	65
Total capital expenditures	$4,500	$4,800	$475	$520

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

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

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

Cash Flows

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

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and net changes in operating assets and liabilities (net of effects of acquisitions and deconsolidations). Non-cash items include recurring non-cash expenses, such as depreciation, depletion and amortization expense and non-cash compensation expense. The increase in depreciation, depletion and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for

60

Table of Contents

such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of derivative assets and liabilities, the timing of accounts receivable collection, the timing of payments on accounts payable, the timing of purchase and sales of inventories and the timing of advances and deposits received from customers.

Six months ended June 30, 2018 compared to six months ended June 30, 2017. Cash provided by operating activities during 2018 was $2.95 billion compared to $1.65 billion for 2017 and net income was $1.48 billion and $689 million for 2018 and 2017, respectively. The difference between net income and cash provided by operating activities for the six months ended June 30, 2018 primarily consisted of net changes in operating assets and liabilities (net of effects of acquisitions and deconsolidations) of $229 million and other non-cash items totaling $1.04 billion.

The non-cash activity in 2018 and 2017 consisted primarily of depreciation, depletion and amortization of $1.19 billion and $1.12 billion, respectively, and non-cash compensation expense of $41 million and $38 million, respectively. Unconsolidated affiliate activity in 2018 and 2017 consisted of equity in earnings of $34 million and $12 million, respectively, and distributions received of $215 million and $197 million, respectively. Non-cash activity in 2018 also included a gain on the sale of Sunoco LP units of $172 million, a loss on the deconsolidation of CDM of $86 million and an increase in deferred income taxes of $52 million. Non-cash activity in 2017 also included an increase in deferred income taxes of $121 million.

Cash paid for interest, net of interest capitalized, was $690 million and $673 million for the six months ended June 30, 2018 and 2017, respectively.

Capitalized interest was $160 million and $124 million for the six months ended June 30, 2018 and 2017, respectively.

Investing Activities

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

Six months ended June 30, 2018 compared to six months ended June 30, 2017. Cash used in investing activities during 2018 was $1.59 billion compared to $1.49 billion in 2017. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2018 were $3.35 billion compared to $2.83 billion for 2017. Additional detail related to our capital expenditures is provided in the table below. During 2018, we received $1.23 billion in cash related to the CDM Contribution and $540 million in cash related to the Sunoco LP common unit repurchase. During 2017, we received $2.00 billion in cash related to the Bakken equity sale to MarEn Bakken Company, paid $280 million in cash for the acquisition of PennTex noncontrolling interest and paid $261 million in cash for all other acquisitions.

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

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$195	$ 21	$216
Interstate transportation and storage	351	37	388