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

FORM 10-Q

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

For the quarterly period ended September 30, 2021

or

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

Commission file number 1-32740

ENERGY TRANSFER LP
(Exact name of registrant as specified in its charter)

Delaware	**30-0108820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	**ET**	**New York Stock Exchange**
7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETprC**	**New York Stock Exchange**
7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETprD**	**New York Stock Exchange**
7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETprE**	**New York Stock Exchange**

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

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

At October 29, 2021, the registrant had 2,705,855,172 Common Units outstanding.

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ENERGY TRANSFER LP AND SUBSIDIARIES
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Definitions

References to the “Partnership” or “ET” refer to Energy Transfer LP. In addition, the following is a list of certain acronyms and terms used throughout this document:

/d	per day
AOCI	accumulated other comprehensive income (loss)
BBtu	billion British thermal units
Citrus	Citrus, LLC, a 50/50 joint venture which owns FGT
Dakota Access	Dakota Access, LLC
Enable	Enable Midstream Partners, LP, a Delaware limited partnership
Energy Transfer Canada	Energy Transfer Canada ULC, a less than wholly-owned subsidiary of ET
Energy Transfer R&M	Energy Transfer (R&M), LLC (formerly Sunoco (R&M), LLC)
ET Preferred Units	Collectively, the Series A Preferred Units, Series B Preferred Units, Series C Preferred Units, Series D Preferred Units, Series E Preferred Units, Series F Preferred Units and Series G Preferred Units (all originally issued by ETO and exchanged for preferred units issued by ET on April 1, 2021), as well as the Series H Preferred Units issued by ET in June 2021
ETC Tiger	ETC Tiger Pipeline, LLC, a wholly-owned subsidiary of ET, which owns the Tiger Pipeline
ETO	Energy Transfer Operating, L.P.
Exchange Act	Securities Exchange Act of 1934
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company, LLC, a wholly-owned subsidiary of Citrus
GAAP	accounting principles generally accepted in the United States of America
HFOTCO	Houston Fuel Oil Terminal Company, a wholly-owned subsidiary of ET, which owns the Houston Terminal
LE GP	LE GP, LLC, the general partner of ET
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, a wholly-owned subsidiary of ET
Regency	Regency Energy Partners LP
Rover	Rover Pipeline LLC
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
Series E Preferred Units	7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series F Preferred Units	6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series G Preferred Units	7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series H Preferred Units	6.500% Series H Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Sunoco Logistics Operations	Sunoco Logistics Partners Operations L.P, a wholly-owned subsidiary of ET
Transwestern	Transwestern Pipeline Company, LLC, a wholly-owned subsidiary of ET
Trunkline	Trunkline Gas Company, LLC, a wholly-owned subsidiary of Panhandle
USAC	USA Compression Partners, LP, a subsidiary of ET
USAC Preferred Units	USAC Series A preferred units
White Cliffs	White Cliffs Pipeline, L.L.C.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(unaudited)

	September 30, 2021	December 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 313	$ 367
Accounts receivable, net	6,437	3,875
Accounts receivable from related companies	63	79
Inventories	1,811	1,739
Income taxes receivable	42	35
Derivative assets	57	9
Other current assets	326	213
Total current assets	9,049	6,317
Property, plant and equipment	95,775	94,115
Accumulated depreciation and depletion	(21,504)	(19,008)
	74,271	75,107
Investments in unconsolidated affiliates	2,958	3,060
Lease right-of-use assets, net	829	866
Other non-current assets, net	1,722	1,657
Intangible assets, net	5,474	5,746
Goodwill	2,395	2,391
Total assets	$ 96,698	$ 95,144

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Dollars in million)
(unaudited)

	September 30, 2021	December 31, 2020
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 5,707	$ 2,809
Accounts payable to related companies	—	27
Derivative liabilities	205	238
Operating lease current liabilities	46	53
Accrued and other current liabilities	3,198	2,775
Current maturities of long-term debt	678	21
Total current liabilities	9,834	5,923
Long-term debt, less current maturities	44,793	51,417
Non-current derivative liabilities	187	237
Non-current operating lease liabilities	799	837
Deferred income taxes	3,683	3,428
Other non-current liabilities	1,270	1,152
Commitments and contingencies		
Redeemable noncontrolling interests	783	762
Equity:		
Limited Partners:		
Preferred Unitholders	5,671	—
Common Unitholders	21,726	18,531
General Partner	(5)	(8)
Accumulated other comprehensive income	19	6
Total partners’ capital	27,411	18,529
Noncontrolling interests	7,938	12,859
Total equity	35,349	31,388
Total liabilities and equity	$ 96,698	$ 95,144

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except per unit data)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
REVENUES:				
Refined product sales	$ 4,810	$ 2,720	$ 12,737	$ 7,952
Crude sales	4,021	2,298	10,920	7,170
NGL sales	4,005	1,808	10,275	4,751
Gathering, transportation and other fees	2,276	2,283	6,797	6,805
Natural gas sales	1,376	681	7,507	1,783
Other	176	165	524	459
Total revenues	16,664	9,955	48,760	28,920
COSTS AND EXPENSES:				
Cost of products sold	13,188	6,376	35,641	18,784
Operating expenses	898	773	2,585	2,422
Depreciation, depletion and amortization	943	912	2,837	2,715
Selling, general and administrative	198	176	583	555
Impairment losses	—	1,474	11	2,803
Total costs and expenses	15,227	9,711	41,657	27,279
OPERATING INCOME	1,437	244	7,103	1,641
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(558)	(569)	(1,713)	(1,750)
Equity in earnings (losses) of unconsolidated affiliates	71	(32)	191	46
Impairment of investment in an unconsolidated affiliate	—	(129)	—	(129)
Losses on extinguishments of debt	—	—	(8)	(62)
Gains (losses) on interest rate derivatives	1	55	72	(277)
Other, net	33	71	45	6
INCOME (LOSS) BEFORE INCOME TAX EXPENSE	984	(360)	5,690	(525)
Income tax expense	77	41	234	168
NET INCOME (LOSS)	907	(401)	5,456	(693)
Less: Net income attributable to noncontrolling interests	260	242	870	427
Less: Net income attributable to redeemable noncontrolling interests	12	12	37	37
NET INCOME (LOSS) ATTRIBUTABLE TO PARTNERS	635	(655)	4,549	(1,157)
General Partner’s interest in net income (loss)	1	—	5	(1)
Preferred Unitholders’ interest in net income	99	—	185	—
Limited Partners’ interest in net income (loss)	$ 535	$ (655)	$ 4,359	$ (1,156)
NET INCOME (LOSS) PER LIMITED PARTNER UNIT:				
Basic	$ 0.20	$ (0.24)	$ 1.61	$ (0.43)
Diluted	$ 0.20	$ (0.24)	$ 1.60	$ (0.43)

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net income (loss)	$ 907	$ (401)	$ 5,456	$ (693)
Other comprehensive income (loss), net of tax:				
Change in value of available-for-sale securities	2	3	5	3
Actuarial gain related to pension and other postretirement benefit plans	1	4	6	15
Foreign currency translation adjustments	(21)	18	3	(16)
Change in other comprehensive income (loss) from unconsolidated affiliates	1	1	1	(15)
	(17)	26	15	(13)
Comprehensive income (loss)	890	(375)	5,471	(706)
Less: Comprehensive income attributable to noncontrolling interests	250	251	872	407
Less: Comprehensive income attributable to redeemable noncontrolling interests	12	12	37	37
Comprehensive income (loss) attributable to partners	$ 628	$ (638)	$ 4,562	$ (1,150)

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)
(unaudited)

	Common Unitholders	Preferred Unitholders	General Partner	AOCI	Noncontrolling Interests	Total
Balance, December 31, 2020	$ 18,531	$ —	$ (8)	$ 6	$ 12,859	$ 31,388
Distributions to partners	(406)	—	—	—	—	(406)
Distributions to noncontrolling interests	—	—	—	—	(406)	(406)
Capital contributions from noncontrolling interests	—	—	—	—	20	20
Other comprehensive income, net of tax	—	—	—	2	6	8
Other, net	18	—	—	—	3	21
Net income, excluding amounts attributable to redeemable noncontrolling interests	3,285	—	3	—	341	3,629
Balance, March 31, 2021	21,428	—	(5)	8	12,823	34,254
Preferred units converted in Rollup Mergers	—	4,768	—	—	(4,768)	—
Distributions to partners	(403)	(88)	(1)	—	—	(492)
Distributions to noncontrolling interests	—	—	—	—	(354)	(354)
Units issued	—	889	—	—	—	889
Capital contributions from noncontrolling interests	—	—	—	—	43	43
Other comprehensive income, net of tax	—	—	—	18	6	24
Other, net	15	(1)	—	—	2	16
Net income, excluding amounts attributable to redeemable noncontrolling interests	539	86	1	—	269	895
Balance, June 30, 2021	21,579	5,654	(5)	26	8,021	35,275
Distributions to partners	(404)	(80)	(1)	—	—	(485)
Distributions to noncontrolling interests		—	—	—	(389)	(389)
Capital contributions from noncontrolling interests	—	—	—	—	51	51
Other comprehensive loss, net of tax	—	—	—	(7)	(10)	(17)
Other, net	16	(2)	—	—	5	19
Net income, excluding amounts attributable to redeemable noncontrolling interests	535	99	1	—	260	895
Balance, September 30, 2021	$ 21,726	$ 5,671	$ (5)	$ 19	$ 7,938	$ 35,349

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY (continued)
(Dollars in millions)
(unaudited)

	Common Unitholders	General Partner	AOCI	Noncontrolling Interests	Total
Balance, December 31, 2019	$ 21,935	$ (4)	$ (11)	$ 12,018	$ 33,938
Distributions to partners	(1,591)	(1)	—	—	(1,592)
Distributions to noncontrolling interests	—	—	—	(444)	(444)
Subsidiary units issued	—	—	—	1,580	1,580
Capital contributions from noncontrolling interests	—	—	—	95	95
Other comprehensive loss, net of tax	—	—	(48)	(38)	(86)
Other, net	22	—	—	(7)	15
Net loss, excluding amounts attributable to redeemable noncontrolling interests	(854)	(1)	—	(121)	(976)
Balance, March 31, 2020	19,512	(6)	(59)	13,083	32,530
Distributions to partners	9	(1)	—	—	8
Distributions to noncontrolling interests	—	—	—	(408)	(408)
Capital contributions from noncontrolling interests	—	—	—	83	83
Other comprehensive income, net of tax	—	—	38	9	47
Other, net	(31)	—	—	4	(27)
Net income, excluding amounts attributable to redeemable noncontrolling interests	353	—	—	306	659
Balance, June 30, 2020	19,843	(7)	(21)	13,077	32,892
Distributions to partners	(812)	(1)	—	—	(813)
Distributions to noncontrolling interests	—	—	—	(430)	(430)
Capital contributions from noncontrolling interests	—	—	—	25	25
Other comprehensive income, net of tax	—	—	17	9	26
Other, net	47	—	—	(43)	4
Net income (loss), excluding amounts attributable to redeemable noncontrolling interests	(655)	—	—	242	(413)
Balance, September 30, 2020	$ 18,423	$ (8)	$ (4)	$ 12,880	$ 31,291

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

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)
(unaudited)

	Nine Months Ended September 30,	
	2021	2020
OPERATING ACTIVITIES:		
Net income (loss)	$ 5,456	$ (693)
Reconciliation of net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	2,837	2,715
Deferred income taxes	199	159
Inventory valuation adjustments	(168)	126
Non-cash compensation expense	81	93
Impairment losses	11	2,803
Impairment of investment in an unconsolidated affiliate	—	129
Losses on extinguishments of debt	8	62
Distributions on unvested awards	(19)	(33)
Equity in earnings of unconsolidated affiliates	(191)	(46)
Distributions from unconsolidated affiliates	226	176
Other non-cash	13	(130)
Net change in operating assets and liabilities, net of effects of acquisitions	970	94
Net cash provided by operating activities	9,423	5,455
INVESTING ACTIVITIES:		
Capital expenditures, excluding allowance for equity funds used during construction	(2,046)	(4,030)
Contributions in aid of construction costs	29	61
Contributions to unconsolidated affiliates	(4)	(37)
Distributions from unconsolidated affiliates in excess of cumulative earnings	76	144
Proceeds from sales of other assets	38	10
Other	—	(9)
Net cash used in investing activities	(1,907)	(3,861)
FINANCING ACTIVITIES:		
Proceeds from borrowings	11,839	20,651
Repayments of debt	(17,836)	(20,293)
Preferred Units issued for cash	889	—
Subsidiary units issued for cash	—	1,580
Capital contributions from noncontrolling interests	114	203
Distributions to partners	(1,383)	(2,397)
Distributions to noncontrolling interests	(1,149)	(1,282)
Distributions to redeemable noncontrolling interest	(37)	(37)
Debt issuance costs	(3)	(53)
Other, net	(4)	18
Net cash used in financing activities	(7,570)	(1,610)
Decrease in cash and cash equivalents	(54)	(16)
Cash and cash equivalents, beginning of period	367	291
Cash and cash equivalents, end of period	$ 313	$ 275

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

ENERGY TRANSFER LP 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

The consolidated financial statements presented herein contain the results of Energy Transfer LP and its subsidiaries (the "Partnership," "we," "us," "our" or "ET").

On April 1, 2021, ET, ETO and certain of ETO's subsidiaries consummated several internal reorganization transactions (the "Rollup Mergers"). In connection with the Rollup Mergers, Sunoco Logistics Operations merged with and into ETO, with ETO surviving, and immediately thereafter, ETO merged with and into ET, with ET surviving. The impacts of the Rollup Mergers also included the following:

- All of ETO's long-term debt was assumed by ET, as more fully described in Note 7.
- Each issued and outstanding ETO preferred unit was converted into the right to receive one newly created ET preferred unit. A description of the ET Preferred Units is included in Note 9.
- Each of ETO's issued and outstanding Class K, Class L, Class M and Class N units, all of which were held by ETP Holdco Corporation, a wholly-owned subsidiary of ETO, were converted into an aggregate 675,625,000 newly created Class B Units representing limited partner interests in ET.

Basis of Presentation

The unaudited financial information included in this Form 10-Q has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2020, filed with the SEC on February 19, 2021. 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 consolidated financial statements of the Partnership presented herein include the results of operations of our controlled subsidiaries, including Sunoco LP and USAC.

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

Certain prior period amounts have been reclassified to conform to the current period presentation. These reclassifications had no impact on net income or total equity.

Use of Estimates

The unaudited consolidated financial statements have been prepared in conformity with GAAP, which requires the use of estimates and assumptions made by management that affect the reported amounts of assets, liabilities, revenues, expenses and the accrual for 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.

2. ACQUISITIONS AND RELATED TRANSACTIONS

Pending Enable Acquisition

On February 16, 2021, the Partnership entered into a definitive merger agreement to acquire Enable. Under the terms of the merger agreement, Enable's common unitholders will receive 0.8595 of an ET common unit in exchange for each Enable common unit. In addition, each outstanding Enable preferred unit will be exchanged for 0.0265 of a Series G Preferred

Unit, and ET will make a $10 million cash payment for Enable's general partner. In May 2021, the Enable common unitholders voted to approve the merger. The transaction is subject to the satisfaction of customary closing conditions, including Hart-Scott-Rodino Act ("HSR") clearance.

The Federal Trade Commission ("FTC") has issued requests for additional information and documentary material (the "Second Request"). The effect of the Second Request is to extend the waiting period imposed by the HSR Act until 30 days after the Partnership and Enable have certified substantial compliance with the Second Request, unless that period is extended voluntarily or terminated sooner by the FTC. We continue to believe that the FTC will grant clearance of the transaction, and we remain fully committed to closing the Enable merger under the terms of the merger agreement. We expect to close the transaction in the fourth quarter of 2021.

3. CASH AND CASH EQUIVALENTS

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value. The Partnership's consolidated balance sheets did not include any material amounts of restricted cash as of September 30, 2021 or December 31, 2020.

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

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

	Nine Months Ended September 30,	
	2021	2020
Accounts receivable	$ (2,562)	$ 1,307
Accounts receivable from related companies	16	(258)
Inventories	96	(298)
Other current assets	(127)	108
Other non-current assets, net	(57)	(26)
Accounts payable	2,917	(1,354)
Accounts payable to related companies	(31)	370
Accrued and other current liabilities	711	127
Other non-current liabilities	138	(5)
Derivative assets and liabilities, net	(131)	123
Net change in operating assets and liabilities, net of effects of acquisitions	$ 970	$ 94

Non-cash activities were as follows:

	Nine Months Ended September 30,	
	2021	2020
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Accrued capital expenditures	$ 385	$ 684
Lease assets obtained in exchange for new lease liabilities	10	130
Distribution reinvestment	24	72

4. INVENTORIES

Inventories consist principally of natural gas held in storage, NGLs and refined products, crude oil and spare parts, all of which are valued at the lower of cost or net realizable value utilizing the weighted-average cost method.

Sunoco LP's fuel inventories are stated at the lower of cost or market using the last-in, first-out ("LIFO") method. As of September 30, 2021 and December 31, 2020, the carrying value of Sunoco LP's fuel inventory included lower of cost or market reserves of $143 million and $311 million, respectively, and the inventory carrying value equaled or exceeded its replacement cost. For the three and nine months ended September 30, 2021 and 2020, the Partnership's consolidated income statements did not include any material amounts of income from the liquidation of LIFO fuel inventory.

	September 30, 2021	December 31, 2020
Natural gas, NGLs and refined products[(1)]	$ 1,238	$ 1,013
Crude oil	160	287
Spare parts and other	413	439
Total inventories	$ 1,811	$ 1,739

(1) Due to changes in fuel prices, Sunoco LP recorded an inventory adjustment on the value of its fuel inventory of $168 million for the nine months ended September 30, 2021.

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

5. FAIR VALUE MEASURES

We have commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the nine months ended September 30, 2021, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the gross fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of September 30, 2021 and December 31, 2020 based on inputs used to derive their fair values:

		Fair Value Measurements at September 30, 2021	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 14	$ 14	$ —
Swing Swaps IFERC	11	11	—
Fixed Swaps/Futures	4	4	—
Forward Physical Contracts	4	—	4
Power:			
Forwards	36	—	36
Futures	4	4	—
Options – Calls	1	1	—
NGLs – Forwards/Swaps	384	384	—
Refined Products – Futures	7	7	—
Crude – Forwards/Swaps	569	569	—
Total commodity derivatives	1,034	994	40
Other non-current assets	37	24	13
Total assets	$ 1,071	$ 1,018	$ 53
Liabilities:			
Interest rate derivatives	$ (376)	$ —	$ (376)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(5)	(5)	—
Swing Swaps IFERC	(7)	(7)	—
Fixed Swaps/Futures	(78)	(78)	—
Forward Physical Contracts	(1)	—	(1)
Power:			
Forwards	(21)	—	(21)
Futures	(11)	(11)	—
Options – Calls	(2)	(2)	—
NGLs – Forwards/Swaps	(364)	(364)	—
Refined Products – Futures	(10)	(10)	—
Crude – Forwards/Swaps	(582)	(582)	—
Total commodity derivatives	(1,081)	(1,059)	(22)
Total liabilities	$ (1,457)	$ (1,059)	$ (398)

		Fair Value Measurements at December 31, 2020	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 12	$ 12	$ —
Swing Swaps IFERC	1	—	1
Fixed Swaps/Futures	13	13	—
Forward Physical Contracts	5	—	5
Power:			
Forwards	4	—	4
Futures	2	2	—
Options – Calls	1	1	—
NGLs – Forwards/Swaps	127	127	—
Refined Products – Futures	3	3	—
Total commodity derivatives	168	158	10
Other non-current assets	34	22	12
Total assets	$ 202	$ 180	$ 22
Liabilities:			
Interest rate derivatives	$ (448)	$ —	$ (448)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(11)	(11)	—
Swing Swaps IFERC	(3)	—	(3)
Fixed Swaps/Futures	(13)	(13)	—
Forward Physical Contracts	(1)	—	(1)
Power:			
Futures	(3)	(3)	—
NGLs – Forwards/Swaps	(227)	(227)	—
Refined Products – Futures	(11)	(11)	—
Total commodity derivatives	(269)	(265)	(4)
Total liabilities	$ (717)	$ (265)	$ (452)

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations as of September 30, 2021 were $51.26 billion and $45.47 billion, respectively. As of December 31, 2020, the aggregate fair value and carrying amount of our consolidated debt obligations were $56.21 billion and $51.44 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the respective debt obligations' observable inputs for similar liabilities.

6. NET INCOME (LOSS) PER LIMITED PARTNER UNIT

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net income (loss)	$ 907	$ (401)	$ 5,456	$ (693)
Less: Net income attributable to noncontrolling interests	260	242	870	427
Less: Net income attributable to redeemable noncontrolling interests	12	12	37	37
Net income (loss), net of noncontrolling interests	635	(655)	4,549	(1,157)
Less: General Partner’s interest in income (loss)	1	—	5	(1)
Less: Preferred Unitholders’ interest in income	99	—	185	—
Income (loss) available to Limited Partners	$ 535	$ (655)	$ 4,359	$ (1,156)
Basic Income (Loss) per Limited Partner Unit:				
Weighted average limited partner units	2,705.2	2,696.6	2,704.0	2,694.4
Basic income (loss) per Limited Partner unit	$ 0.20	$ (0.24)	$ 1.61	$ (0.43)
Diluted Income (Loss) per Limited Partner Unit:				
Income (loss) available to Limited Partners	$ 535	$ (655)	$ 4,359	$ (1,156)
Dilutive effect of equity-based compensation of subsidiaries [(1)]	1	—	2	—
Diluted income (loss) available to Limited Partners	$ 534	$ (655)	$ 4,357	$ (1,156)
Weighted average limited partner units	2,705.2	2,696.6	2,704.0	2,694.4
Dilutive effect of unvested unit awards [(1)]	15.4	—	14.4	—
Weighted average limited partner units, assuming dilutive effect of unvested unit awards	2,720.6	2,696.6	2,718.4	2,694.4
Diluted income (loss) per Limited Partner unit	$ 0.20	$ (0.24)	$ 1.60	$ (0.43)

(1) Dilutive effects are excluded from the calculation for periods where the impact would have been antidilutive.

7. DEBT OBLIGATIONS

In connection with the Rollup Mergers on April 1, 2021, as discussed in Note 1, ET entered into various supplemental indentures and assumed all the obligations of ETO under the respective indentures and credit agreements.

During the first quarter of 2021, ETO redeemed its $600 million aggregate principal amount of 4.40% senior notes due April 1, 2021 and its $800 million aggregate principal amount of 4.65% senior notes due June 1, 2021, using proceeds from the Five-Year Credit Facility.

During the third quarter of 2021, ET issued par call notices to redeem in full its $1.0 billion aggregate principal amount of 5.2% senior notes due February 1, 2022, and $900 million aggregate principal amount of 5.875% senior notes due March 1, 2022. The Partnership expects to redeem both series of senior notes during the fourth quarter of 2021, utilizing proceeds from its Five-Year Credit Facility.

On October 20, 2021, Sunoco LP completed a private offering of $800 million in aggregate principal amount of 4.500% senior notes due 2030 (the “2030 Notes”). Sunoco LP used the proceeds from the private offering to fund a tender offer and repurchase all of its senior notes due 2026.

Credit Facilities and Commercial Paper

Term Loan

As a result of the Rollup Mergers, on April 1, 2021, ET assumed all of ETO’s obligations in respect of its term loan credit agreement (the “Term Loan”) and Sunoco Logistics Operations was released as a guarantor in respect of the Term Loan. The Partnership’s Term Loan provides for a $2.00 billion three-year term loan credit facility.

During the second quarter of 2021, the Partnership repaid $1.5 billion on the Term Loan in part through proceeds from its Series H Preferred Unit issuance. During the third quarter of 2021, the Partnership repaid the remaining $500 million balance and terminated the Term Loan.

Five-Year Credit Facility

As a result of the Rollup Mergers, on April 1, 2021, ET assumed all of ETO's obligations in respect of its revolving credit facility (the "Five-Year Credit Facility") and Sunoco Logistics Operations was released as a guarantor in respect of the Five-Year Credit Facility. The Partnership's Five-Year Credit Facility allows for unsecured borrowings up to $5.00 billion and matures on December 1, 2024. The Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $6.00 billion under certain conditions.

As of September 30, 2021, the Five-Year Credit Facility had $599 million of outstanding borrowings, of which $590 million consisted of commercial paper. The amount available for future borrowings was $4.37 billion, after accounting for outstanding letters of credit in the amount of $31 million. The weighted average interest rate on the total amount outstanding as of September 30, 2021 was 0.43%.

364-Day Facility

As a result of the Rollup Mergers, on April 1, 2021, ET assumed all of ETO's obligations in respect of its 364-day revolving credit facility (the "364-Day Facility") and Sunoco Logistics Operations was released as a guarantor in respect of the 364-Day Facility. The Partnership's 364-Day Facility allows for unsecured borrowings up to $1.00 billion and matures on November 26, 2021. As of September 30, 2021, the 364-Day Facility had no outstanding borrowings.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.50 billion revolving credit facility (the "Sunoco LP Credit Facility"). As of September 30, 2021, the Sunoco LP Credit Facility had $250 million of outstanding borrowings and $6 million in standby letters of credit and matures in July 2023. The amount available for future borrowings at September 30, 2021 was $1.24 billion. The weighted average interest rate on the total amount outstanding as of September 30, 2021 was 2.09%.

USAC Credit Facility

USAC maintains a $1.60 billion revolving credit facility (the "USAC Credit Facility"), which matures on April 2, 2023 and permits up to $400 million of future increases in borrowing capacity. As of September 30, 2021, USAC had $506 million of outstanding borrowings under the USAC Credit Facility. As of September 30, 2021, USAC had $1.09 billion of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $114 million. The weighted average interest rate on the total amount outstanding as of September 30, 2021 was 2.96%.

Energy Transfer Canada Credit Facilities

Energy Transfer Canada is party to a credit agreement providing for a C$350 million (US$276 million at the September 30, 2021 exchange rate) senior secured term loan facility (the "Energy Transfer Canada Term Loan A"), a C$525 million (US$414 million at the September 30, 2021 exchange rate) senior secured revolving credit facility (the "Energy Transfer Canada Revolving Credit Facility"), and a C$300 million (US$237 million at the September 30, 2021 exchange rate) senior secured construction loan facility (the "KAPS Facility"). The Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility mature on February 25, 2024. The KAPS Facility matures on June 13, 2024. Energy Transfer Canada may incur additional term loans and revolving commitments in an aggregate amount not to exceed C$250 million (US$197 million at the September 30, 2021 exchange rate), subject to receiving commitments for such additional term loans or revolving commitments from either new lenders or increased commitments from existing lenders. As of September 30, 2021, the Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility had outstanding borrowings of C$320 million and C$103 million, respectively (US$252 million and US$81 million, respectively, at the September 30, 2021 exchange rate). As of September 30, 2021, the KAPS Facility had outstanding borrowings of C$65 million (US$51 million at the September 30, 2021 exchange rate).

Compliance with our Covenants

We and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of September 30, 2021. For the quarter ended September 30, 2021, our leverage ratio, as calculated pursuant to the covenant related to our revolving credit facility, was 3.15x.

8. REDEEMABLE NONCONTROLLING INTERESTS

Certain redeemable noncontrolling interests in the Partnership's subsidiaries are reflected as mezzanine equity on the consolidated balance sheets. Redeemable noncontrolling interests as of September 30, 2021 included a balance of $477 million related to the USAC Preferred Units described below and a balance of $15 million related to noncontrolling interest holders in one of the Partnership's consolidated subsidiaries that have the option to sell their interests to the Partnership. In addition, as of September 30, 2021, redeemable noncontrolling interests included a balance of $291 million related to Energy Transfer Canada preferred shares.

USAC Preferred Units

As of September 30, 2021, USAC had 500,000 USAC Preferred Units issued and outstanding. The USAC Preferred Units are entitled to receive cumulative quarterly distributions equal to $24.375 per USAC Preferred Unit, subject to increase in certain limited circumstances. The USAC Preferred Units will have a perpetual term, unless converted or redeemed. Certain portions of the USAC Preferred Units are convertible into USAC common units at the election of the holders. To the extent the holders of the USAC Preferred Units have not elected to convert their preferred units by April 2023, USAC will have the option to redeem all or any portion of the USAC Preferred Units for cash. In addition, beginning April 2028, the holders of the USAC Preferred Units will have the right to require USAC to redeem all or any portion of the USAC Preferred Units, and USAC may elect to pay up to 50% of such redemption amount in USAC common units.

Energy Transfer Canada Redeemable Preferred Stock

Energy Transfer Canada has 300,000 shares of cumulative preferred stock issued and outstanding. The preferred stock is redeemable at Energy Transfer Canada's option at a redemption price of C$1,100 (US$867 at the September 30, 2021 exchange rate) per share. The preferred stock is redeemable by the holder contingent upon a change of control or liquidation of Energy Transfer Canada. The preferred stock is convertible to Energy Transfer Canada common shares in the event of an initial public offering by Energy Transfer Canada.

Dividends on the preferred stock were payable in-kind through the quarter ended June 30, 2021. The dividends paid-in-kind increased the liquidation preference such that, as of September 30, 2021, the preferred stock was convertible into 367,521 shares.

For the quarter ended September 30, 2021, Energy Transfer Canada declared cash dividends of C$8 million (US$6 million at the September 30, 2021 exchange rate) on the preferred stock that will be paid in the fourth quarter of 2021.

9. EQUITY

ET Common Units

The change in ET common units during the nine months ended September 30, 2021 was as follows:

	Number of Units
Number of common units at December 31, 2020	2,702.4
Common units issued in connection with the distribution reinvestment plan	2.7
Common units vested under equity incentive plans and other	0.7
Number of common units at September 30, 2021	2,705.8

ET Repurchase Program

During the nine months ended September 30, 2021, ET did not repurchase any ET common units under its current buyback program. As of September 30, 2021, $911 million remained available to repurchase under the current program.

ET Distribution Reinvestment Program

During the nine months ended September 30, 2021, distributions of $24 million were reinvested under the distribution reinvestment program. As of September 30, 2021, a total of 18 million ET common units remained available to be issued under the existing registration statement in connection with the distribution reinvestment program.

Cash Distributions on ET Common Units

Distributions declared and/or paid with respect to ET common units subsequent to December 31, 2020 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2020	February 8, 2021	February 19, 2021	$ 0.1525
March 31, 2021	May 11, 2021	May 19, 2021	0.1525
June 30, 2021	August 6, 2021	August 19, 2021	0.1525
September 30, 2021	November 5, 2021	November 19, 2021	0.1525

The Partnership's distribution on its common units with respect to the quarter ended March 31, 2020 was declared on March 31, 2020 and accrued as of that date. For the three months ended March 31, 2020, the consolidated statement of equity reflected distributions to common unitholders for two quarters. For the three months ended June 30, 2020, the amount reflected for distributions to common unitholders in the consolidated statements of equity reflected only the reinvestment of distributions paid in May 2020.

ET Preferred Units

Conversion of ETO Preferred Units to ET Preferred Units

In connection with the Rollup Mergers on April 1, 2021, as discussed in Note 1, all of ETO's previously outstanding preferred units were converted to ET Preferred Units with identical distribution and redemption rights, as described under "Description of ET Preferred Units" below.

As of and prior to March 31, 2021, the ET Preferred Units were reflected as noncontrolling interests on the Partnership's consolidated financial statements. Beginning April 1, 2021, the ET Preferred Units are reflected as limited partner interests in the Partnership's consolidated financial statements.

As of September 30, 2021, ET's outstanding preferred units included 950,000 Series A Preferred Units, 550,000 Series B Preferred Units, 18,000,000 Series C Preferred Units, 17,800,000 Series D Preferred Units, 32,000,000 Series E Preferred Units, 500,000 Series F Preferred Units, 1,100,000 Series G Preferred Units and 900,000 Series H Preferred Units.

The following table summarizes changes in the ET Preferred Units:

	Preferred Unitholders								
	Series A	Series B	Series C	Series D	Series E	Series F	Series G	Series H	Total
Balance, March 31, 2021	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Preferred units conversion	943	547	440	434	786	504	1,114	—	4,768
Units issued for cash	—	—	—	—	—	—	—	889	889
Distributions to partners	—	—	(8)	(9)	(15)	(17)	(39)	—	(88)
Other, net	—	—	—	—	—	—	—	(1)	(1)
Net income	15	9	8	9	15	8	20	2	86
Balance, June 30, 2021	958	556	440	434	786	495	1,095	890	5,654
Distributions to partners	(30)	(18)	(8)	(9)	(15)	—	—	—	(80)
Other, net	—	—	—	—	—	—	—	(2)	(2)
Net income	15	9	8	9	15	8	20	15	99
Balance, September 30, 2021	$ 943	$ 547	$ 440	$ 434	$ 786	$ 503	$ 1,115	$ 903	$ 5,671

Cash Distributions on ET Preferred Units

Distributions declared on the ET Preferred Units were as follows:

Period Ended	Record Date	Payment Date	Series A [1]	Series B [1]	Series C	Series D	Series E	Series F [1]	Series G [1]	Series H [1]
March 31, 2021	May 3, 2021	May 17, 2021	$ —	$ —	$ 0.4609	$ 0.4766	$ 0.4750	$ 33.75	$ 35.625	$ —
June 30, 2021	August 2, 2021	August 16, 2021	31.25	33.125	0.4609	0.4766	0.4750	—	—	—
September 30, 2021	November 1, 2021	November 15, 2021	—	—	0.4609	0.4766	0.4750	33.75	35.625	27.08 [2]

(1) Series A, Series B, Series F, Series G and Series H distributions are paid on a semi-annual basis.

(2) Represents initial prorated distribution.

Description of ET Preferred Units

Following is a summary of the distribution and redemption rights associated with the ET Preferred Units:

- *Series A Preferred Units*. Distributions on the Series A Preferred Units will accrue and be cumulative to, but excluding, February 15, 2023, at a rate of 6.250% per annum of the stated liquidation preference of $1,000. On and after February 15, 2023, distributions on the Series A Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.028% per annum. Distributions on the Series A Preferred Units will be payable semi-annually in arrears on the 15th day of February and August of each year. The Series A Preferred Units are redeemable at ET's option on or after February 15, 2023 at a redemption price of $1,000 per Series A Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

- *Series B Preferred Units.* Distributions on the Series B Preferred Units will accrue and be cumulative to, but excluding, February 15, 2028, at a rate of 6.625% per annum of the stated liquidation preference of $1,000. On and after February 15, 2028, distributions on the Series B Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.155% per annum. Distributions on the Series B Preferred Units will be payable semi-annually in arrears on the 15th day of February and August of each year. The Series B Preferred Units are redeemable at ET's option on or after February 15, 2028 at a redemption price of $1,000 per Series B Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

- *Series C Preferred Units.* Distributions on the Series C Preferred Units will accrue and be cumulative 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. Distributions on the Series C Preferred Units will be payable quarterly in arrears on the 15th day of February, May, August and November of each year. The Series C Preferred Units are redeemable at ET'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.* Distributions on the Series D Preferred Units will accrue and be cumulative 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 4.738% per annum. Distributions on the Series D Preferred Units will be payable quarterly in arrears on the 15th day of February, May, August and November of each year. The Series D Preferred Units are redeemable at ET'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.

- *Series E Preferred Units.* Distributions on the Series E Preferred Units will accrue and be cumulative to, but excluding, May 15, 2024, at a rate of 7.600% per annum of the stated liquidation preference of $25. On and after May 15, 2024, distributions on the Series E 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 5.161% per annum. Distributions on the Series E Preferred Units will be payable quarterly in arrears on the 15th day of February, May, August and November of each year. The Series E Preferred Units are redeemable at ET's option on or after May 15, 2024 at a redemption price of $25 per Series E Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

- *Series F Preferred Units.* Distributions on the Series F Preferred Units will accrue and be cumulative to, but excluding, May 15, 2025, at a rate equal to 6.750% per annum of the $1,000 liquidation preference. On and after May 15, 2025, the distribution rate on the Series F Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.134% per annum. Distributions on the Series F Preferred Units will be payable semi-annually in arrears on the 15th day of May and November of each year. The Series F Preferred Units are redeemable at ET's option on or after May 15, 2025 at a redemption price of $1,000 per Series F Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

- *Series G Preferred Units.* Distributions on the Series G Preferred Units will accrue and be cumulative to, but excluding, May 15, 2030, at a rate equal to 7.125% per annum of the $1,000 liquidation preference. On and after May 15, 2030, the distribution rate on the Series G Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.306% per annum. Distributions on the Series G Preferred Units will be payable semi-annually in arrears on the 15th day of May and November of each year. The Series G Preferred Units are redeemable at ET's option on or after May 15, 2030 at a redemption price of $1,000 per Series G Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.
- *Series H Preferred Units*. On June 15, 2021, the Partnership issued 900,000 Series H Preferred Units at a price to the public of $1,000 per unit. Distributions on the Series H Preferred Units will accrue and be cumulative to, but excluding, November 15, 2026, at a rate equal to 6.500% per annum of the $1,000 liquidation preference. On and after November 15, 2026 and each fifth anniversary thereafter, the distribution rate on the Series H Preferred Units will reset to be a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.694% per annum. Distributions on the Series H Preferred Units will be payable semi-annually in arrears on the 15th day of May and November of each year. The Series H Preferred Units are redeemable at ET's option during the three-month period prior to, and including, each distribution reset date at a redemption price of $1,000 per Series H Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Noncontrolling Interests

The Partnership's consolidated financial statements include Sunoco LP and USAC, both of which are publicly traded master limited partnerships, as well as other less-than-wholly-owned, consolidated joint ventures. The following sections describe cash distributions made by our publicly traded subsidiaries, Sunoco LP and USAC, both of which are required by their respective partnership agreements to distribute all cash on hand (less appropriate reserves determined by the boards of directors of their respective general partners) subsequent to the end of each quarter.

Sunoco LP Cash Distributions

Distributions on Sunoco LP's units declared and/or paid by Sunoco LP subsequent to December 31, 2020 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2020	February 8, 2021	February 19, 2021	$ 0.8255
March 31, 2021	May 11, 2021	May 19, 2021	0.8255
June 30, 2021	August 6, 2021	August 19, 2021	0.8255
September 30, 2021	November 5, 2021	November 19, 2021	0.8255

USAC Cash Distributions

Distributions on USAC's units declared and/or paid by USAC subsequent to December 31, 2020 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2020	January 25, 2021	February 5, 2021	$ 0.525
March 31, 2021	April 26, 2021	May 7, 2021	0.525
June 30, 2021	July 26, 2021	August 6, 2021	0.525
September 30, 2021	October 25, 2021	November 5, 2021	0.525

Accumulated Other Comprehensive Income (Loss)

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

	September 30, 2021	December 31, 2020
Available-for-sale securities	$ 23	$ 18
Foreign currency translation adjustment	12	7
Actuarial loss related to pensions and other postretirement benefits	(1)	(7)
Investments in unconsolidated affiliates, net	(13)	(14)
Total AOCI, net of tax	21	4
Amounts attributable to noncontrolling interest	(2)	2
Total AOCI included in partners' capital, net of tax	$ 19	$ 6

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Winter Storm Impacts

Winter Storm Uri, which occurred in February 2021, resulted in one-time impacts to the Partnership's consolidated net income and also affected the results of operations in certain segments. The recognition of the impacts of Winter Storm Uri during the nine months ended September 30, 2021 required management to make certain estimates and assumptions, including estimates of expected credit losses and assumptions related to the resolution of disputes with counterparties with respect to certain purchases and sales of natural gas. The ultimate realization of credit losses and the resolution of disputed purchases and sales of natural gas could materially impact the Partnership's financial condition and results of operations in future periods.

FERC Proceedings

By the Order issued January 16, 2019, the FERC initiated a review of Panhandle's existing rates pursuant to Section 5 of the Natural Gas Act ("NGA") to determine whether the rates currently charged by Panhandle are just and reasonable and set the matter for hearing. On August 30, 2019, Panhandle filed a general rate proceeding under Section 4 of the NGA. The Natural Gas Act Section 5 and Section 4 proceedings were consolidated by order of the Chief Judge on October 1, 2019. A hearing in the combined proceedings commenced on August 25, 2020 and adjourned on September 15, 2020. The initial decision by the administrative law judge was issued on March 26, 2021. On April 26, 2021, Panhandle filed its brief on exceptions to the initial decision. On May 17, 2021, Panhandle filed its brief opposing exceptions in this proceeding.

In May 2021, the FERC commenced an audit of Sunoco Pipeline LP ("SPLP") for the period from January 1, 2018 to present to evaluate SPLP's compliance with its FERC oil tariffs, the accounting requirements of the Uniform System of Accounts as prescribed by the FERC, and the FERC's Form No. 6, including Page 700, reporting requirements. The audit is ongoing.

Commitments

In the normal course of business, our subsidiaries purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on the Partnership's 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 the unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

We have certain non-cancelable rights-of-way ("ROW") commitments, which require fixed payments and either expire upon our chosen abandonment or at various dates in the future. The table below reflects ROW expense included in operating expenses in the accompanying consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
ROW expense	$ 18	$ 13	$ 33	$ 32

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.

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 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.

As of September 30, 2021 and December 31, 2020, accruals of approximately $130 million and $101 million, respectively, were reflected on our consolidated balance sheets related to contingencies that met both the probable and reasonably estimable criteria. In addition, we may recognize additional contingent losses in the future related to (i) contingent matters for which a loss is currently considered reasonably possible but not probable and/or (ii) losses in excess of amounts that have already been accrued for such contingent matters. In some of these cases, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. For such matters where additional contingent losses can be reasonably estimated, the range of additional losses is estimated to be up to approximately $80 million.

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 or our estimates of reasonably possible losses prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Dakota Access Pipeline

On July 27, 2016, the Standing Rock Sioux Tribe ("SRST") filed a lawsuit in the United States District Court for the District of Columbia ("District Court") challenging permits issued by the United States Army Corps of Engineers ("USACE") that allowed Dakota Access to cross the Missouri River at Lake Oahe in North Dakota. The case was subsequently amended to challenge an easement issued by the USACE that allowed the pipeline to cross land owned by the USACE adjacent to the Missouri River. Dakota Access and the Cheyenne River Sioux Tribe ("CRST") intervened. Separate lawsuits filed by the Oglala Sioux Tribe ("OST") and the Yankton Sioux Tribe ("YST") were consolidated with this action and several individual tribal members intervened (collectively, with SRST and CRST, the "Tribes"). On March 25, 2020, the District Court remanded the case back to the USACE for preparation of an Environment Impact Statement ("EIS"). On July 6, 2020, the District Court vacated the easement and ordered Dakota Access to be shut down and emptied of oil by August 5, 2020. Dakota Access and the USACE appealed to the United States Court of Appeals for the District of Columbia ("Court of Appeals") which granted an administrative stay of the District Court's July 6 order and ordered further briefing on whether to fully stay the July 6 order. On August 5, 2020, the Court of Appeals 1) granted a stay of the portion of the District Court order that required Dakota Access to shut the pipeline down and empty it of oil, 2) denied a motion to stay the March 25 order pending a decision on the merits by the Court of Appeals as to whether the USACE would be required to prepare an EIS, and 3) denied a motion to stay the District Court's order to vacate the easement during this appeal process. The August 5 order also states that the Court of Appeals expected the USACE to clarify its position with respect to whether USACE intended to allow the continued operation of the pipeline notwithstanding the vacatur of the easement and that the District Court may consider additional relief, if necessary.

On August 10, 2020, the District Court ordered the USACE to submit a status report by August 31, 2020, clarifying its position with regard to its decision-making process with respect to the continued operation of the pipeline. On August 31, 2020, the USACE submitted a status report that indicated that it considered the presence of the pipeline at the Lake Oahe crossing without an easement to constitute an encroachment on federal land, and that it was still considering whether to exercise its enforcement discretion regarding this encroachment. The Tribes subsequently filed a motion seeking an injunction to stop the operation of the pipeline and both of the USACE and Dakota Access filed briefs in opposition of the motion for injunction. The motion for injunction was fully briefed as of January 8, 2021.

On January 26, 2021, the Court of Appeals affirmed the District Court's March 25, 2020 order requiring an EIS and its July 6, 2020 order vacating the easement. In this same January 26 order, the Court of Appeals also overturned the District Court's July 6, 2020 order that the pipeline shut down and be emptied of oil. Dakota Access filed for rehearing en banc on April 12, 2021, which the Court of Appeals denied. Dakota Access filed a petition with the U.S. Supreme Court to hear the case.

The District Court scheduled a status conference for February 10, 2021 to discuss the effects of the Court of Appeals' January 26, 2021 order on the pending motion for injunctive relief, as well as USACE's expectations as to how it will proceed regarding its enforcement discretion regarding the easement. At the request of the USACE, on February 9, 2021 the District Court granted a two-month continuance for the status conference until April 9, 2021. On April 9, 2021, the District Court granted Dakota Access's request for the opportunity to file updates to its declarations supporting the opposition to injunctive relief and thereafter granted the Tribes' request to file updates to their declarations supporting their position with respect to injunctive relief. Dakota Access and the Tribes filed their supplemental declarations on April 19, 2021 and April 26, 2021, respectively. On April 26, 2021, the District Court requested that USACE advise it by May 3, 2021 as to USACE's current position, if it has one, with respect to the Motion. On May 3, 2021, USACE advised the District Court that it had not changed its position with respect to its opposition to the Tribes' motion for injunction. The USACE also advised the District Court that it expected that the EIS will be completed by March 2022. On May 21, 2021 the District Court denied the Plaintiffs' request for an injunction. The District Court further directed the parties to file a joint status report by June 11, 2021 concerning potential next steps in the litigation.

On June 22, 2021, the District Court terminated the consolidated lawsuits and dismissed all remaining outstanding counts without prejudice. The Court noted the availability of a motion to reopen the terminated proceedings if, for example, one of its earlier orders were violated. The Court also noted that should the Plaintiffs seek to challenge the forthcoming EIS, they would need to do so by filing a new complaint, and they could ask that it be assigned to the same Judge.

The pipeline continues to operate pending completion of the EIS. The USACE now estimates that the EIS will be complete by the end of 2022. ET cannot determine when or how future lawsuits will be resolved or the impact they may have on the Dakota Access pipelines; however, ET expects after the law and complete record are fully considered, any such proceeding will be resolved in a manner that will allow the pipeline to continue to operate.

In addition, lawsuits and/or regulatory proceedings or actions of this or a similar nature could result in interruptions to construction or operations of current or future projects, delays in completing those projects and/or increased project costs, all of which could have an adverse effect on our business and results of operations.

Mont Belvieu Incident

On June 26, 2016, a hydrocarbon storage well located on another operator's facility adjacent to Lone Star NGL LLC's ("Lone Star"), now known as Energy Transfer GC NGLs LLC, 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 resumed at the facilities in the fall of 2016, with the exception of one of Lone Star's storage wells at the North Terminal that has not been returned to service. Lone Star has obtained payment for most of the losses it has submitted to the adjacent operator. Lone Star continues to quantify and seek reimbursement for outstanding losses.

MTBE Litigation

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

As of September 30, 2021, Sunoco Defendants are defendants in five cases, including one case each initiated by the States of Maryland and Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants ETO, ETP Holdco Corporation, and Sunoco Partners Marketing & Terminals L.P. (“SPMT”).

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

On June 10, 2015, Adrian Dieckman (“Dieckman” or “Plaintiff”), a purported Regency unitholder, filed a class action complaint related to the Regency-ETO merger (the “Regency Merger”) 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, ET, ETO, Energy Transfer Partners GP, L.P., and the members of Regency’s board of directors.

The Regency Merger Litigation alleges that the Regency Merger breached the Regency partnership agreement. On March 29, 2016, the Delaware Court of Chancery granted the defendants’ motion to dismiss the lawsuit in its entirety. Plaintiff appealed, and the Delaware Supreme Court reversed the judgment of the Court of Chancery. Plaintiff then filed an Amended Verified Class Action Complaint, which defendants moved to dismiss. The Court of Chancery granted in part and denied in part the motions to dismiss, dismissing the claims against all defendants other than Regency GP LP and Regency GP LLC (the “Regency Defendants”). The Court of Chancery later granted Plaintiff’s unopposed motion for class certification. Trial was held on December 10-16, 2019, and a post-trial hearing was held on May 6, 2020. On February 15, 2021, the Court of Chancery ruled in favor of the Regency Defendants on all claims at issue in this litigation, determined that the Regency Merger was fair and reasonable to Regency, and denied Plaintiff any relief.

On March 19, 2021, Plaintiff filed a notice of appeal, and oral argument was held on October 20, 2021. The Regency Defendants cannot predict the outcome of this appeal but intend to vigorously oppose it.

Litigation Filed By or Against Williams

In April and May 2016, the Williams Companies, Inc. (“Williams”) filed two lawsuits (the “Williams Litigation”) against ET, LE GP, and, in one of the lawsuits, Energy Transfer Corp LP, ETE Corp GP, LLC, and Energy Transfer Equity GP, LLC (collectively, “ET Defendants”), alleging that ET Defendants breached their obligations under the ET-Williams merger agreement (the “Merger Agreement”). In general, Williams alleges that ET Defendants breached the Merger Agreement by (a) failing to use commercially reasonable efforts to obtain from Latham & Watkins LLP (“Latham”) the delivery of a tax opinion concerning Section 721 of the Internal Revenue Code (“721 Opinion”), (b) issuing the Partnership’s series A convertible preferred units (the “Issuance”), and (c) making allegedly untrue representations and warranties in the Merger Agreement.

After a two-day trial on June 20 and 21, 2016, the Court ruled in favor of ET Defendants and issued a declaratory judgment that ET could terminate the merger after June 28, 2016 because of Latham’s inability to provide the required 721 Opinion. The Court did not reach a decision regarding Williams’ claims related to the Issuance nor the alleged untrue representations and warranties. On March 23, 2017, the Delaware Supreme Court affirmed the Court’s ruling on the June 2016 trial.

In September 2016, the parties filed amended pleadings. Williams filed an amended complaint seeking a $410 million termination fee based on the alleged breaches of the Merger Agreement listed above. ET Defendants filed amended counterclaims and affirmative defenses, asserting that Williams materially breached the Merger Agreement by, among other things, (a) failing to use its reasonable best efforts to consummate the merger, (b) failing to provide material information to ET for inclusion in the Form S-4 related to the merger, (c) failing to facilitate the financing of the merger, and (d) breaching the Merger Agreement’s forum-selection clause.

Trial was held regarding the parties’ amended claims on May 10-17, 2021, and a post-trial hearing was held on September 16, 2021. ET Defendants cannot predict the outcome of the Williams Litigation nor can the ET Defendants predict the amount of time and expense that will be required to resolve the Williams Litigation. ET Defendants believe that Williams’ claims are without merit and intend to defend vigorously against them.

Rover

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and other defendants seeking to recover civil penalties allegedly owed and certain injunctive relief related to permit compliance. The defendants filed several motions to dismiss, which were granted on all counts. The Ohio EPA appealed, and on December 9, 2019, the Fifth District Court of Appeals entered a unanimous judgment affirming the trial court. The Ohio EPA sought review from the Ohio Supreme Court, which the defendants opposed in briefs filed in February 2020. On April 22, 2020, the Ohio Supreme Court granted the Ohio EPA's request for review. Briefing has concluded and oral argument was held on January 26, 2021. The parties are awaiting a decision.

Revolution

On September 10, 2018, a pipeline release and fire (the "Incident") occurred on the Revolution pipeline, a natural gas gathering line located in Center Township, Beaver County, Pennsylvania. There were no injuries.

The Pennsylvania Office of Attorney General has commenced an investigation regarding the Incident, and the United States Attorney for the Western District of Pennsylvania has issued a federal grand jury subpoena for documents relevant to the Incident. The scope of these investigations is not further known at this time.

Chester County, Pennsylvania Investigation

In December 2018, the former Chester County District Attorney (the "Chester County DA") sent a letter to the Partnership stating that his office was investigating the Partnership and related entities for "potential crimes" related to the Mariner East pipelines.

Subsequently, the matter was submitted to an Investigating Grand Jury in Chester County, Pennsylvania, which has issued subpoenas seeking documents and testimony. On September 24, 2019, the Chester County DA sent a Notice of Intent to the Partnership of its intent to pursue an abatement action if certain conditions were not remediated. The Partnership responded to the Notice of Intent within the prescribed time period.

In December 2019, the Chester County DA announced charges against a current employee related to the provision of security services. On June 25, 2020, a preliminary hearing was held on the charges against the employee, and the judge dismissed all charges.

On April 22, 2021, the Chester County DA filed a Complaint and Consent Decree in the Court of Common Pleas of Chester County, Pennsylvania constituting a settlement agreement between the Chester County DA and the Partnership. A status conference was held on May 10, 2021, and an Amended Consent Decree was filed on June 16, 2021, which has not yet been entered by the Court.

Delaware County, Pennsylvania Investigation

On March 11, 2019, the Delaware County District Attorney's Office (the "Delaware County DA") announced that the Delaware County DA and the Pennsylvania Attorney General's Office (the "AG"), at the request of the Delaware County DA, are conducting an investigation of alleged criminal misconduct involving the construction and related activities of the Mariner East pipelines in Delaware County. On March 16, 2020, the AG served a Statewide Investigating Grand Jury subpoena for documents relating to inadvertent returns and water supplies related to the Mariner East pipelines. The Partnership has complied with the subpoena. On October 5, 2021, the AG held a press conference related to the Mariner East pipelines, released a Grand Jury Presentment and subsequently filed a criminal complaint against ET in the Magisterial District Court No. 12-2-02 in Dauphin County, Pennsylvania with respect to 47 misdemeanor charges related to the discharge of industrial waste and pollution and one felony charge related to the failure to report information related to the discharges. The Partnership will defend itself vigorously against these charges. On October 13, 2021, the AG announced that he is running for Governor of Pennsylvania.

Shareholder Litigation Regarding Pennsylvania Pipeline Construction

Four purported unitholders of ET filed derivative actions against various past and current members of ET's Board of Directors, LE GP, and ET, as a nominal defendant that assert claims for breach of fiduciary duties, unjust enrichment, waste of corporate assets, breach of ET's limited partnership agreement, tortious interference, abuse of control, and gross mismanagement related primarily to matters involving the construction of pipelines in Pennsylvania. They also seek damages and changes to ET's corporate governance structure. See *Bettiol v. LE GP*, Case No. 3:19-cv-02890-X (N.D. Tex.); *Davidson v. Kelcy L. Warren*, Cause No. DC-20-02322 (44th Judicial District of Dallas County, Texas); *Harris v. Kelcy L. Warren*, Case No. 2:20-cv-00364-GAM (E.D. Pa.); and *King v. LE GP*, Case No. 3:20-cv-00719-X (N.D. Tex.).

Another purported unitholder of ET, Allegheny County Employees' Retirement System ("ACERS"), individually and on behalf of all others similarly situated, filed a suit under the federal securities laws purportedly on behalf of a class, against ET and three of ET's directors, Kelcy L. Warren, John W. McReynolds, and Thomas E. Long. See *Allegheny County Emps.' Ret. Sys. v. Energy Transfer LP*, Case No. 2:20-00200-GAM (E.D. Pa.). On June 15, 2020, ACERS filed an amended complaint and added as additional defendants ET directors Marshall McCrea and Matthew Ramsey, as well as Michael J. Hennigan and Joseph McGinn. The amended complaint asserts claims for violations of Sections 10(b) and 20(a) of the Exchange Act and Rule 10b-5 promulgated thereunder related primarily to matters involving the construction of pipelines in Pennsylvania. On August 14, 2020, the defendants filed a motion to dismiss ACERS' amended complaint. On April 6, 2021, the court granted in part and denied in part the defendants' motion to dismiss. The court held that ACERS could proceed with its claims regarding certain statements put at issue by the amended complaint while also dismissing claims based on other statements. The court also dismissed without prejudice the claims against defendants McReynolds, McGinn, and Hennigan. The defendants cannot predict the outcome of these lawsuits or any lawsuits that might be filed subsequent to the date of this filing; nor can the defendants predict the amount of time and expense that will be required to resolve these lawsuits. However, the defendants believe that the claims are without merit and intend to vigorously contest them.

Cline Class Action

On July 7, 2017, Perry Cline filed a class action complaint in the Eastern District of Oklahoma against Sunoco (R&M), LLC (now known as Energy Transfer R&M) and SPMT that alleged SPMT failed to make timely payments of oil and gas proceeds from Oklahoma wells and to pay statutory interest for those untimely payments. On October 3, 2019, the Court certified a class to include all persons who received untimely payments from Oklahoma wells on or after July 7, 2012 and who have not already been paid statutory interest on the untimely payments (the "Class"). Excluded from the Class are those entitled to payments of proceeds that qualify as "minimum pay," prior period adjustments, and pass through payments, as well as governmental agencies and publicly traded oil and gas companies.

After a bench trial, on August 17, 2020, Judge John Gibney (sitting from the Eastern District of Virginia) issued an opinion that awarded the Class actual damages of $74.8 million for late payment interest for identified and unidentified royalty owners and interest-on-interest. This amount was later amended to $80.7 million to account for interest accrued from trial (the "Order"). Judge Gibney also awarded punitive damages in the amount of $75 million. The Class is also seeking attorneys' fees.

On August 27, 2020, SPMT filed its Notice of Appeal with the 10th Circuit and appealed the entirety of the Order. The matter has now been fully briefed, and oral argument has been set for November 15, 2021. SPMT cannot predict the outcome of the case, nor can SPMT predict the amount of time and expense that will be required to resolve the appeal, but intends to vigorously appeal the entirety of the Order.

Environmental Matters

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

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on our 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.

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 be contractually 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. are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that the Partnership no longer operates, closed and/or sold refineries and other formerly owned sites.
- the Partnership is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party (“PRP”). As of September 30, 2021, the Partnership had been named as a PRP at approximately 33 identified or potentially identifiable “Superfund” sites under federal and/or comparable state law. The Partnership is usually one of a number of companies identified as a PRP at a site. The Partnership has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon the Partnership’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 require disclosure in our consolidated financial statements.

	September 30, 2021	December 31, 2020
Current	$ 44	$ 44
Non-current	253	262
Total environmental liabilities	$ 297	$ 306

We have 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 nine months ended September 30, 2021 and 2020, the Partnership recorded $18 million and $22 million, respectively, of expenditures related to environmental cleanup programs.

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

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

11. REVENUE

Disaggregation of Revenue

The Partnership's consolidated financial statements reflect eight reportable segments, which also represent the level at which the Partnership aggregates revenue for disclosure purposes. Note 13 depicts the disaggregation of revenue by segment.

Contract Balances with Customers

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

The Partnership recognizes a contract asset when making upfront consideration payments to certain customers or when providing services to customers prior to the time at which the Partnership is contractually allowed to bill for such services.

The Partnership recognizes a contract liability if the customer's payment of consideration precedes the Partnership's fulfillment of the performance obligations. Certain contracts contain provisions requiring customers to pay a fixed minimum fee, but allow customers to apply such fees against services to be provided at a future point in time. These amounts are reflected as deferred revenue until the customer applies the deficiency fees to services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints. Additionally, Sunoco LP maintains some franchise agreements requiring dealers to make one-time upfront payments for long term license agreements. Sunoco LP recognizes a contract liability when the upfront payment is received and recognizes revenue over the term of the license.

The following table summarizes the consolidated activity of our contract liabilities:

	Contract Liabilities
Balance, December 31, 2020	$ 308
Additions	611
Revenue recognized	(512)
Balance, September 30, 2021	$ 407
Balance, December 31, 2019	$ 377
Additions	598
Revenue recognized	(614)
Balance, September 30, 2020	$ 361

The balances of Sunoco LP's contract assets were as follows:

	September 30, 2021	December 31, 2020
Contract balances:		
Contract assets	$ 148	$ 121
Accounts receivable from contracts with customers	473	256

Performance Obligations

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

As of September 30, 2021, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations was $40.13 billion, and the Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	Years Ending December 31,				
	2021 (remainder)	2022	2023	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of September 30, 2021	$ 1,662	$ 6,010	$ 5,504	$ 26,950	$ 40,126

12. DERIVATIVE ASSETS AND LIABILITIES

Commodity Price Risk

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

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

We use futures, swaps and options to hedge the sales price of natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales in 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 futures and swaps to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in margins for certain refined products and to lock in the price of a portion of natural gas purchases or sales. These contracts are not designated as hedges for accounting purposes.

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

The following table details our outstanding commodity-related derivatives:

	September 30, 2021		December 31, 2020	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX [(1)]	(81,963)	2021-2022	(44,225)	2021-2022
Fixed Swaps/Futures	475	2021-2023	1,603	2021-2022
Power (Megawatt):				
Forwards	712,400	2021-2029	1,392,400	2021-2029
Futures	(640,800)	2021-2022	18,706	2021-2022
Options – Puts	290,400	2021-2022	519,071	2021
Options – Calls	36,704	2021-2022	2,343,293	2021
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(8,893)	2021-2022	(29,173)	2021-2022
Swing Swaps IFERC	(48,675)	2021-2022	11,208	2021
Fixed Swaps/Futures	(45,588)	2021-2023	(53,575)	2021-2022
Forward Physical Contracts	(10,071)	2021	(11,861)	2021
NGLs (MBbls) – Forwards/Swaps	2,785	2021-2023	(5,840)	2021-2022
Refined Products (MBbls) – Futures	(3,272)	2021-2023	(2,765)	2021
Crude (MBbls) – Forwards/Swaps	1,693	2021-2022	—	—
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(21,255)	2021	(30,113)	2021
Fixed Swaps/Futures	(21,255)	2021	(30,113)	2021
Hedged Item – Inventory	21,255	2021	30,113	2021

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

Interest Rate Risk

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

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

Term	Type[1]	Notional Amount Outstanding September 30, 2021	Notional Amount Outstanding December 31, 2020
July 2021[2][3]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	$ —	$ 400
July 2022[2]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	400	400
July 2023[2]	Forward-starting to pay a fixed rate of 3.78% and receive a floating rate	200	—
July 2024[2]	Forward-starting to pay a fixed rate of 3.88% and receive a floating rate	200	—

(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.

(3) The July 2021 interest rate swaps were amended in June 2021.

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 industrial end-users, 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 with 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 our statement of operations or statement of comprehensive income (loss).

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	September 30, 2021	December 31, 2020	September 30, 2021	December 31, 2020
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 2	$ 25	$ (20)	$ (32)
	2	25	(20)	(32)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	330	90	(400)	(166)
Commodity derivatives	702	53	(661)	(71)
Interest rate derivatives	—	—	(376)	(448)
	1,032	143	(1,437)	(685)
Total derivatives	$ 1,034	$ 168	$ (1,457)	$ (717)

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

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	September 30, 2021	December 31, 2020	September 30, 2021	December 31, 2020
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (376)	$ (448)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	702	53	(661)	(71)
Broker cleared derivative contracts	Other current assets (liabilities)	332	115	(420)	(198)
Total gross derivatives		1,034	168	(1,457)	(717)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(645)	(44)	645	44
Counterparty netting	Other current assets (liabilities)	(327)	(64)	327	64
Total net derivatives		$ 62	$ 60	$ (485)	$ (609)

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

The following table summarizes the location and amounts recognized in our consolidated statements of operations with respect to our derivative financial instruments:

	Location	Amount of Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2021	2020	2021	2020
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$ 14	$ 4	$ 12	$ 15
Commodity derivatives – Non-trading	Cost of products sold	(71)	(44)	(206)	53
Interest rate derivatives	Gains (losses) on interest rate derivatives	1	55	72	(277)
Total		$ (56)	$ 15	$ (122)	$ (209)

13. REPORTABLE SEGMENTS

Our reportable segments, which conduct their business primarily in the United States, are as follows:

- intrastate transportation and storage;
- interstate transportation and storage;
- midstream;
- NGL and refined products transportation and services;
- crude oil transportation and services;
- investment in Sunoco LP;
- investment in USAC; and
- all other.

Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

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

We report Segment Adjusted EBITDA and consolidated Adjusted EBITDA as measures of segment performance. We define Segment Adjusted EBITDA and consolidated Adjusted EBITDA as total partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Inventory adjustments that are excluded from the calculation of Adjusted EBITDA represent only the changes in lower of cost or market reserves on inventory that is carried at LIFO. These amounts are unrealized valuation adjustments applied to Sunoco LP’s fuel volumes remaining in inventory at the end of the period.

Segment Adjusted EBITDA and consolidated Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

The following tables present financial information by segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 1,112	$ 614	$ 5,940	$ 1,615
Intersegment revenues	105	40	1,126	148
	1,217	654	7,066	1,763
Interstate transportation and storage:				
Revenues from external customers	412	466	1,317	1,365
Intersegment revenues	6	5	33	15
	418	471	1,350	1,380
Midstream:				
Revenues from external customers	560	585	1,709	1,477
Intersegment revenues	2,359	792	6,081	2,088
	2,919	1,377	7,790	3,565
NGL and refined products transportation and services:				
Revenues from external customers	4,499	2,207	11,726	5,991
Intersegment revenues	763	416	2,048	1,466
	5,262	2,623	13,774	7,457
Crude oil transportation and services:				
Revenues from external customers	4,577	2,849	12,497	8,873
Intersegment revenues	1	1	1	4
	4,578	2,850	12,498	8,877
Investment in Sunoco LP:				
Revenues from external customers	4,772	2,801	12,626	8,104
Intersegment revenues	7	4	16	53
	4,779	2,805	12,642	8,157
Investment in USAC:				
Revenues from external customers	156	158	464	500
Intersegment revenues	3	3	9	9
	159	161	473	509
All other:				
Revenues from external customers	576	275	2,481	995
Intersegment revenues	120	92	303	377
	696	367	2,784	1,372
Eliminations	(3,364)	(1,353)	(9,617)	(4,160)
Total revenues	$ 16,664	$ 9,955	$ 48,760	$ 28,920

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$ 172	$ 203	$ 3,209	$ 630
Interstate transportation and storage	334	425	1,118	1,232
Midstream	556	530	1,321	1,280
NGL and refined products transportation and services	706	762	2,089	2,099
Crude oil transportation and services	496	631	1,490	1,741
Investment in Sunoco LP	198	189	556	580
Investment in USAC	99	104	299	315
All other	18	22	153	62
Adjusted EBITDA (consolidated)	2,579	2,866	10,235	7,939
Depreciation, depletion and amortization	(943)	(912)	(2,837)	(2,715)
Interest expense, net of interest capitalized	(558)	(569)	(1,713)	(1,750)
Impairment losses	—	(1,474)	(11)	(2,803)
Gains (losses) on interest rate derivatives	1	55	72	(277)
Non-cash compensation expense	(26)	(30)	(81)	(93)
Unrealized gains (losses) on commodity risk management activities	(19)	(30)	74	(27)
Inventory valuation adjustments (Sunoco LP)	9	11	168	(126)
Losses on extinguishments of debt	—	—	(8)	(62)
Adjusted EBITDA related to unconsolidated affiliates	(141)	(169)	(400)	(480)
Equity in earnings (losses) of unconsolidated affiliates	71	(32)	191	46
Impairment of investment in an unconsolidated affiliate	—	(129)	—	(129)
Other, net	11	53	—	(48)
Income (loss) before income tax expense	984	(360)	5,690	(525)
Income tax expense	(77)	(41)	(234)	(168)
Net income (loss)	$ 907	$ (401)	$ 5,456	$ (693)

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 for the year ended December 31, 2020 filed with the SEC on February 19, 2021. 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, 2020 filed with the SEC on February 19, 2021 and "Part II - Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 filed with the SEC on August 5, 2021. Additional information on forward-looking statements is discussed below in "Forward-Looking Statements."

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "ET" mean Energy Transfer LP and its consolidated subsidiaries.

RECENT DEVELOPMENTS

Series H Preferred Units Issuance

On June 15, 2021, the Partnership issued 900,000 of its 6.500% Series H Preferred Units at a price of $1,000 per unit. The net proceeds were used to repay amounts outstanding under the Partnership's term loan and for general partnership purposes.

Winter Storm Impacts

Winter Storm Uri, which occurred in February 2021, resulted in one-time impacts to the Partnership's consolidated net income and Adjusted EBITDA and also affected the results of operations in certain segments, as discussed in "Results of Operations". The recognition of the impacts of Winter Storm Uri during the nine months ended September 30, 2021 required management to make certain estimates and assumptions, including estimates of expected credit losses and assumptions related to the resolution of disputes with counterparties with respect to certain purchases and sales of natural gas. The ultimate realization of credit losses and the resolution of disputed purchases and sales of natural gas could materially impact the Partnership's financial condition and results of operations in future periods.

Enable Acquisition

On February 16, 2021, the Partnership entered into a definitive merger agreement to acquire Enable. Under the terms of the merger agreement, Enable's common unitholders will receive 0.8595 of an ET common unit in exchange for each Enable common unit. In addition, each outstanding Enable preferred unit will be exchanged for 0.0265 of a Series G Preferred Unit, and ET will make a $10 million cash payment for Enable's general partner. In May 2021, the Enable common unitholders voted to approve the merger. The transaction is subject to the satisfaction of customary closing conditions, including Hart-Scott-Rodino Act ("HSR") clearance.

The Federal Trade Commission ("FTC") has issued requests for additional information and documentary material (the "Second Request"). The effect of the Second Request is to extend the waiting period imposed by the HSR Act until 30 days after the Partnership and Enable have certified substantial compliance with the Second Request, unless that period is extended voluntarily or terminated sooner by the FTC. We continue to believe that the FTC will grant clearance of the transaction, and we remain fully committed to closing the Enable merger under the terms of the merger agreement. We expect to close the transaction in the fourth quarter of 2021.

Rollup Mergers

On April 1, 2021, ET, ETO and certain of ETO's subsidiaries consummated several internal reorganization transactions (the "Rollup Mergers"). In connection with the Rollup Mergers, Sunoco Logistics Operations merged with and into ETO, with ETO surviving, and immediately thereafter, ETO merged with and into ET, with ET surviving. The impacts of the Rollup Mergers also included the following:

- All of ETO's long-term debt was assumed by ET, as more fully described in Note 7 to the consolidated financial statements in "Item 1. Financial Statements."

- Each issued and outstanding ETO preferred unit was converted into the right to receive one newly created ET preferred unit. A description of the ET Preferred Units is included in Note 9 to the consolidated financial statements in “Item 1. Financial Statements.”
- Each of ETO’s issued and outstanding Class K, Class L, Class M and Class N units, all of which were held by ETP Holdco Corporation, a wholly-owned subsidiary of ETO, were converted into an aggregate 675,625,000 newly created Class B Units representing limited partner interests in ET.

Sunoco LP’s Acquisitions

In September and October 2021, Sunoco LP acquired a total of nine refined product terminals in two separate transactions for approximately $256 million.

Quarterly Cash Distribution

In October 2021, ET announced its quarterly distribution of $0.1525 per unit ($0.61 annualized) on ET common units for the quarter ended September 30, 2021.

Regulatory Update

Interstate Natural Gas Transportation Regulation

Rate Regulation

Effective January 2018, the 2017 Tax Cuts 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. In the rehearing order, the FERC clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs. On July 31, 2020, the United States Court of Appeals for the District of Columbia Circuit issued an opinion upholding the FERC’s decision denying a separate master limited partnership recovery of an income tax allowance and its decision not to require the master limited partnership to refund accumulated deferred income tax balances. In light of the rehearing order’s clarification regarding an individual entity’s ability to argue in support of recovery of an income tax allowance and the court’s subsequent opinion upholding denial of an income tax allowance to a master limited partnership, the impact of the FERC's policy on the treatment of income taxes on the rates we can charge for FERC-regulated transportation services is unknown at this time.

Even without application of the FERC’s recent rate making-related policy statements and rulemakings, 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, including ROE and tax-related components, although changes in these components may tend to decrease our cost-of-service rate, other components in the cost-of-service rate calculation may increase and result in a newly calculated cost-of-service rate that is less than, 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, Midcontinent Express and Fayetteville Express, 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. 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 Revised Policy Statement, changes to ROE methodology, or other FERC policies, 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 our cost-of-service components and the outcomes of any challenges to our rates by the FERC or our shippers.

On July 18, 2018, the FERC issued a final rule establishing procedures to evaluate rates charged by the FERC-jurisdictional gas pipelines in light of the Tax Act and the FERC’s Revised Policy Statement. By order issued January 16, 2019, the FERC initiated a review of Panhandle’s existing rates pursuant to Section 5 of the NGA to determine whether the rates currently charged by Panhandle are just and reasonable and set the matter for hearing. Panhandle filed a cost and revenue study on April 1, 2019 and an NGA Section 4 rate case on August 30, 2019. The Section 4 and Section 5 proceedings were consolidated by order of the Chief Judge on October 1, 2019. A hearing in the combined proceedings commenced on August 25, 2020 and adjourned on September 15, 2020. The initial decision by the administrative law judge was issued on March 26, 2021. On April 26, 2021, Panhandle filed its brief on exceptions to the initial decision. On May 17, 2021, Panhandle filed its reply brief on exception to the initial decision.

Pipeline Certification

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 filed by us on May 26, 2021. 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 Common Carrier 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 for Finished Goods, or PPI-FG. Many existing pipelines utilize the FERC liquids index to change transportation rates annually. 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. In a December 2020 order, FERC determined that during the five-year period commencing July 1, 2021 and ending June 30, 2026, common carriers charging indexed rates will be permitted to adjust their indexed ceilings annually by PPI-FG plus 0.78 percent. Requests for rehearing of the December 2020 order were filed on January 19, 2021, and remain pending before FERC. Accordingly, the FERC's final determination of the index rate coupled with the anticipated and subsequent appeals of the December 2020 order could adversely impact the final determination of the FERC approved index.

FERC has also implemented changes related to its treatment of federal income taxes. The change in treatment impacts two rate components. Those components are the allowance for income taxes and the amount for accumulated deferred income taxes. These changes will primarily impact any cost-of-service related filing and our revenues associated with any cost-based service could be adversely affected by future FERC or judicial rulings. However, we believe that these impacts, if any, will be minimal.

Results of Operations

We report Segment Adjusted EBITDA and consolidated Adjusted EBITDA as measures of segment performance. We define Segment Adjusted EBITDA and consolidated Adjusted EBITDA as total partnership 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, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Inventory adjustments that are excluded from the calculation of Adjusted EBITDA represent only the changes in lower of cost or market reserves on inventory that is carried at LIFO. These amounts are unrealized valuation adjustments applied to Sunoco LP's fuel volumes remaining in inventory at the end of the period.

Segment Adjusted EBITDA and consolidated Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA and consolidated Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates. The use of Segment Adjusted EBITDA or Adjusted EBITDA related to unconsolidated affiliates as an analytical tool should be limited accordingly.

Segment Adjusted EBITDA, as reported for each segment in the table below, is analyzed for each segment in the section titled "Segment Operating Results." Adjusted EBITDA 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.

Consolidated Results

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Change	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$ 172	$ 203	$ (31)	$ 3,209	$ 630	$ 2,579
Interstate transportation and storage	334	425	(91)	1,118	1,232	(114)
Midstream	556	530	26	1,321	1,280	41
NGL and refined products transportation and services	706	762	(56)	2,089	2,099	(10)
Crude oil transportation and services	496	631	(135)	1,490	1,741	(251)
Investment in Sunoco LP	198	189	9	556	580	(24)
Investment in USAC	99	104	(5)	299	315	(16)
All other	18	22	(4)	153	62	91
Adjusted EBITDA (consolidated)	2,579	2,866	(287)	10,235	7,939	2,296
Depreciation, depletion and amortization	(943)	(912)	(31)	(2,837)	(2,715)	(122)
Interest expense, net of interest capitalized	(558)	(569)	11	(1,713)	(1,750)	37
Impairment losses	—	(1,474)	1,474	(11)	(2,803)	2,792
Gains (losses) on interest rate derivatives	1	55	(54)	72	(277)	349
Non-cash compensation expense	(26)	(30)	4	(81)	(93)	12
Unrealized gains (losses) on commodity risk management activities	(19)	(30)	11	74	(27)	101
Inventory valuation adjustments (Sunoco LP)	9	11	(2)	168	(126)	294
Losses on extinguishments of debt	—	—	—	(8)	(62)	54
Adjusted EBITDA related to unconsolidated affiliates	(141)	(169)	28	(400)	(480)	80
Equity in earnings (losses) of unconsolidated affiliates	71	(32)	103	191	46	145
Impairment of investment in an unconsolidated affiliate	—	(129)	129	—	(129)	129
Other, net	11	53	(42)	—	(48)	48
Income (loss) before income tax expense	984	(360)	1,344	5,690	(525)	6,215
Income tax expense	(77)	(41)	(36)	(234)	(168)	(66)
Net income (loss)	$ 907	$ (401)	$ 1,308	$ 5,456	$ (693)	$ 6,149

Adjusted EBITDA (consolidated). For the three months ended September 30, 2021 compared to the same period last year, Adjusted EBITDA decreased 10% due to the net impacts of multiple factors across each of our reportable segments. The primary drivers of the Adjusted EBITDA decrease were in our interstate transportation and storage, NGL and refined products transportation and services, and crude oil transportation and services segments. In our interstate transportation and storage segment, the decrease in Adjusted EBITDA was primarily driven by shipper contract expirations and a shipper bankruptcy. In our NGL and refined products transportation and services segment, the decrease in Adjusted EBITDA was primarily driven by increased utilities and employee related costs, while several variances within our segment margin were largely offsetting. In our crude oil transportation and services segment, the decrease in Adjusted EBITDA reflected a decrease in margin from our crude oil acquisition and marketing business, as well as increases in operating expense and selling, general and administrative expenses.

For the nine months ended September 30, 2021 compared to the same period last year, Adjusted EBITDA increased 29%, primarily due to the impacts of Winter Storm Uri in February 2021. The most significant impacts from the storm were recognized in our intrastate transportation and storage segment, where realized storage margin increased by $1.52 billion compared to the prior period as a result of withdrawals during the storm. In addition, realized natural gas sales increased $936 million and retained fuel revenues increased $114 million in our intrastate transportation and storage segment, and these increases were also primarily due to the impacts of the storm.

Additional information on changes impacting Adjusted EBITDA for the three and nine months ended September 30, 2021 compared to the same periods last year, including other impacts from Winter Storm Uri and other non-storm-related factors, is available below in “Segment Operating Results.”

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased for the three and nine months ended September 30, 2021 compared to the same period last year primarily due to incremental depreciation related to assets recently placed in service.

Interest Expense, net. Interest expense, net of interest capitalized decreased for the three and nine months ended September 30, 2021 compared to the same periods last year primarily due to the following:

- the Partnership’s interest expense decreased $8 million and $30 million for the three and nine months ended September 30, 2021, respectively, primarily due to lower total debt outstanding and lower borrowing costs on recently refinanced and floating rate debt, partially offset by lower interest capitalized; and
- Sunoco LP’s interest expense decreased $3 million and $7 million for the three and nine months ended September 30, 2021, respectively, primarily attributable to a slight decrease in average total long-term debt and decrease in the weighted average interest rate on long-term debt for the respective periods.

Impairment Losses. For the nine months ended September 30, 2021, impairment losses included a total of $5 million recognized by USAC related to its compression equipment, as well as a $6 million impairment of intangible assets related to customer contracts within the Partnership’s crude operations.

For the three months ended September 30, 2020, the Partnership recognized goodwill impairments totaling $1.46 billion and fixed asset impairments totaling $19 million primarily due to decreases in projected future cash flow as a result of the overall market demand decline. In addition, USAC recognized an equipment impairment of $2 million based on changes in market conditions. For the nine months ended September 30, 2020, impairment losses also included goodwill impairments recognized by the Partnership during the first quarter of 2020 totaling $706 million due to decreases in projected future cash flows as a result of overall market demand decline and a goodwill impairment recognized by USAC of $619 million, as well as an equipment impairment of $4 million based on changes in market conditions during the second quarter of 2020.

Gains (Losses) on Interest Rate Derivatives. Gains and losses on interest rate derivatives during the three and nine months ended September 30, 2021 resulted from changes in forward interest rates, which caused our forward-starting swaps to change in value.

Unrealized Gains (Losses) on Commodity Risk Management Activities. The unrealized gains and losses on our commodity risk management activities include changes in fair value of commodity derivatives and the hedged inventory included in designated fair value hedging relationships. Information on the unrealized gains and losses within each segment are included in “Segment Operating Results” below, and additional information on the commodity-related derivatives, including notional volumes, maturities and fair values, is available in “Item 3. Quantitative and Qualitative Disclosures About Market Risk” and in Note 12 to our consolidated financial statements included in “Item 1. Financial Statements.”

Inventory Valuation Adjustments. Inventory valuation adjustments represent changes in lower of cost or market using the last-in, first-out method on Sunoco LP’s inventory. These amounts are unrealized valuation adjustments applied to fuel volumes remaining in inventory at the end of the period. For the three months ended September 30, 2021 and September 30, 2020, increases in fuel prices reduced lower of cost or market reserve requirements by $9 million and $11 million, respectively. For the nine months ended September 30, 2021, an increase in fuel prices reduced lower of cost or market reserve requirements for the period by $168 million. For the nine months ended September 30, 2020, a decline in fuel prices increased lower of cost or market reserve requirements for the period by $126 million, resulting in an adverse impact to net income.

Losses on Extinguishments of Debt. During the nine months ended September 30, 2021, the losses on extinguishments of debt also included Sunoco LP’s January 2021 repurchase of the remainder of its 2023 senior notes as well as the Partnership’s partial repayment of its Term Loan in April 2021. During the nine months ended September 30, 2020, amounts were related to ETO’s senior notes redemption in January 2020.

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

Impairment of Investment in an Unconsolidated Affiliate. During the three and nine months ended September 30, 2020, the Partnership recorded an impairment to its investment in White Cliffs of $129 million due to a decrease in projected future revenues and cash flows as a result of the overall market demand decline that occurred subsequent to the SemGroup, LLC acquisition and related purchase price allocation in December 2019.

Other, net. Other, net primarily includes the amortization of regulatory assets and other income and expense amounts.

Income Tax Expense. For the three and nine months ended September 30, 2021 compared to the same periods last year, income tax expense increased due to higher earnings from the Partnership's consolidated corporate subsidiaries.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$ 44	$ 50	$ (6)	$ 123	$ 127	$ (4)
FEP [(1)]	—	(106)	106	—	(158)	158
MEP	(5)	(1)	(4)	(12)	(3)	(9)
White Cliffs	(1)	2	(3)	—	19	(19)
Other	33	23	10	80	61	19
Total equity in earnings (losses) of unconsolidated affiliates	$ 71	$ (32)	$ 103	$ 191	$ 46	$ 145
Adjusted EBITDA related to unconsolidated affiliates[(2)]:						
Citrus	$ 87	$ 96	$ (9)	$ 251	$ 264	$ (13)
FEP	—	19	(19)	—	57	(57)
MEP	4	8	(4)	14	23	(9)
White Cliffs	4	11	(7)	14	38	(24)
Other	46	35	11	121	98	23
Total Adjusted EBITDA related to unconsolidated affiliates	$ 141	$ 169	$ (28)	$ 400	$ 480	$ (80)
Distributions received from unconsolidated affiliates:						
Citrus	$ 106	$ 48	$ 58	$ 191	$ 155	$ 36
FEP	—	20	(20)	4	55	(51)
MEP	1	4	(3)	9	22	(13)
White Cliffs	5	2	3	25	25	—
Other	26	24	2	73	63	10
Total distributions received from unconsolidated affiliates	$ 138	$ 98	$ 40	$ 302	$ 320	$ (18)

(1) For the three and nine months ended September 30, 2020, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by FEP, which reduced the Partnership's equity in earnings by $123 million and $208 million, respectively.

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

Segment Operating Results

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

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

- *Segment margin, operating expenses,* and *selling, general and administrative expenses*. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.
- *Unrealized gains or losses on commodity risk management activities and inventory valuation adjustments*. These are the unrealized amounts that are included in cost of products sold to calculate segment margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.
- *Non-cash compensation expense*. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative expenses. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.
- *Adjusted EBITDA related to unconsolidated affiliates*. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates.

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. Among the GAAP measures reported by the Partnership, the most directly comparable measure to segment margin is Segment Adjusted EBITDA; a reconciliation of segment margin to Segment Adjusted EBITDA is included in the following tables for each segment where segment margin is presented.

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.

Winter Storm Uri, which occurred in February 2021, resulted in one-time impacts to the Partnership’s Adjusted EBITDA and also affected the results of operations in certain segments, as discussed in segment analysis. The recognition of the impacts of Winter Storm Uri during the nine months ended September 30, 2021 required management to make certain estimates and assumptions, including estimates of expected credit losses and assumptions related to the resolution of disputes with counterparties with respect to certain purchases and sales of natural gas. The ultimate realization of credit losses and the resolution of disputed purchases and sales of natural gas could materially impact the Partnership’s financial condition and results of operations in future periods.

Intrastate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Natural gas transported (BBtu/d)	12,335	12,185	150	12,465	12,745	(280)
Withdrawals from storage natural gas inventory (BBtu)	2,350	10,315	(7,965)	32,038	15,380	16,658
Revenues	$ 1,217	$ 654	$ 563	$ 7,066	$ 1,763	$ 5,303
Cost of products sold	978	434	544	3,636	985	2,651
Segment margin	239	220	19	3,430	778	2,652
Unrealized (gains) losses on commodity risk management activities	(1)	23	(24)	(18)	(16)	(2)
Operating expenses, excluding non-cash compensation expense	(64)	(42)	(22)	(199)	(131)	(68)
Selling, general and administrative expenses, excluding non-cash compensation expense	(8)	(7)	(1)	(25)	(22)	(3)
Adjusted EBITDA related to unconsolidated affiliates	6	7	(1)	19	19	—
Other	—	2	(2)	2	2	—
Segment Adjusted EBITDA	$ 172	$ 203	$ (31)	$ 3,209	$ 630	$ 2,579

Volumes. For the three months ended September 30, 2021 compared to the same period last year, transported volumes increased primarily due to production increases in the Permian.

For the nine months ended September 30, 2021 compared to the same period last year, transported volumes decreased primarily due to the bankruptcy filing of a transportation customer, a contract step-down, and impacts of Winter Storm Uri.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Transportation fees	$ 162	$ 151	$ 11	$ 542	$ 460	$ 82
Natural gas sales and other (excluding unrealized gains and losses)	39	75	(36)	1,167	231	936
Retained fuel revenues (excluding unrealized gains and losses)	29	12	17	145	31	114
Storage margin (excluding unrealized gains and losses and fair value inventory adjustments)	8	5	3	1,558	40	1,518
Unrealized gains on commodity risk management activities and fair value inventory adjustments	1	(23)	24	18	16	2
Total segment margin	$ 239	$ 220	$ 19	$ 3,430	$ 778	$ 2,652

Segment Adjusted EBITDA. For the three months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation segment decreased due to the net effects of the following:

- a decrease of $36 million in realized natural gas sales and other primarily due to lower optimization volumes with shifts to long-term third-party contracts from the Permian to the Gulf Coast and lower spreads; and
- an increase of $22 million in operating expenses primarily due to increases of $9 million in cost of fuel consumption due to higher gas prices, $6 million in maintenance project costs, $3 million in employee related expenses, and $3 million in ad valorem taxes; partially offset by
- an increase of $11 million in transportation fees due to increased firm transportation volumes from the Permian;
- an increase of $17 million in retained fuel revenues primarily due to higher natural gas prices; and

- an increase of $3 million in realized storage margin due to higher storage optimization.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation segment increased due to the net effects of the following:

- an increase of $1.52 billion in realized storage margin due to higher physical storage margin from withdrawals during Winter Storm Uri;
- an increase of $936 million in realized natural gas sales and other primarily due to natural gas sales during Winter Storm Uri;
- an increase of $114 million in retained fuel revenues primarily due to higher natural gas prices during Winter Storm Uri; and
- an increase of $82 million in transportation fees due to revenues from Winter Storm Uri and demand volume ramp-ups from the Permian, partially offset by the expiration of certain contracts on our Regency Intrastate Gas System; partially offset by
- an increase of $68 million in operating expenses primarily due to increases of $45 million in cost of fuel consumption and $4 million in electricity costs, both of which were primarily due to higher gas prices related to Winter Storm Uri, as well as increases of $9 million in maintenance project costs, $7 million in employee related costs, and $3 million in outside services and material costs.

Interstate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Natural gas transported (BBtu/d)	9,917	10,387	(470)	9,769	10,422	(653)
Natural gas sold (BBtu/d)	16	15	1	18	16	2
Revenues	$ 418	$ 471	$ (53)	$ 1,350	$ 1,380	$ (30)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(152)	(147)	(5)	(429)	(429)	—
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(21)	(20)	(1)	(63)	(57)	(6)
Adjusted EBITDA related to unconsolidated affiliates	91	122	(31)	265	343	(78)
Other	(2)	(1)	(1)	(5)	(5)	—
Segment Adjusted EBITDA	$ 334	$ 425	$ (91)	$ 1,118	$ 1,232	$ (114)

Volumes. For the three and nine months ended September 30, 2021 compared to the same periods last year, transported volumes decreased primarily due to foundation shipper contract expirations and a shipper bankruptcy on our Tiger system, as well as lower utilization resulting from unfavorable market conditions on our Trunkline system.

Segment Adjusted EBITDA. For the three months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $53 million in revenues primarily due to a $37 million decline resulting from shipper contract expirations on our Tiger system and an $18 million decline due to a shipper bankruptcy during 2020 also on our Tiger system. In addition, transportation revenues decreased by $16 million on our Panhandle and Trunkline systems due to lower demand. These decreases were partially offset by an increase of $13 million in transportation revenue from our Rover system as a result of more favorable market conditions;
- an increase of $5 million in operating expenses primarily due to a $7 million increase from the revaluation of system gas, a $5 million increase in maintenance project costs, a $3 million increase in employee costs, and $2 million increase in ad valorem taxes; partially offset by a decrease in credit losses in the prior period;
- an increase of $1 million in selling, general and administrative expenses primarily due to higher allocated overhead costs and employee costs; and

- a decrease of $31 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to a $19 million decrease from our Fayetteville Express Pipeline joint venture as a result of the expiration of foundation shipper contracts, a $9 million decrease from our Citrus joint venture due to a contractual rate adjustment and a $3 million decrease from our Midcontinent Express Pipeline joint venture due to lower rates on short-term capacity.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $30 million in revenues primarily due to a $97 million decline resulting from shipper contract expirations on our Tiger system and a $37 million decline due to a shipper bankruptcy during 2020 also on our Tiger system. In addition, revenues decreased by $25 million on our Panhandle and Trunkline systems due to lower demand. These decreases were partially offset by increased transportation revenues of $30 million from our Rover system, and a $96 million increase in operational gas sales;
- an increase of $6 million in selling, general and administrative expenses primarily resulting from higher allocated overhead and employee costs; and
- a decrease of $78 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to a $57 million decrease from our Fayetteville Express Pipeline joint venture as a result of the expiration of foundation shipper contracts, a $13 million decrease from our Citrus joint venture due to higher project expenses and allocated costs as well as lower revenue resulting from a contractual rate adjustment, and an $8 million decrease from our Midcontinent Express Pipeline joint venture due to capacity sold at lower rates.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Gathered volumes (BBtu/d)	12,991	12,904	87	12,712	13,071	(359)
NGLs produced (MBbls/d)	667	635	32	624	616	8
Equity NGLs (MBbls/d)	37	32	5	35	35	—
Revenues	$ 2,919	$ 1,377	$ 1,542	$ 7,790	$ 3,565	$ 4,225
Cost of products sold	2,153	668	1,485	5,864	1,716	4,148
Segment margin	766	709	57	1,926	1,849	77
Operating expenses, excluding non-cash compensation expense	(191)	(169)	(22)	(551)	(528)	(23)
Selling, general and administrative expenses, excluding non-cash compensation expense	(28)	(21)	(7)	(80)	(67)	(13)
Adjusted EBITDA related to unconsolidated affiliates	8	9	(1)	23	23	—
Other	1	2	(1)	3	3	—
Segment Adjusted EBITDA	$ 556	$ 530	$ 26	$ 1,321	$ 1,280	$ 41

Volumes. Gathered volumes and NGL production increased during the three months ended September 30, 2021 compared to the same period last year primarily due to volume increases in the Permian, Ark-La-Tex, and South Texas regions, partially offset by volume declines in the Northeast and Mid-Continent/Panhandle regions.

Gathered volumes and NGL production decreased during the nine months ended September 30, 2021 compared to the same period last year primarily due to volume decreases in the South Texas, Mid-Continent/Panhandle, Northeast and North Texas regions partially offset by volume growth in the Permian and Ark-La-Tex regions.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Gathering and processing fee-based revenues	$ 535	$ 642	$ (107)	$ 1,555	$ 1,675	$ (120)
Non-fee-based contracts and processing	231	67	164	371	174	197
Total segment margin	$ 766	$ 709	$ 57	$ 1,926	$ 1,849	$ 77

Segment Adjusted EBITDA. For the three months ended September 30, 2021 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 $156 million in non-fee-based margin due to favorable NGL prices of $96 million and natural gas prices of $60 million; and
- an increase of $8 million in non-fee-based margin due to increased throughput in the Permian region and the ramp-up of recently completed assets in the Northeast region; partially offset by
- a decrease of $107 million in fee-based margin due to the recognition of $103 million related to the restructuring and assignment of certain gathering and processing contracts in the Ark-La-Tex region in the third quarter of 2020;
- an increase of $22 million in operating expenses due to an increase of $15 million in employee costs and $6 million in outside services; and
- an increase of $7 million in selling, general and administrative expenses due to higher allocated overhead costs.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 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 $319 million in non-fee-based margin due to favorable NGL prices of $197 million and natural gas prices of $122 million; and
- an increase of $21 million in non-fee-based margin due to increased throughput in the Permian region and the ramp-up of recently completed assets in the Northeast region; partially offset by
- a decrease of $143 million in non-fee-based margin due to the impacts of Winter Storm Uri;
- a decrease of $120 million in fee-based margin due to the recognition of $103 million related to the restructuring and assignment of certain gathering and processing contracts in the Ark-La-Tex region in the third quarter of 2020, as well as volume declines in the current period;
- an increase of $23 million in operating expenses due to an increase of $35 million in employee costs offset by a decrease of $9 million in outside services and $2 million in materials; and
- an increase of $13 million in selling, general and administrative expenses due to higher allocated overhead costs.

NGL and Refined Products Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
NGL transportation volumes (MBbls/d)	1,803	1,493	310	1,685	1,431	254
Refined products transportation volumes (MBbls/d)	526	460	66	500	460	40
NGL and refined products terminal volumes (MBbls/d)	1,237	850	387	1,156	813	343
NGL fractionation volumes (MBbls/d)	884	877	7	815	839	(24)
Revenues	$ 5,262	$ 2,623	$ 2,639	$ 13,774	$ 7,457	$ 6,317
Cost of products sold	4,347	1,712	2,635	11,035	4,916	6,119
Segment margin	915	911	4	2,739	2,541	198
Unrealized (gains) losses on commodity risk management activities	(2)	11	(13)	(71)	34	(105)
Operating expenses, excluding non-cash compensation expense	(207)	(162)	(45)	(573)	(475)	(98)
Selling, general and administrative expenses, excluding non-cash compensation expense	(27)	(20)	(7)	(82)	(64)	(18)
Adjusted EBITDA related to unconsolidated affiliates	26	22	4	75	63	12
Other	1	—	1	1	—	1
Segment Adjusted EBITDA	$ 706	$ 762	$ (56)	$ 2,089	$ 2,099	$ (10)

Volumes. For the three and nine months ended September 30, 2021 compared to the same periods last year, NGL transportation volumes increased primarily due to the initiation of service on our propane and ethane export pipelines into our Nederland Terminal in the fourth quarter of 2020, higher volumes from the Eagle Ford region and higher volumes on our Mariner East and West pipeline systems. For the nine months ended September 30, 2021 compared to the same period last year, the increase in NGL transportation volumes was partially offset by lower volumes caused by production interruptions, primarily in the Permian region, due to Winter Storm Uri during the first quarter of 2021.

Refined products transportation volumes increased for the three and nine months ended September 30, 2021 compared to the same periods last year due to recovery from COVID-19 related demand reduction in the prior period.

NGL and refined products terminal volumes increased for the three and nine months ended September 30, 2021 compared to the same periods last year primarily due to the previously mentioned start of new pipelines and refined product demand recovery.

Average fractionated volumes at our Mont Belvieu, Texas fractionation facility decreased for the nine months ended September 30, 2021 compared to the same period last year primarily due to lower NGL volumes feeding our Mont Belvieu fractionation facility as a result of production interruptions, primarily in the Permian region, due to Winter Storm Uri during the first quarter of 2021.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Transportation margin	$ 514	$ 494	$ 20	$ 1,495	$ 1,419	$ 76
Fractionators and refinery services margin	182	189	(7)	510	541	(31)
Terminal services margin	166	130	36	470	410	60
Storage margin	63	63	—	200	181	19
Marketing margin	(12)	46	(58)	(7)	24	(31)
Unrealized gains (losses) on commodity risk management activities	2	(11)	13	71	(34)	105
Total segment margin	$ 915	$ 911	$ 4	$ 2,739	$ 2,541	$ 198

Segment Adjusted EBITDA. For the three months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment decreased due to the net impacts of the following:

- a decrease of $58 million in marketing margin primarily due to a $36 million decrease in optimization gains and from the sale of NGL component products at our Mont Belvieu facility and a $19 million decrease in northeast blending and optimization primarily due to realized losses on financial instruments and increased costs related to renewable identification numbers (“RINs”), and a $6 million decrease due to optimization gains realized in 2020 as marketing prices increased. These decreases were partially offset by a $4 million increase in butane blending margin due to more favorable spreads and incremental gasoline blending in the third quarter of 2021;
- an increase of $45 million in operating expenses primarily due to a $21 million increase in utilities cost, a $16 million increase in employee related costs, a $6 million increase in materials and other associated costs to run the assets and a $2 million increase in allocated corporate overhead costs;
- an increase of $7 million in selling, general and administrative expenses primarily due to corporate cost reductions in 2020; and
- a decrease of $7 million in fractionators and refinery services margin primarily due to a $10 million decrease resulting from a slightly lower average rate achieved due to the increased utilization of our ethane optimization strategy. This decrease was partially offset by a $5 million increase in blending activity at our fractionation facility; partially offset by
- an increase of $36 million in terminal services margin primarily due to a $20 million increase in ethane export fees at our Nederland Terminal, an increase of $13 million in loading fees due to higher LPG export volumes at our Nederland Terminal and a $3 million increase at our refined product terminals due to higher throughput and timing of accounting adjustments;
- an increase of $20 million in transportation margin primarily due to a $30 million increase due to higher export volumes feeding into our Nederland Terminal, a $6 million increase from higher throughput on our Mariner pipeline system, and a $6 million increase in refined products transportation due to recovery from COVID-19 related demand reduction in the prior period and other refined products demand increases. These increases were partially offset by a $23 million decrease resulting from a slightly lower average rate achieved due to the increased utilization of our ethane optimization strategy; and
- an increase of $4 million in Adjusted EBITDA related to unconsolidated affiliates due to an increase primarily resulting from higher throughput on Explorer pipeline due to COVID-19 demand recovery.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment decreased due to the net impacts of the following:

- an increase of $98 million in operating expenses primarily due to a $54 million increase in utilities costs, $28 million increase in employee costs resulting primarily from corporate cost reductions in 2020 and an increase of $15 million in allocated corporate overhead costs;

- a decrease of $31 million in marketing margin primarily due to a $29 million decrease in northeast blending and optimization primarily due to realized losses on financial instruments and increased costs related to RINs and intrasegment charges of $28 million which were fully offset within our transportation margin. These decreases were partially offset by a $19 million increase in butane blending margin due to more favorable spreads and additional blending days granted by the EPA due to the Colonial Pipeline shutdown, and an $8 million increase due to inventory and other adjustments in the prior period;
- a decrease of $31 million in fractionators and refinery services margin primarily due to a $44 million decrease resulting from downtime on our various fractionators due to Winter Storm Uri in the first quarter of 2021 and a slightly lower average rate achieved due to increased utilization of our ethane optimization strategy. This decrease was partially offset by a $10 million increase from blending activity at our fractionators facility; and
- an increase of $18 million in selling, general and administrative expenses primarily due to corporate cost reductions in 2020; partially offset by
- an increase of $76 million in transportation margin primarily due to a $76 million increase due to higher export volumes feeding into our Nederland Terminal, a $39 million increase from higher throughput on our Mariner pipeline systems, intrasegment revenues of $28 million which are fully offset by a charge reflected in our marketing margin, and a $15 million increase in refined products transportation due to recovery from COVID-19 related demand reduction in the prior period and other refined products demand increases. These increases were partially offset by an $81 million decrease resulting from lower throughput across the various regions in Texas due to Winter Storm Uri related production outages and a slightly lower average rate achieved due to increased utilization of our ethane optimization strategy;
- an increase of $60 million in terminal services margin primarily due to a $49 million increase in ethane export fees at our Nederland Terminal, a $36 million increase in loading fees due to higher LPG export volumes at our Nederland Terminal, an $11 million increase due to higher throughput at our Marcus Hook Terminal and a $10 million increase due to higher throughput and storage at our refined product terminals due to recovery from COVID-19 related demand reduction in the prior period and other refined products demand increases. These increases were partially offset by a $44 million decrease resulting from an expiration of a third-party contract at our Nederland Terminal in the second quarter of 2020;
- an increase of $19 million in storage margin primarily due to fees generated from exported volumes; and
- an increase of $12 million in Adjusted EBITDA related to unconsolidated affiliates due to a $7 million increase primarily resulting from higher throughput on Explorer pipeline due to COVID-19 demand recovery and a $5 million increase from higher volumes on White Cliffs pipeline.

Crude Oil Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Crude transportation volumes (MBbls/d)	4,173	3,551	622	3,901	3,840	61
Crude terminals volumes (MBbls/d)	2,703	2,317	386	2,553	2,688	(135)
Revenues	$ 4,578	$ 2,850	$ 1,728	$ 12,498	$ 8,877	$ 3,621
Cost of products sold	3,918	2,096	1,822	10,520	6,704	3,816
Segment margin	660	754	(94)	1,978	2,173	(195)
Unrealized (gains) losses on commodity risk management activities	14	(1)	15	12	9	3
Operating expenses, excluding non-cash compensation expense	(142)	(112)	(30)	(414)	(401)	(13)
Selling, general and administrative expenses, excluding non-cash compensation expense	(44)	(28)	(16)	(102)	(82)	(20)
Adjusted EBITDA related to unconsolidated affiliates	7	9	(2)	15	32	(17)
Other	1	9	(8)	1	10	(9)
Segment Adjusted EBITDA	$ 496	$ 631	$ (135)	$ 1,490	$ 1,741	$ (251)

Volumes. For the three months ended September 30, 2021 compared to the same period last year, crude transportation volumes were higher on our Texas pipeline system and Bakken pipeline, driven by a recovery in crude oil production in these regions as a result of higher crude oil prices as well as a recovery in refinery utilization. Volumes on our Bayou Bridge pipeline were also higher, driven by more favorable crude oil differentials for shippers. Volumes also benefited from a full quarter of operations from our Cushing South pipeline. Crude terminal volumes were higher due to increased customer throughput activity at our Gulf Coast terminals.

For the nine months ended September 30, 2021 compared to the same period last year, crude transportation volumes were higher on our Bakken pipeline and Bayou Bridge pipelines, reflecting the continued recovery in crude oil production in North Dakota and more favorable crude oil differentials for shippers on Bayou Bridge. Volumes on our Texas pipeline system were slightly lower, primarily reflecting adverse weather negatively impacting volumes in the first quarter of 2021 and less favorable spreads for shippers to some markets in 2021. Crude terminal volumes were lower primarily due to reduced export demand.

Segment Adjusted EBITDA. For the three months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment decreased due to the net impacts of the following:

- a decrease of $79 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $133 million decrease from our crude oil acquisition and marketing business due to storage trading gains realized in the prior period, unfavorable crude inventory valuation adjustments, and less favorable pricing conditions impacting our Bakken to Gulf Coast trading operations, a $6 million decrease in throughput at our crude terminals primarily driven by lower export demand, and a $3 million decrease from our Texas crude pipeline system due to lower average tariff rates realized; partially offset by a $65 million increase from improved performance on our Bayou Bridge and Bakken pipelines;
- an increase of $30 million in operating expenses primarily due to higher volume-driven expenses and higher employee expenses;
- an increase of $16 million in selling, general and administrative expenses primarily due to legal expenses and higher overhead allocations to the crude segment as a result of assets acquired; and
- a decrease of $2 million in Adjusted EBITDA related to unconsolidated affiliates due to lower volumes on White Cliffs pipeline from lower crude oil production, partially offset by an increase in jet fuel sales by our joint ventures.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment decreased due to the net impacts of the following:

- a decrease of $192 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $152 million decrease from our Texas crude pipeline system due to lower utilization and lower average tariff rates realized, a $58 million decrease from our crude oil acquisition and marketing business primarily due to storage trading gains realized in the prior period and less favorable pricing conditions impacting our Bakken to Gulf Coast trading operations, partially offset by favorable crude inventory valuation adjustments and a $34 million decrease in throughput at our crude terminals primarily driven by reduced export demand; partially offset by an $18 million increase due to higher volumes on our Bayou Bridge pipeline and a $37 million increase due to higher volumes on our Bakken Pipeline;
- an increase of $13 million in operating expenses primarily due to higher volume-driven expenses and higher employee expenses;
- an increase of $20 million in selling, general and administrative expenses primarily due to legal expenses and higher overhead allocations to the crude segment as a result of assets acquired; and
- a decrease of $17 million in Adjusted EBITDA related to unconsolidated affiliates due to lower volumes on White Cliffs pipeline from lower crude oil production, partially offset by an increase in jet fuel sales by our joint ventures.

Investment in Sunoco LP

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Change	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Change
Revenues	$ 4,779	$ 2,805	$ 1,974	$ 12,642	$ 8,157	$ 4,485
Cost of products sold	4,472	2,497	1,975	11,631	7,383	4,248
Segment margin	307	308	(1)	1,011	774	237
Unrealized (gains) losses on commodity risk management activities	2	(6)	8	(5)	—	(5)
Operating expenses, excluding non-cash compensation expense	(85)	(84)	(1)	(236)	(265)	29
Selling, general and administrative expenses, excluding non-cash compensation expense	(23)	(24)	1	(67)	(76)	9
Adjusted EBITDA related to unconsolidated affiliates	3	2	1	7	7	—
Inventory valuation adjustments	(9)	(11)	2	(168)	126	(294)
Other	3	4	(1)	14	14	—
Segment Adjusted EBITDA	$ 198	$ 189	$ 9	$ 556	$ 580	$ (24)

The Investment in Sunoco LP segment reflects the consolidated results of Sunoco LP.

Segment Adjusted EBITDA. For the three months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment increased due to the net impacts of the following:

- an increase in the gross profit on motor fuel sales of $4 million primarily due to a 6.4% increase in gallons sold, partially offset by a 7.3% decrease in gross profit per gallon sold; and
- an increase in non-motor fuel sales of $5 million primarily due to increased credit card transactions, merchandise gross profit and franchise fee income.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment decreased due to the net impacts of the following:

- a decrease in the gross profit on motor fuel sales of $62 million primarily due to a 14.8% decrease in gross profit per gallon sold, partially offset by a 7.5% increase in gallons sold; partially offset by
- a decrease in operating expenses and selling, general and administrative expenses of $38 million primarily due to lower employee costs of and lower expected credit losses.

Investment in USAC

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Change	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Change
Revenues	$ 159	$ 161	$ (2)	$ 473	$ 509	$ (36)
Cost of products sold	19	20	(1)	61	62	(1)
Segment margin	140	141	(1)	412	447	(35)
Operating expenses, excluding non-cash compensation expense	(31)	(27)	(4)	(83)	(92)	9
Selling, general and administrative expenses, excluding non-cash compensation expense	(10)	(10)	—	(30)	(40)	10
Segment Adjusted EBITDA	$ 99	$ 104	$ (5)	$ 299	$ 315	$ (16)

The Investment in USAC segment reflects the consolidated results of USAC.

Segment Adjusted EBITDA. For the three months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment decreased due to the following:

- a decrease of $1 million in segment margin primarily due to slightly lower revenue generating horsepower; and
- an increase of $4 million in operating expenses primarily due to an increase in property taxes and expenses related to our vehicle fleet.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment decreased due to the net impacts of the following:

- a decrease of $35 million in segment margin primarily due to lower revenue generating horsepower; partially offset by
- a decrease of $9 million in operating expenses primarily driven by a $7 million decrease in direct labor expenses and a $4 million decrease primarily due to sales tax refunds received in 2021; and
- a decrease of $10 million in selling, general and administrative expenses primarily due to a $6 million decrease in the provision for expected credit losses, a $2 million decrease in severance charges related to the departure of an executive and a $2 million decrease in employee-related expenses.

All Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Change	2021	2020	Change
Revenues	$ 696	$ 367	$ 329	$ 2,784	$ 1,372	$ 1,412
Cost of products sold	652	318	334	2,464	1,110	1,354
Segment margin	44	49	(5)	320	262	58
Unrealized losses on commodity risk management activities	6	3	3	8	—	8
Operating expenses, excluding non-cash compensation expense	(29)	(35)	6	(118)	(100)	(18)
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(23)	10	(71)	(80)	9
Adjusted EBITDA related to unconsolidated affiliates	2	1	1	1	1	—
Other and eliminations	8	27	(19)	13	(21)	34
Segment Adjusted EBITDA	$ 18	$ 22	$ (4)	$ 153	$ 62	$ 91

Amounts reflected in our all other segment primarily include:

- our natural gas marketing operations;
- our wholly-owned natural gas compression operations;
- our investment in coal handling facilities; and
- our Canadian operations, which include natural gas gathering and processing assets.

Segment Adjusted EBITDA. For the three months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment decreased primarily due to the net impacts of the following:

- a decrease of $12 million due to the settlement of customer disputes related to prior period activity;
- a decrease of $7 million due to the revaluation of natural gas inventory; and
- a decrease of $2 million due to lower trading gains; partially offset by
- an increase of $5 million due to higher compressor sales and lower operating expenses in our compressor business;
- an increase of $2 million from Energy Transfer Canada due to the aggregate impact of multiples smaller changes; and
- an increase of $2 million due to lower utility expense.

Segment Adjusted EBITDA. For the nine months ended September 30, 2021 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment increased primarily due to the net impacts of the following:

- an increase of $60 million from power trading activities primarily due to short-term, favorable market conditions created by Winter Storm Uri in February of 2021;
- an increase of $17 million primarily due to revenues earned by our dual drive compression business under the Electric Reliability Council of Texas (“ERCOT”) responsive reserve program during Winter Storm Uri;
- an increase of $11 million due to improved margins at our dual drive compression business resulting from more favorable market pricing conditions;
- an increase of $12 million due to lower merger and acquisition expenses;
- an increase of $6 million from Energy Transfer Canada due to the aggregate impact of multiples smaller changes;
- an increase of $2 million due to a contract expiration at our natural resources business in 2020; and
- an increase of $2 million due to higher compressor sales and lower operating expenses in our compressor business; partially offset by
- a decrease of $22 million from 2020 insurance proceeds received on settled claims related to our MTBE litigation.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our ability to satisfy obligations and pay distributions to unitholders will depend on our 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 2021 to be within the following ranges (excluding capital expenditures related to our investments in Sunoco LP and USAC):

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 15	$ 25	$ 30	$ 35
Interstate transportation and storage [(1)]	50	75	115	120
Midstream	445	470	115	120
NGL and refined products transportation and services	650	725	110	120
Crude oil transportation and services [(1)]	275	325	90	100
All other (including eliminations)	90	115	45	55
Total capital expenditures	$ 1,525	$ 1,735	$ 505	$ 550

(1) Includes capital expenditures related to our proportionate ownership of the Bakken, Rover and Bayou Bridge pipeline projects and our proportionate ownership of the Orbit Gulf Coast NGL export project.

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 have included 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 expect to fund growth capital expenditures with proceeds of borrowings under our credit facilities, along with cash from operations.

Sunoco LP currently expects to invest approximately $150 million in growth capital expenditures and approximately $45 million on maintenance capital expenditures for the full year 2021.

USAC currently plans to spend approximately $20 million in maintenance capital expenditures and currently has budgeted between $30 million and $40 million in expansion capital expenditures for the full year 2021.

Cash Flows

Our 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"), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation, depletion and amortization expense and non-cash compensation expense. The increase in depreciation, depletion and amortization expense during the periods presented primarily resulted from construction and acquisition of assets, while changes in non-cash compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring, such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when 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 price risk management 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.

Nine months ended September 30, 2021 compared to nine months ended September 30, 2020. Cash provided by operating activities during 2021 was $9.42 billion compared to $5.46 billion for 2020, and net income was $5.46 billion for 2021 and net loss was $693 million for 2020. The difference between net income and net cash provided by operating activities for the nine months ended September 30, 2021 primarily consisted of net changes in operating assets and liabilities (net of effects of acquisitions) of $970 million and other non-cash items totaling $2.79 billion.

The non-cash activity in 2021 and 2020 consisted primarily of depreciation, depletion and amortization of $2.84 billion and $2.72 billion, respectively, non-cash compensation expense of $81 million and $93 million, respectively, favorable inventory valuation adjustments of $168 million and unfavorable inventory valuation adjustments of $126 million, respectively, deferred income taxes of $199 million and $159 million, respectively, losses on extinguishments of debt of $8 million and $62 million, respectively, and impairment losses of $11 million and $2.80 billion, respectively. Non-cash activity also included equity in earnings of unconsolidated affiliates of $191 million and $46 million in 2021 and 2020, respectively, and impairment of investment in an unconsolidated affiliate of $129 million in 2020.

Cash provided by operating activities includes cash distributions received from unconsolidated affiliates that are deemed to be paid from cumulative earnings, which distributions were $226 million in 2021 and $176 million in 2020.

Cash paid for interest, net of interest capitalized, was $1.57 billion and $1.47 billion for the nine months ended September 30, 2021 and 2020, respectively. Interest capitalized was $97 million and $163 million for the nine months ended September 30, 2021 and 2020, respectively.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid for acquisitions, capital expenditures, cash contributions to our joint ventures, and cash proceeds from sales or contributions of assets or businesses. In addition, distributions from equity investees are included in cash flows from investing activities if the distributions are deemed to be a return of the Partnership's investment. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Nine months ended September 30, 2021 compared to nine months ended September 30, 2020. Cash used in investing activities during 2021 was $1.91 billion compared to $3.86 billion for 2020. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2021 were $2.02 billion compared to $3.97 billion for 2020. Additional detail related to our capital expenditures is provided in the table below.

The following is a summary of capital expenditures (including only our proportionate share of the Bakken, Rover and Bayou Bridge pipeline projects and net of contributions in aid of construction costs) on an accrual basis for the nine months ended September 30, 2021:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$ 17	$ 24	$ 41
Interstate transportation and storage	24	72	96
Midstream	272	74	346
NGL and refined products transportation and services	508	77	585
Crude oil transportation and services	208	61	269
Investment in Sunoco LP	70	22	92
Investment in USAC	26	15	41
All other (including eliminations)	48	26	74
Total capital expenditures	$ 1,173	$ 371	$ 1,544

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions increase between the periods based on increases in the number of common units outstanding or increases in the distribution rate.

Nine months ended September 30, 2021 compared to nine months ended September 30, 2020. Cash used in financing activities during 2021 was $7.57 billion compared to $1.61 billion for 2020. During 2021, we had a net decrease in our debt level of $6.00 billion compared to a net increase of $358 million for 2020. In 2021 and 2020, we paid debt issuance costs of $3 million and $53 million, respectively. During 2021, we received $889 million from offerings of preferred units, and during 2020, our subsidiaries received $1.58 billion from offerings of preferred units.

In 2021 and 2020, we paid distributions of $1.38 billion and $2.40 billion, respectively, to our partners. In 2021 and 2020, we paid distributions of $1.15 billion and $1.28 billion, respectively, to noncontrolling interests. In 2021 and 2020, we paid distributions of $37 million to our redeemable noncontrolling interests. In addition, we received capital contributions of $114 million in cash from noncontrolling interests in 2021 compared to $203 million in cash from noncontrolling interests in 2020.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2021	December 31, 2020
ET Indebtedness:		
Senior Notes [1]	$ 36,454	$ 37,855
Term Loan [2]	—	2,000
Five-Year Credit Facility [2]	599	3,103
Subsidiary Indebtedness:		
Transwestern Senior Notes	400	400
Panhandle Senior Notes	235	235
Bakken Senior Notes [3]	2,500	2,500
Sunoco LP Senior Notes and lease-related obligations	2,701	3,139
USAC Senior Notes	1,475	1,475
HFOTCO Tax Exempt Notes	225	225
Revolving credit facilities:		
Sunoco LP Credit Facility	250	—
USAC Credit Facility	506	474
Energy Transfer Canada Revolving Credit Facility	81	57
Energy Transfer Canada Term Loan A	252	261
Energy Transfer Canada KAPS Facility	51	—
Other long-term debt	4	3
Net unamortized premiums, discounts, and fair value adjustments	(14)	(10)
Deferred debt issuance costs	(248)	(279)
Total debt	45,471	51,438
Less: current maturities of long-term debt	678	21
Long-term debt, less current maturities	$ 44,793	$ 51,417

(1) The balances presented above include senior notes that were formerly obligations of ETO prior to the Rollup Mergers discussed below and in "Recent Developments" above. As of March 31, 2021 and December 31, 2020, the outstanding principal amount of ETO senior notes was $36.4 billion and $37.8 billion, respectively. Beginning April 1, 2021, these senior notes are obligations of ET. A description of the ETO senior notes that were assumed by ET is included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2020.

(2) The Term Loan and Five-Year Credit Facility were previously obligations of ETO. Subsequent to the completion of the Rollup Mergers on April 1, 2021, these facilities are obligations of ET.

(3) The balance includes $650 million of 3.625% Senior Notes due April 2022 included in current maturities of long-term debt as of September 30, 2021.

Recent Transactions

In connection with the Rollup Mergers on April 1, 2021, ET entered into various supplemental indentures and assumed all the obligations of ETO under the respective indentures and credit agreements.

During the second quarter of 2021, ET repaid $1.5 billion on the Term Loan in part through proceeds from its Series H Preferred Unit issuance. During the third quarter of 2021, the Partnership repaid the remaining $500 million balance and terminated the Term Loan.

During the first quarter of 2021, ETO redeemed its $600 million aggregate principal amount of 4.40% senior notes due April 1, 2021 and its $800 million aggregate principal amount of 4.65% senior notes due June 1, 2021, using proceeds from the Five-Year Credit Facility.

During the third quarter of 2021, ET issued par call notices to redeem in full its $1.0 billion aggregate principal amount of 5.2% senior notes due February 1, 2022, and $900 million aggregate principal amount of 5.875% senior notes due March 1, 2022.

The Partnership expects to redeem both series of senior notes during the fourth quarter of 2021, utilizing proceeds from its Five-Year Credit Facility.

On October 20, 2021, Sunoco LP completed a private offering of $800 million in aggregate principal amount of 4.500% senior notes due 2030 (the "2030 Notes"). Sunoco LP used the proceeds from the private offering to fund a tender offer and repurchase all of its senior notes due 2026.

Credit Facilities and Commercial Paper

Term Loan

As a result of the Rollup Mergers, on April 1, 2021, ET assumed all of ETO's obligations in respect of its term loan credit agreement (the "Term Loan") and Sunoco Logistics Operations was released as a guarantor in respect of the Term Loan. The Partnership's Term Loan provides for a $2.00 billion three-year term loan credit facility. During the third quarter of 2021, the Term Loan was repaid in full and terminated.

Five-Year Credit Facility

As a result of the Rollup Mergers, on April 1, 2021, ET assumed all of ETO's obligations in respect of its revolving credit facility (the "Five-Year Credit Facility") and Sunoco Logistics Operations was released as a guarantor in respect of the Five-Year Credit Facility. The Partnership's Five-Year Credit Facility allows for unsecured borrowings up to $5.00 billion and matures on December 1, 2024. The Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $6.00 billion under certain conditions.

As of September 30, 2021, the Five-Year Credit Facility had $599 million of outstanding borrowings, of which $590 million consisted of commercial paper. The amount available for future borrowings was $4.37 billion, after accounting for outstanding letters of credit in the amount of $31 million. The weighted average interest rate on the total amount outstanding as of September 30, 2021 was 0.43%.

364-Day Facility

As a result of the Rollup Mergers, on April 1, 2021, ET assumed all of ETO's obligations in respect of its 364-day revolving credit facility (the "364-Day Facility") and Sunoco Logistics Operations was released as a guarantor in respect of the 364-Day Facility. The Partnership's 364-Day Facility allows for unsecured borrowings up to $1.00 billion and matures on November 26, 2021. As of September 30, 2021, the 364-Day Facility had no outstanding borrowings.

Sunoco LP Credit Facility

As of September 30, 2021, the Sunoco LP Credit Facility had $250 million of outstanding borrowings and $6 million in standby letters of credit and matures in July 2023. The amount available for future borrowings at September 30, 2021 was $1.24 billion. The weighted average interest rate on the total amount outstanding as of September 30, 2021 was 2.09%.

USAC Credit Facility

As of September 30, 2021, USAC had $506 million of outstanding borrowings under the credit agreement. As of September 30, 2021, USAC had $1.09 billion of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $114 million. The weighted average interest rate on the total amount outstanding as of September 30, 2021 was 2.96%.

Energy Transfer Canada Credit Facilities

As of September 30, 2021, the Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility had outstanding borrowings of C$320 million and C$103 million, respectively (US$252 million and US$81 million, respectively, at the September 30, 2021 exchange rate). As of September 30, 2021, the KAPS Facility had outstanding borrowings of C$65 million (US$51 million at the September 30, 2021 exchange rate).

Compliance with our Covenants

We and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of September 30, 2021.

CASH DISTRIBUTIONS

Cash Distributions Paid by ET

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

Cash Distributions on ET Common Units

Distributions declared and/or paid with respect to ET common units subsequent to December 31, 2020 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2020	February 8, 2021	February 19, 2021	$ 0.1525
March 31, 2021	May 11, 2021	May 19, 2021	0.1525
June 30, 2021	August 6, 2021	August 19, 2021	0.1525
September 30, 2021	November 5, 2021	November 19, 2021	0.1525

Cash Distributions on ET Preferred Units

As discussed in "Recent Developments", in connection with the Rollup Mergers, ETO's outstanding preferred units were converted into ET Preferred Units.

Distributions declared on the ET Preferred Units were as follows:

Period Ended	Record Date	Payment Date	Series A [(1)]	Series B [(1)]	Series C	Series D	Series E	Series F [(1)]	Series G [(1)]	Series H [(1)]
March 31, 2021	May 3, 2021	May 17, 2021	$ —	$ —	$ 0.4609	$ 0.4766	$ 0.4750	$ 33.75	$ 35.625	$ —
June 30, 2021	August 2, 2021	August 16, 2021	31.25	33.125	0.4609	0.4766	0.4750	—	—	—
September 30, 2021	November 1, 2021	November 15, 2021	—	—	0.4609	0.4766	0.4750	33.75	35.625	27.08 [(2)]

(1) Series A, Series B, Series F, Series G and Series H distributions are paid on a semi-annual basis.
(2) Represents initial prorated distribution.

Description of ET Preferred Units

A summary of the distribution and redemption rights associated with the ET Preferred Units is included in Note 9 in "Item 1. Financial Statements."

Cash Distributions Paid by Subsidiaries

The Partnership's consolidated financial statements include Sunoco LP and USAC, both of which are publicly traded master limited partnerships, as well as other less-than-wholly-owned, consolidated joint ventures. The following sections describe cash distributions made by our publicly traded subsidiaries, Sunoco LP and USAC, both of which are required by their respective partnership agreements to distribute all cash on hand (less appropriate reserves determined by the boards of directors of their respective general partners) subsequent to the end of each quarter.

Cash Distributions Paid by Sunoco LP

Distributions on Sunoco LP's units declared and/or paid by Sunoco LP subsequent to December 31, 2020 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2020	February 8, 2021	February 19, 2021	$ 0.8255
March 31, 2021	May 11, 2021	May 19, 2021	0.8255
June 30, 2021	August 6, 2021	August 19, 2021	0.8255
September 30, 2021	November 5, 2021	November 19, 2021	0.8255

Cash Distributions Paid by USAC

Distributions on USAC's units declared and/or paid by USAC subsequent to December 31, 2020 were as follows:

Quarter Ended	Record Date	Payment Date	Rate	
December 31, 2020	January 25, 2021	February 5, 2021	$	0.525
March 31, 2021	April 26, 2021	May 7, 2021		0.525
June 30, 2021	July 26, 2021	August 6, 2021		0.525
September 30, 2021	October 25, 2021	November 5, 2021		0.525

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules, and we believe the proper implementation and consistent application of the accounting rules are critical. We describe our significant accounting policies in Note 2 to our consolidated financial statements in the Partnership's Annual Report on Form 10-K filed with the SEC on February 19, 2021.

RECENT ACCOUNTING PRONOUNCEMENTS

Currently, there are no accounting pronouncements that have been issued, but not yet adopted, that are expected to have a material impact on the Partnership's financial position or results of operations.

FORWARD-LOOKING STATEMENTS

This quarterly report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. When used in this quarterly report, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend," "could," "believe," "may," "will" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations 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, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins they realize for their gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- impacts of world health events, including the COVID-19 pandemic;
- the possibility of cyber and malware attacks;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas, and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;

- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations;
- the costs and effects of legal and administrative proceedings; and
- the risks associated with a potential failure to successfully combine our business with that of Enable.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under “Part I - Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2020 filed with the SEC on February 19, 2021 and “Part II - Item 1A. Risk Factors” of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 filed with the SEC on August 5, 2021. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II - Item 7A included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2020 filed with the SEC on February 19, 2021, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2020. Since December 31, 2020, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Dollar amounts are presented in millions.

	September 30, 2021			December 31, 2020		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX [(1)]	(81,963)	$ 10	$ 1	(44,225)	$ 2	$ 5
Fixed Swaps/Futures	475	1	—	1,603	—	—
Power (Megawatt):						
Forwards	712,400	15	—	1,392,400	4	—
Futures	(640,800)	(7)	—	18,706	(1)	—
Options – Puts	290,400	—	—	519,071	—	—
Options – Calls	36,704	(1)	—	2,343,293	1	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(8,893)	(3)	—	(29,173)	—	1
Swing Swaps IFERC	(48,675)	4	1	11,208	(2)	—
Fixed Swaps/Futures	(45,588)	(55)	25	(53,575)	6	31
Forward Physical Contracts	(10,071)	3	—	(11,861)	4	5
NGLs (MBbls) – Forwards/Swaps	2,785	20	44	(5,840)	(100)	39
Refined Products (MBbls) – Futures	(3,272)	(3)	30	(2,765)	(8)	3
Crude (MBbls) – Forwards/Swaps	1,693	(13)	11	—	—	—
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(21,255)	2	—	(30,113)	(1)	—
Fixed Swaps/Futures	(21,255)	(20)	12	(30,113)	(6)	8

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

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

Interest Rate Risk

As of September 30, 2021, we and our subsidiaries had $2.51 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $25 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

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

		Notional Amount Outstanding	
Term	Type[(1)]	September 30, 2021	December 31, 2020
July 2021[(2)(3)]	Forward-starting to pay a fixed rate of 3.55% and receive a floating rate	$ —	$ 400
July 2022[(2)]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	400	400
July 2023[(2)]	Forward-starting to pay a fixed rate of 3.78% and receive a floating rate	200	—
July 2024[(2)]	Forward-starting to pay a fixed rate of 3.88% and receive a floating rate	200	—

(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.

(3) The July 2021 interest rate swaps were amended in June 2021.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $253 million as of September 30, 2021. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of senior management, including the Co-Chief Executive Officers ("Co-Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officers and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of September 30, 2021 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officers and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended September 30, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Annual Report on Form 10-K filed with the SEC on February 19, 2021 and Note 10 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer LP and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2021.

Additionally, we have received notices of violations and potential fines under various federal, state and local provisions relating to the discharge of materials into the environment or protection of the environment. While we believe that even if any one or more of the environmental proceedings listed below were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report governmental proceedings if we reasonably believe that such proceedings reasonably could result in monetary sanctions in excess of $300,000.

Pursuant to the instructions to Form 10-Q, matters disclosed in this Part II - Item 1 include any reportable legal proceeding (i) that has been terminated during the period covered by this report, (ii) that became a reportable event during the period covered by this report, or (iii) for which there has been a material development during the period covered by this report. For additional information, please see our Quarterly Reports filed for the quarters ended March 31, 2021 and June 30, 2021.

On June 4, 2019, the Oklahoma Corporation Commission's ("OCC") Transportation Division filed a complaint against SPLP seeking a penalty of up to $1 million related to a May 2018 rupture near Edmond, Oklahoma. The rupture occurred on the Noble to Douglas 8-inch pipeline in an area of external corrosion and caused the release of approximately fifteen barrels of crude oil. SPLP responded immediately to the release and remediated the surrounding environment and pipeline in cooperation with the OCC. The OCC filed the complaint alleging that SPLP failed to provide adequate cathodic protection to the pipeline causing the failure. SPLP entered into a settlement agreement with the OCC for a $500,000 penalty with an additional $500,000 suspended penalty to be voided if SPLP completes additional action items on the pipeline. SPLP had its final hearing with the OCC on August 18, 2021. On September 29, 2021, the OCC issued its Final Order closing the matter.

Energy Transfer received an Administrative Compliance Order from the New Mexico Environmental Department on August 28, 2020 to address the alleged noncompliance at its Jal 3 gas plant. The Compliance Order covered emission events that occurred January 1, 2017 through August 31, 2018. The Compliance Order includes an assessed civil penalty of approximately $4 million. On August 24, 2021, the New Mexico Environmental Department and Energy Transfer agreed to a Settlement Agreement and a Final Compliance Order that reduced the civil penalty to $1.3 million. Energy Transfer has completed its obligations under this Settlement Agreement and Final Compliance Order and the matter is now closed.

For additional information required in this Item, see disclosure under the headings "Litigation and Contingencies" and "Environmental Matters" in Note 10 to our consolidated financial statements included in "Item 1. Financial Statements," which information is incorporated by reference into this Item.

ITEM 1A. RISK FACTORS

The following risk factor should be read in conjunction with our risk factors described in "Part I - Item 1A. Risk Factors" in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2020 filed with the SEC on February 19, 2021.

Cybersecurity attacks, data breaches and other disruptions affecting us, or our service providers, could materially and adversely affect our business, operations, reputation, and financial results.

The security and integrity of our information technology infrastructure and physical assets are critical to our business and our ability to perform day-to-day operations and deliver services. In addition, in the ordinary course of our business, we collect, process, transmit and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, as well as personally identifiable information, in our data centers and on our networks. We also engage third parties, such as service providers and vendors, who provide a broad array of software, technologies, tools, and other products, services and functions (e.g., human resources, finance, data transmission, communications, risk, compliance, among others) that enable us to conduct, monitor and/or protect our business, operations, systems and data assets.

Our information technology and infrastructure, physical assets and data, may be vulnerable to unauthorized access, computer viruses, malicious attacks and other events (e.g., distributed denial of service ("DDoS") attacks, ransomware attacks) that are beyond our control. These events can result from malfeasance by external parties, such as hackers, or due to human error by our or our service providers' employees and contractors (e.g., due to social engineering or phishing attacks). In addition, the

COVID-19 pandemic has presented additional operational and cybersecurity risks to our information technology infrastructure and physical assets due to our providers' work-from-home arrangements.

We and certain of our service providers have, from time to time, been subject to cyberattacks and security incidents. The frequency and magnitude of cyberattacks is expected to increase and attackers are becoming more sophisticated. We may be unable to anticipate, detect or prevent future attacks, particularly as the methodologies used by attackers change frequently or are not recognized until launched, and we may be unable to investigate or remediate incidents because attackers are increasingly using techniques and tools designed to circumvent controls, to avoid detection, and to remove or obfuscate forensic evidence.

Breaches of our information technology infrastructure or physical assets, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position and results of operations. A successful cyberattack or other security incident could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or loss could result in legal claims or proceedings, regulatory investigations and enforcement, penalties and fines, increased costs for system remediation and compliance requirements, disruption of our operations, damage to our reputation, or loss of confidence in our products and services, any or all of which could have a material adverse effect on our business and results. We may be required to invest significant additional resources to comply with evolving cybersecurity regulations and to modify and enhance our information security and controls, and to investigate and remediate any security vulnerabilities. Any losses, costs or liabilities may not be covered by, or may exceed the coverage limits of, any or all of our applicable insurance policies.

ITEM 6. EXHIBITS

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

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of February 16, 2021, by and among Energy Transfer LP, Elk Merger Sub LLC, Elk GP Merger Sub LLC, Enable Midstream Partners, LP, Enable GP, LLC, solely for purposes of Section 2.1(a)(i) therein, LE GP, LLC, and, solely for purposes of Section 1.1(b)(i), CenterPoint Energy, Inc. (incorporated by reference to Exhibit 2.1 of Form 8-K (File No. 1-32740) filed February 16, 2021)
3.1	Certificate of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.2 of Form S-1 (File No. 333-128097) filed September 2, 2005)
3.2	Certificate of Amendment of Certificate of Limited Partnership of Energy Transfer Equity, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed October 19, 2018)
3.3	Third Amended Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated February 8, 2006 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed February 14, 2006)
3.4	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated November 1, 2006 (incorporated by reference to Exhibit 3.3.1 of Form 10-K (File No. 1-32740) filed November 29, 2006)
3.5	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated November 9, 2007 (incorporated by reference to Exhibit 3.3.2 of Form 8-K (File No. 1-32740) filed November 13, 2007)
3.6	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated May 26, 2010 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed June 2, 2010)
3.7	Amendment No. 4 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated December 23, 2013 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed December 27, 2013)
3.8	Amendment No. 5 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated March 8, 2016 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed March 9, 2016)
3.9	Amendment No. 6 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated October 19, 2018 (incorporated by reference to Exhibit 3.9 of Form 10-Q (File No. 1-32740) filed November 8, 2018)

Exhibit Number	Description
3.10	Amendment No. 7 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated August 6, 2019 (incorporated by reference to Exhibit 3.10 of Form 10-Q (File No. 1-32740) filed August 8, 2019)
3.11	Amendment No. 8 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated April 1, 2021 (incorporated by reference to Exhibit 2.2 of Form 8-K (File No. 1-32740) filed April 1, 2021)
3.12	Amendment No. 9 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated June 15, 2021 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed June 15, 2021)
22.1	Issuers and Guarantors of Registered Securities (incorporated by reference to Exhibit 22.1 of Form 10-Q (File No. 1-32740) filed August 5, 2021)
31.1*	Certification of Co-Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Co-Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Co-Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Co-Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.3**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets; (ii) our Consolidated Statements of Operations; (iii) our Consolidated Statements of Comprehensive Income (Loss); (iv) our Consolidated Statements of Partners' Capital; (v) our Consolidated Statements of Cash Flows; and (vi) the notes to our Consolidated Financial Statements
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)
*	Filed herewith
**	Furnished herewith
+	Denotes a management contract or compensatory agreement

SIGNATURE

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

ENERGY TRANSFER LP

By: LE GP, LLC, its general partner

Date: November 4, 2021

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

Exhibit 31.1

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

I, Marshall S. McCrea, III, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer LP;

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

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

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

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

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

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

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

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

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

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

Date: November 4, 2021

/s/ Marshall S. McCrea, III

Marshall S. McCrea, III
Co-Chief Executive Officer

Exhibit 31.2

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

I, Thomas E. Long, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer LP;

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

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

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

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

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

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

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

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

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

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

Date: November 4, 2021

/s/ Thomas E. Long

Thomas E. Long
Co-Chief Executive Officer

Exhibit 31.3

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

I, Bradford D. Whitehurst, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Transfer LP;

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

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

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

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

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

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

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

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

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

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

Date: November 4, 2021

/s/ Bradford D. Whitehurst
Bradford D. Whitehurst
Chief Financial Officer

Exhibit 32.1

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

In connection with the quarterly report of Energy Transfer LP (the "Partnership") on Form 10-Q for the quarter ended September 30, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Marshall S. McCrea, III, Co-Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: November 4, 2021

/s/ Marshall S. McCrea, III
Marshall S. McCrea, III
Co-Chief Executive Officer

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

Exhibit 32.2

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

In connection with the quarterly report of Energy Transfer LP (the “Partnership”) on Form 10-Q for the quarter ended September 30, 2021, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Thomas E. Long, Co-Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: November 4, 2021

/s/ Thomas E. Long
Thomas E. Long
Co-Chief Executive Officer

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

Exhibit 32.3

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

In connection with the quarterly report of Energy Transfer LP (the “Partnership”) on Form 10-Q for the quarter ended September 30, 2021, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Bradford D. Whitehurst, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: November 4, 2021

/s/ Bradford D. Whitehurst
Bradford D. Whitehurst
Chief Financial Officer

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