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, 2023

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 27, 2023, the registrant had 3,145,065,881 Common Units outstanding.

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ENERGY TRANSFER LP AND SUBSIDIARIES
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Definitions

References to the "Partnership" or "Energy Transfer" 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
BBtu	billion British thermal units
Citrus	Citrus, LLC, a 50/50 joint venture which owns Florida Gas Transmission Company, LLC, which owns the Florida Gas Transmission Pipeline
Dakota Access	Dakota Access, LLC, a non-wholly-owned subsidiary of Energy Transfer and/or Dakota Access Pipeline
Energy Transfer Canada	Energy Transfer Canada ULC, a non-wholly-owned subsidiary of Energy Transfer until its sale in August 2022
Energy Transfer 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, Series G Preferred Units and Series H Preferred Units
Energy Transfer R&M	Energy Transfer (R&M), LLC (formerly Sunoco (R&M), LLC)
ETC Sunoco	ETC Sunoco Holdings LLC (formerly Sunoco, Inc.), a wholly-owned subsidiary of Energy Transfer
ETO	Energy Transfer Operating, L.P., formerly a non-wholly-owned subsidiary of Energy Transfer until its merger into the Partnership in April 2021
Exchange Act	Securities Exchange Act of 1934, as amended
Explorer	Explorer Pipeline Company
FERC	Federal Energy Regulatory Commission
GAAP	accounting principles generally accepted in the United States of America
General Partner	LE GP, LLC, the general partner of Energy Transfer
HFOTCO	HFOTCO LLC, a wholly-owned subsidiary of Energy Transfer which owns the Houston Terminal
IFERC	Inside FERC's Gas Market Report
LIBOR	London Interbank Offered Rate
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP, a wholly-owned subsidiary of Energy Transfer and/or Panhandle Eastern Pipe Line
Partnership Agreement	Energy Transfer's Third Amended and Restated Agreement of Limited Partnership, as amended to date
PHMSA	Pipeline and Hazardous Materials Safety Administration
Rover	Rover Pipeline LLC, a non-wholly-owned subsidiary of Energy Transfer and/or Rover Pipeline
Sea Robin	Sea Robin Pipeline Company, LLC, a wholly-owned subsidiary of Energy Transfer
SEC	Securities and Exchange Commission
Series A Preferred Units	6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (currently a floating rate security)
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 (currently a floating rate security)
Series D Preferred Units	7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (currently a floating rate security)
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
SOFR	Secured overnight financing rate
SPLP	Sunoco Pipeline L.P., a wholly-owned subsidiary of Energy Transfer
Transwestern	Transwestern Pipeline Company, LLC, a wholly-owned subsidiary of Energy Transfer and/or Transwestern Pipeline
USAC	USA Compression Partners, LP, a publicly traded partnership and consolidated subsidiary of Energy Transfer
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, 2023	December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 514	$ 257
Accounts receivable, net	9,612	8,466
Accounts receivable from related companies	101	93
Inventories	2,590	2,461
Income taxes receivable	84	68
Derivative assets	14	10
Other current assets	508	726
Total current assets	13,423	12,081
Property, plant and equipment	109,411	105,996
Accumulated depreciation and depletion	(28,538)	(25,685)
Property, plant and equipment, net	80,873	80,311
Investments in unconsolidated affiliates	2,993	2,893
Non-current derivative assets	4	—
Lease right-of-use assets, net	820	819
Other non-current assets, net	1,690	1,558
Intangible assets, net	5,204	5,415
Goodwill	2,564	2,566
Total assets	$ 107,571	$ 105,643

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, 2023	December 31, 2022
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 7,997	$ 6,952
Accounts payable to related companies	7	17
Derivative liabilities	4	23
Operating lease current liabilities	45	45
Accrued and other current liabilities	3,696	3,329
Current maturities of long-term debt	1,006	2
Total current liabilities	12,755	10,368
Long-term debt, less current maturities	47,075	48,260
Non-current derivative liabilities	—	23
Non-current operating lease liabilities	775	798
Deferred income taxes	3,891	3,701
Other non-current liabilities	2,016	1,341
Commitments and contingencies		
Redeemable noncontrolling interests	498	493
Equity:		
Limited Partners:		
Preferred Unitholders	6,083	6,051
Common Unitholders	27,014	26,960
General Partner	(2)	(2)
Accumulated other comprehensive income	29	16
Total partners' capital	33,124	33,025
Noncontrolling interests	7,437	7,634
Total equity	40,561	40,659
Total liabilities and equity	$ 107,571	$ 105,643

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,	
	2023	2022	2023	2022
REVENUES:				
Refined product sales	$ 6,403	$ 6,647	$ 17,691	$ 20,043
Crude sales	6,587	5,773	17,298	17,758
NGL sales	3,760	4,823	11,409	15,828
Gathering, transportation and other fees	2,824	2,830	8,412	8,288
Natural gas sales	878	2,648	2,462	6,830
Other	287	218	782	628
Total revenues	20,739	22,939	58,054	69,375
COSTS AND EXPENSES:				
Cost of products sold	16,059	18,516	44,761	56,169
Operating expenses	1,105	973	3,224	2,982
Depreciation, depletion and amortization	1,107	1,030	3,227	3,104
Selling, general and administrative	234	361	700	802
Impairment losses and other	1	86	12	386
Total costs and expenses	18,506	20,966	51,924	63,443
OPERATING INCOME	2,233	1,973	6,130	5,932
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(632)	(577)	(1,892)	(1,714)
Equity in earnings of unconsolidated affiliates	103	68	286	186
Gains on interest rate derivatives	32	60	47	303
Non-operating litigation-related loss	(625)	—	(625)	—
Other, net	13	(120)	37	(117)
INCOME BEFORE INCOME TAX EXPENSE	1,124	1,404	3,983	4,590
Income tax expense	77	82	256	159
NET INCOME	1,047	1,322	3,727	4,431
Less: Net income attributable to noncontrolling interests	451	304	1,080	793
Less: Net income attributable to redeemable noncontrolling interests	12	12	39	37
NET INCOME ATTRIBUTABLE TO PARTNERS	584	1,006	2,608	3,601
General Partner's interest in net income	—	1	2	3
Preferred Unitholders' interest in net income	118	106	340	317
Common Unitholders' interest in net income	$ 466	$ 899	$ 2,266	$ 3,281
NET INCOME PER COMMON UNIT:				
Basic	$ 0.15	$ 0.29	$ 0.73	$ 1.06
Diluted	$ 0.15	$ 0.29	$ 0.72	$ 1.06

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Net income	$ 1,047	$ 1,322	$ 3,727	$ 4,431
Other comprehensive income (loss), net of tax:				
Change in value of available-for-sale securities	2	(4)	2	(13)
Actuarial gain related to pension and other postretirement benefit plans	—	—	—	7
Foreign currency translation adjustments	—	13	(5)	(6)
Change in other comprehensive income from unconsolidated affiliates	3	6	6	24
	5	15	3	12
Comprehensive income	1,052	1,337	3,730	4,443
Less: Comprehensive income attributable to noncontrolling interests	451	307	1,080	787
Less: Comprehensive income attributable to redeemable noncontrolling interests	12	12	39	37
Comprehensive income attributable to partners	$ 589	$ 1,018	$ 2,611	$ 3,619

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, 2022	$ 26,960	$ 6,051	$ (2)	$ 16	$ 7,634	$ 40,659
Distributions to partners	(920)	(80)	(1)	—	—	(1,001)
Distributions to noncontrolling interests	—	—	—	—	(441)	(441)
Capital contributions from noncontrolling interests	—	—	—	—	3	3
Other comprehensive loss, net of tax	—	—	—	(3)	—	(3)
Other, net	14	—	—	—	4	18
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,003	109	1	—	321	1,434
Balance, March 31, 2023	27,057	6,080	(2)	13	7,521	40,669
Distributions to partners	(942)	(151)	(1)	—	—	(1,094)
Distributions to noncontrolling interests	—	—	—	—	(421)	(421)
Other comprehensive income, net of tax	—	—	—	1	—	1
Lotus Midstream acquisition	574	—	—	—	—	574
Other, net	1	—	—	10	3	14
Net income, excluding amounts attributable to redeemable noncontrolling interests	797	113	1	—	308	1,219
Balance, June 30, 2023	27,487	6,042	(2)	24	7,411	40,962
Distributions to partners	(952)	(77)	—	—	—	(1,029)
Distributions to noncontrolling interests	—	—	—	—	(428)	(428)
Other comprehensive income, net of tax	—	—	—	5	—	5
Other, net	13	—	—	—	3	16
Net income, excluding amounts attributable to redeemable noncontrolling interests	466	118	—	—	451	1,035
Balance, September 30, 2023	$ 27,014	$ 6,083	$ (2)	$ 29	$ 7,437	$ 40,561

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	Preferred Unitholders	General Partner	AOCI	Noncontrolling Interests	Total
Balance, December 31, 2021	$ 25,230	$ 6,051	$ (4)	$ 23	$ 8,045	$ 39,345
Distributions to partners	(528)	(80)	—	—	—	(608)
Distributions to noncontrolling interests	—	—	—	—	(307)	(307)
Capital contributions from noncontrolling interests	—	—	—	—	373	373
Other comprehensive income, net of tax	—	—	—	20	5	25
Other, net	17	—	—	—	10	27
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,162	106	1	—	205	1,474
Balance, March 31, 2022	25,881	6,077	(3)	43	8,331	40,329
Distributions to partners	(603)	(131)	(1)	—	—	(735)
Distributions to noncontrolling interests	—	—	—	—	(446)	(446)
Capital contributions from noncontrolling interests	—	—	—	—	24	24
Other comprehensive loss, net of tax	—	—	—	(14)	(14)	(28)
Other, net	9	—	—	—	2	11
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,220	105	1	—	284	1,610
Balance, June 30, 2022	26,507	6,051	(3)	29	8,181	40,765
Distributions to partners	(694)	(80)	(1)	—	—	(775)
Distributions to noncontrolling interests	—	—	—	—	(424)	(424)
Capital contributions from noncontrolling interests	—	—	—	—	7	7
Energy Transfer Canada sale	—	—	—	(9)	(337)	(346)
Other comprehensive loss, net of tax	—	—	—	12	3	15
Other, net	13	—	—	—	3	16
Net income, excluding amounts attributable to redeemable noncontrolling interests	899	106	1	—	304	1,310
Balance, September 30, 2022	$ 26,725	$ 6,077	$ (3)	$ 32	$ 7,737	$ 40,568

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, 2023	Nine Months Ended September 30, 2022
OPERATING ACTIVITIES:		
Net income	$ 3,727	$ 4,431
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	3,227	3,104
Deferred income taxes	187	158
Inventory valuation adjustments	(113)	(81)
Non-cash compensation expense	99	88
Impairment losses and other	12	386
Distributions on unvested awards	(47)	(37)
Equity in earnings of unconsolidated affiliates	(286)	(186)
Distributions from unconsolidated affiliates	286	182
Other non-cash	(15)	(120)
Net change in operating assets and liabilities, net of effects of acquisitions and divestitures	1,182	(212)
Net cash provided by operating activities	8,259	7,713
INVESTING ACTIVITIES:		
Cash paid for Lotus Midstream acquisition, net of cash received	(930)	—
Cash paid for other acquisitions, net of cash received	(111)	(1,062)
Capital expenditures, excluding allowance for equity funds used during construction	(2,430)	(2,493)
Contributions in aid of construction costs	38	50
Contributions to unconsolidated affiliates	(5)	—
Distributions from unconsolidated affiliates in excess of cumulative earnings	45	66
Proceeds from sale of Energy Transfer Canada interest	—	302
Proceeds from sales of other assets	31	60
Other, net	1	—
Net cash used in investing activities	(3,361)	(3,077)
FINANCING ACTIVITIES:		
Proceeds from borrowings	22,912	19,400
Repayments of debt	(23,095)	(21,110)
Capital contributions from noncontrolling interests	3	404
Distributions to partners	(3,124)	(2,118)
Distributions to noncontrolling interests	(1,290)	(1,177)
Distributions to redeemable noncontrolling interests	(37)	(37)
Debt issuance costs	(12)	(9)
Other, net	2	1
Net cash used in financing activities	(4,641)	(4,646)
Increase (decrease) in cash and cash equivalents	257	(10)
Cash and cash equivalents, beginning of period	257	336
Cash and cash equivalents, end of period	$ 514	$ 326

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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 "Energy Transfer").

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, 2022, filed with the SEC on February 17, 2023. 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 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. The Partnership owns the general partner interest, incentive distribution rights and 28.5 million common units of Sunoco LP, and the general partner interests and 46.1 million common units of USAC.

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

Pending Crestwood Acquisition

On August 16, 2023, the Partnership announced its entry into a definitive merger agreement to acquire Crestwood Equity Partners LP ("Crestwood"). Under the terms of the merger agreement, Crestwood's common unitholders will receive 2.07 Energy Transfer common units for each Crestwood common unit. Crestwood owns gathering and processing assets located in the Williston, Delaware and Powder River basins. On October 30, 2023, a majority of Crestwood's unitholders voted to approve the merger. The transaction is expected to close on November 3, 2023, subject to customary closing conditions.

Lotus Midstream Acquisition

On May 2, 2023, Energy Transfer acquired Lotus Midstream Operations, LLC ("Lotus Midstream") for total consideration of $1.50 billion, including working capital. Consideration included $930 million in cash and approximately 44.5 million newly issued Energy Transfer common units, which had an aggregate acquisition-date fair value of $574 million. Lotus Midstream owns and operates Centurion Pipeline Company LLC, an integrated crude midstream platform located in the Permian Basin.

The following table summarizes the assumed allocation of the purchase price among the assets acquired and liabilities assumed:

	At May 2, 2023
Total current assets	$ 61
Property, plant and equipment, net	1,263
Investments in unconsolidated affiliates	138
Lease right-of-use assets, net	10
Other non-current assets	4
Intangible assets, net	75
Total assets	1,551
Total current liabilities	27
Other non-current liabilities	16
Total liabilities	43
Total consideration	1,508
Cash received	4
Total consideration, net of cash received	$ 1,504

Sunoco LP's Acquisition

On May 1, 2023, Sunoco LP completed the acquisition of 16 refined product terminals located across the East Coast and Midwest from Zenith Energy for $111 million, including working capital. The purchase price was primarily allocated to property and equipment.

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, 2023 or December 31, 2022.

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,	
	2023	2022
Accounts receivable	$ (1,125)	$ (999)
Accounts receivable from related companies	(8)	17
Inventories	(3)	(287)
Other current assets	208	(176)
Other non-current assets, net	(135)	106
Accounts payable	1,076	599
Accounts payable to related companies	(12)	1
Accrued and other current liabilities	562	585
Other non-current liabilities	669	254
Derivative assets and liabilities, net	(50)	(312)
Net change in operating assets and liabilities, net of effects of acquisitions and divestitures	$ 1,182	$ (212)

Non-cash investing and financing activities were as follows:

	Nine Months Ended September 30,	
	2023	2022
Accrued capital expenditures	$ 354	$ 454
Lease assets obtained in exchange for new lease liabilities	26	37
Distribution reinvestment	70	42

4. INVENTORIES

Inventories consisted of the following:

	September 30, 2023	December 31, 2022
Natural gas, NGLs and refined products	$ 1,951	$ 1,802
Crude oil	169	246
Spare parts and other	470	413
Total inventories	$ 2,590	$ 2,461

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, 2023 and December 31, 2022, the carrying value of Sunoco LP’s fuel inventory included lower of cost or market reserves of $3 million and $116 million, respectively. For the three and nine months ended September 30, 2023 and 2022, the Partnership’s consolidated income statements did not include any material amounts of income from the liquidation of Sunoco LP’s LIFO fuel inventory. For the three months ended September 30, 2023 and 2022, the Partnership’s cost of products sold included favorable inventory adjustments of $141 million and unfavorable inventory adjustments of $40 million, respectively, related to Sunoco LP’s LIFO inventory. For the nine months ended September 30, 2023 and 2022, the Partnership’s cost of products sold included favorable inventory adjustments of $113 million and favorable inventory adjustments of $81 million, respectively, related to Sunoco LP’s LIFO inventory.

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 options transacted through a clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. The valuation methodologies employed for our interest rate derivatives do not necessitate material judgment, and the inputs are observed from actively quoted public markets and therefore are categorized in Level 2. Level 3 inputs are unobservable. During the nine months ended September 30, 2023, 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, 2023 and December 31, 2022 based on inputs used to derive their fair values:

		Fair Value Measurements at September 30, 2023	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$ 14	$ —	$ 14
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 3	$ 3	$ —
Swing Swaps IFERC	4	4	—
Fixed Swaps/Futures	28	28	—
Forward Physical Contracts	3	—	3
Power:			
Forwards	46	—	46
Futures	6	6	—
NGLs – Forwards/Swaps	256	256	—
Refined Products – Futures	27	27	—
Crude – Forwards/Swaps	32	32	—
Total commodity derivatives	405	356	49
Other non-current assets	28	18	10
Total assets	$ 447	$ 374	$ 73
Liabilities:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ (10)	$ (10)	$ —
Swing Swaps IFERC	(5)	(5)	—
Fixed Swaps/Futures	(2)	(2)	—
Power:			
Forwards	(45)	—	(45)
Futures	(5)	(5)	—
NGLs – Forwards/Swaps	(306)	(306)	—
Refined Products – Futures	(35)	(35)	—
Crude – Forwards/Swaps	(41)	(41)	—
Total commodity derivatives	(449)	(404)	(45)
Total liabilities	$ (449)	$ (404)	$ (45)

	Fair Value Total	Fair Value Measurements at December 31, 2022	
		Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 60	$ 60	$ —
Swing Swaps IFERC	75	75	—
Fixed Swaps/Futures	113	113	—
Forward Physical Contracts	10	—	10
Power:			
Forwards	52	—	52
Futures	3	3	—
NGLs – Forwards/Swaps	317	317	—
Refined Products – Futures	20	20	—
Crude – Forwards/Swaps	38	38	—
Total commodity derivatives	688	626	62
Other non-current assets	27	18	9
Total assets	$ 715	$ 644	$ 71
Liabilities:			
Interest rate derivatives	$ (23)	$ —	$ (23)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(25)	(25)	—
Swing Swaps IFERC	(12)	(12)	—
Fixed Swaps/Futures	(4)	(4)	—
Forward Physical Contracts	(2)	—	(2)
Power:			
Forwards	(51)	—	(51)
Futures	(3)	(3)	—
NGLs – Forwards/Swaps	(358)	(358)	—
Refined Products – Futures	(59)	(59)	—
Crude – Forwards/Swaps	(12)	(12)	—
Total commodity derivatives	(526)	(473)	(53)
Total liabilities	$ (549)	$ (473)	$ (76)

The aggregate estimated fair value and carrying amount of our consolidated debt obligations as of September 30, 2023 were $44.60 billion and $48.08 billion, respectively. As of December 31, 2022, the aggregate fair value and carrying amount of our consolidated debt obligations were $45.42 billion and $48.26 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 PER COMMON UNIT

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Net income	$ 1,047	$ 1,322	$ 3,727	$ 4,431
Less: Net income attributable to noncontrolling interests	451	304	1,080	793
Less: Net income attributable to redeemable noncontrolling interests	12	12	39	37
Net income, net of noncontrolling interests	584	1,006	2,608	3,601
Less: General Partner's interest in net income	—	1	2	3
Less: Preferred Unitholders' interest in net income	118	106	340	317
Common Unitholders' interest in net income	$ 466	$ 899	$ 2,266	$ 3,281
Basic Income per Common Unit:				
Weighted average common units	3,144.0	3,087.6	3,122.3	3,085.6
Basic income per common unit	$ 0.15	$ 0.29	$ 0.73	$ 1.06
Diluted Income per Common Unit:				
Common Unitholders' interest in net income	$ 466	$ 899	$ 2,266	$ 3,281
Dilutive effect of equity-based compensation of subsidiaries [(1)]	1	—	2	2
Diluted income attributable to Common Unitholders	$ 465	$ 899	$ 2,264	$ 3,279
Weighted average common units	3,144.0	3,087.6	3,122.3	3,085.6
Dilutive effect of unvested restricted unit awards [(1)]	23.7	21.0	23.6	20.8
Weighted average common units, assuming dilutive effect of unvested restricted unit awards	3,167.7	3,108.6	3,145.9	3,106.4
Diluted income per common unit	$ 0.15	$ 0.29	$ 0.72	$ 1.06

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

7. DEBT OBLIGATIONS

Recent Transactions

Senior Notes

On November 1, 2023, the Partnership redeemed $600 million aggregate principal amount of its 4.50% Senior Notes due November 1, 2023 using proceeds from the senior notes offering discussed in the following paragraph.

In October 2023, the Partnership issued $1.00 billion aggregate principal amount of 6.05% Senior Notes due 2026, $500 million aggregate principal amount of 6.10% Senior Notes due 2028, $1.00 billion aggregate principal amount of 6.40% Senior Notes due 2030 and $1.50 billion aggregate principal amount of 6.55% Senior Notes due 2033. The Partnership intends to use the net proceeds to refinance existing indebtedness, including borrowings under its Five-Year Credit Facility (defined below) and for general partnership purposes.

In the third quarter of 2023, the Partnership redeemed $500 million aggregate principal amount of its 4.20% Senior Notes due September 2023 using proceeds from its Five-Year Credit Facility.

In the first quarter of 2023, the Partnership redeemed $350 million aggregate principal amount of its 3.45% Senior Notes due January 2023, $800 million aggregate principal amount of its 3.60% Senior Notes due February 2023 and $1.00 billion aggregate principal amount of its 4.25% Senior Notes due March 2023 using proceeds from its Five-Year Credit Facility.

HFOTCO Debt

In May 2023, the Partnership refinanced all of the $225 million outstanding principal amount of HFOTCO tax-exempt bonds with new 10-year tax-exempt bonds. The new bonds, which were issued through the Harris County Industrial Development Corporation and are obligations of Energy Transfer, accrue interest at a fixed rate of 4.05% and are mandatorily redeemable in 2033. Upon redemption, these tax-exempt bonds may be remarketed on different terms through final maturity of November 1, 2050.

Sunoco LP Senior Notes Offering

In September 2023, Sunoco LP issued $500 million aggregate principal amount of 7.00% senior notes due 2028 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP's existing borrowings under its credit facility.

Current Maturities of Long-Term Debt

As of September 30, 2023, current maturities of long-term debt reflected on the Partnership's consolidated balance sheet included $1.00 billion of senior notes issued by the Bakken Pipeline entities, which mature in April 2024.

Credit Facilities and Commercial Paper

Five-Year Credit Facility

The Partnership's revolving credit facility (the "Five-Year Credit Facility") allows for unsecured borrowings up to $5.00 billion and matures in April 2027. The Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $7.00 billion under certain conditions.

As of September 30, 2023, the Five-Year Credit Facility had $2.85 billion of outstanding borrowings, of which $1.55 billion consisted of commercial paper. The amount available for future borrowings was $2.12 billion, after accounting for outstanding letters of credit in the amount of $32 million. The weighted average interest rate on the total amount outstanding as of September 30, 2023 was 6.29%.

Sunoco LP Credit Facility

As of September 30, 2023, Sunoco LP's credit facility had $647 million of outstanding borrowings and $6 million in standby letters of credit and matures in April 2027. The amount available for future borrowings at September 30, 2023 was $847 million. The weighted average interest rate on the total amount outstanding as of September 30, 2023 was 7.34%.

USAC Credit Facility

As of September 30, 2023, USAC's credit facility, which matures in December 2026, had $813 million of outstanding borrowings and no outstanding letters of credit. As of September 30, 2023, USAC had $787 million of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $434 million. The weighted average interest rate on the total amount outstanding as of September 30, 2023 was 7.99%.

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, 2023. For the quarter ended September 30, 2023, our leverage ratio, as calculated pursuant to the covenant related to our Five-Year Credit Facility, was 3.11x.

8. REDEEMABLE NONCONTROLLING INTERESTS

Certain redeemable noncontrolling interests in the Partnership's subsidiaries were reflected as mezzanine equity on the consolidated balance sheets. Redeemable noncontrolling interests as of September 30, 2023 and December 31, 2022 included a balance of $477 million related to the USAC Series A preferred units. Redeemable noncontrolling interests also included a balance of $21 million as of September 30, 2023 and $16 million as of December 31, 2022 related to noncontrolling interest holders in one of the Partnership's consolidated subsidiaries that have the option to sell their interests to the Partnership.

9. EQUITY

Energy Transfer Common Units

Changes in Energy Transfer common units during the nine months ended September 30, 2023 were as follows:

	Number of Units
Number of common units at December 31, 2022	3,094.4
Common units issued under the distribution reinvestment plan	5.5
Common units issued for Lotus Midstream acquisition	44.5
Common units vested under equity incentive plans and other	0.7
Number of common units at September 30, 2023	3,145.1

Energy Transfer Repurchase Program

During the nine months ended September 30, 2023, Energy Transfer did not repurchase any of its common units under its current buyback program. As of September 30, 2023, $880 million remained available to repurchase under the current program.

Energy Transfer Distribution Reinvestment Program

During the nine months ended September 30, 2023, distributions of $70 million were reinvested under the distribution reinvestment program. As of September 30, 2023, a total of 6 million Energy Transfer common units remained available to be issued under the existing registration statement in connection with the distribution reinvestment program.

Cash Distributions on Energy Transfer Common Units

Distributions declared and/or paid with respect to Energy Transfer common units subsequent to December 31, 2022 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2022	February 7, 2023	February 21, 2023	$ 0.3050
March 31, 2023	May 8, 2023	May 22, 2023	0.3075
June 30, 2023	August 14, 2023	August 21, 2023	0.3100
September 30, 2023	October 30, 2023	November 20, 2023	0.3125

Energy Transfer Preferred Units

As of September 30, 2023 and December 31, 2022, Energy Transfer’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, 1,484,780 Series G Preferred Units and 900,000 Series H Preferred Units.

The following table summarizes changes in the Energy Transfer Preferred Units:

	Preferred Unitholders								
	Series A	Series B	Series C	Series D	Series E	Series F	Series G	Series H	Total
Balance, December 31, 2022	$ 958	$ 556	$ 440	$ 434	$ 786	$ 496	$ 1,488	$ 893	$ 6,051
Distributions to partners	(30)	(18)	(8)	(9)	(15)	—	—	—	(80)
Net income	18	9	8	9	15	8	27	15	109
Balance, March 31, 2023	946	547	440	434	786	504	1,515	908	6,080
Distributions to partners	(21)	—	(8)	(9)	(15)	(16)	(53)	(29)	(151)
Net income	22	9	9	9	15	8	26	15	113
Balance, June 30, 2023	947	556	441	434	786	496	1,488	894	6,042
Distributions to partners	(22)	(20)	(12)	(8)	(15)	—	—	—	(77)
Net income	23	10	11	10	15	8	27	14	118
Balance, September 30, 2023	$ 948	$ 546	$ 440	$ 436	$ 786	$ 504	$ 1,515	$ 908	$ 6,083

	Preferred Unitholders								
	Series A	Series B	Series C	Series D	Series E	Series F	Series G	Series H	Total
Balance, December 31, 2021	$ 958	$ 556	$ 440	$ 434	$ 786	$ 496	$ 1,488	$ 893	$ 6,051
Distributions to partners	(30)	(18)	(8)	(9)	(15)	—	—	—	(80)
Net income	15	9	8	9	15	8	27	15	106
Balance, March 31, 2022	943	547	440	434	786	504	1,515	908	6,077
Distributions to partners	—	—	(8)	(9)	(15)	(16)	(53)	(30)	(131)
Net income	15	9	8	9	15	8	26	15	105
Balance, June 30, 2022	958	556	440	434	786	496	1,488	893	6,051
Distributions to partners	(30)	(18)	(8)	(9)	(15)	—	—	—	(80)
Net income	15	9	8	9	15	8	27	15	106
Balance, September 30, 2022	$ 943	$ 547	$ 440	$ 434	$ 786	$ 504	$ 1,515	$ 908	$ 6,077

Cash Distributions on Energy Transfer Preferred Units

Distributions declared on the Energy Transfer Preferred Units were as follows:

Period Ended	Record Date	Payment Date	Series A[(1)]	Series B[(2)]	Series C[(1)]	Series D[(1)]	Series E	Series F[(2)]	Series G[(2)]	Series H[(2)]
December 31, 2022	February 1, 2023	February 15, 2023	$ 31.250	$ 33.125	$ 0.4609	$ 0.4766	$ 0.475	$ —	$ —	$ —
March 31, 2023	May 1, 2023	May 15, 2023	21.982	—	0.4609	0.4766	0.475	33.750	35.625	32.500
June 30, 2023	August 1, 2023	August 15, 2023	23.891	33.125	0.6294	0.4766	0.475	—	—	—
September 30, 2023	November 1, 2023	November 15, 2023	24.672	—	0.6489	0.6622	0.475	33.750	35.625	32.500

(1) See additional information on Series A, Series C and Series D distributions below.

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

Prior to February 15, 2023, distributions on the Series A Preferred Units accrued at a fixed rate of 6.250% per annum of the liquidation preference of $1,000. Beginning February 15, 2023 to, but excluding, August 15, 2023, the Series A Preferred Units accrued a floating distribution rate set each quarterly distribution period at a percentage of the $1,000 liquidation preference equal to the then-current three-month LIBOR plus a spread of 4.028% per annum. On and after August 15, 2023, the floating distribution rate on the Series A Preferred Units is based on the three-month SOFR, plus a tenor spread adjustment of 0.26161%, plus 4.028% per annum. Distributions on Series A Preferred Units were previously payable semiannually in arrears until February 15, 2023, and, after February 15, 2023, quarterly in arrears, when, as, and if declared by our General Partner out of legally available funds for such purpose.

Prior to May 15, 2023, distributions on the Series C Preferred Units accrued at a fixed rate of 7.375% per annum of the liquidation preference of $25. Beginning May 15, 2023 to, but excluding, August 15, 2023, the Series C Preferred Units accrued a floating distribution rate set each quarterly distribution period at a percentage of the $25 liquidation preference equal to the then-current three-month LIBOR plus a spread of 4.530% per annum. On and after August 15, 2023, the floating distribution rate on the Series C Preferred Units is based on the three-month SOFR, plus a tenor spread adjustment of 0.26161%, plus 4.530% per annum.

Prior to August 15, 2023, distributions on the Series D Preferred Units accrued at a fixed rate of 7.625% per annum of the liquidation preference of $25. On and after August 15, 2023, the Series D Preferred Units accrue a floating distribution rate set each quarterly distribution period at a percentage of the $25 liquidation preference equal to the three-month SOFR, plus a tenor spread adjustment of 0.26161%, plus 4.738% per annum.

Distributions on the Series B Preferred Units and Series E Preferred Units are scheduled to begin accruing at a floating rate as follows:

	Beginning of floating rate period	Applicable Spread	Tenor spread adjustment	Floating rate
Series B Preferred Units	February 15, 2028	4.155 %	0.26161 %	Three-month SOFR
Series E Preferred Units	May 15, 2024	5.161 %	0.26161 %	Three-month SOFR

Noncontrolling Interests

The Partnership's consolidated financial statements also include noncontrolling interests in Sunoco LP and USAC, both of which are master limited partnerships, as well as other non-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 common units declared and/or paid by Sunoco LP subsequent to December 31, 2022 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2022	February 7, 2023	February 21, 2023	$ 0.8255
March 31, 2023	May 8, 2023	May 22, 2023	0.8420
June 30, 2023	August 14, 2023	August 21, 2023	0.8420
September 30, 2023	October 30, 2023	November 20, 2023	0.8420

USAC Cash Distributions

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2022 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2022	January 23, 2023	February 3, 2023	$ 0.525
March 31, 2023	April 24, 2023	May 5, 2023	0.525
June 30, 2023	July 24, 2023	August 4, 2023	0.525
September 30, 2023	October 23, 2023	November 3, 2023	0.525

USAC's Warrants

As of September 30, 2023 and December 31, 2022, USAC warrants with the right to purchase 10,000,000 USAC common units at a strike price of $19.59 per unit were outstanding. On October 27, 2023, such warrants were exercised in full by the holders. The exercise of the warrants will be net settled for approximately 2,360,000 USAC common units.

Accumulated Other Comprehensive Income

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

	September 30, 2023	December 31, 2022
Unrealized gains on available-for-sale securities	$ 11	$ 9
Foreign currency translation adjustment	6	1
Actuarial loss related to pensions and other postretirement benefits	(7)	(7)
Investments in unconsolidated affiliates, net	19	13
Total AOCI included in partners' capital, net of tax	$ 29	$ 16

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

FERC Proceedings

Rover – FERC - Stoneman House

In late 2016, FERC Enforcement Staff began a non-public investigation related to Rover's purchase and removal of a potentially historic home (known as the Stoneman House) while Rover's application for permission to construct the new 711-mile interstate natural gas pipeline and related facilities was pending. On March 18, 2021, FERC issued an Order to Show Cause and Notice of Proposed Penalty (Docket No. IN19-4-000), ordering Rover to explain why it should not pay a $20 million civil penalty for alleged violations of FERC regulations requiring certificate holders to be forthright in their submissions of information to the FERC. Rover filed its answer and denial to the order on June 21, 2021 and a surreply on September 15, 2021. FERC issued an order on January 20, 2022 setting the matter for hearing before an administrative law judge. The hearing was set to commence on March 6, 2023; as explained below, this FERC proceeding has been stayed.

On February 1, 2022, Energy Transfer and Rover filed a Complaint for Declaratory Relief in the United States District Court for the Northern District of Texas ("Federal District Court") seeking an order declaring that FERC must bring its enforcement action in federal district court (instead of before an administrative law judge). Also on February 1, 2022, Energy Transfer and Rover filed an expedited request to stay the proceedings before the FERC administrative law judge pending the outcome of the Federal District Court case. On May 24, 2022, the Federal District Court ordered a stay of the FERC's enforcement case and the District Court case pending the resolution of two cases pending before the United States Supreme Court. Arguments were heard in those cases on November 7, 2022. On April 14, 2023, the United States Supreme Court held against the government in both cases, finding that the federal district courts had jurisdiction to hear those suits and to resolve the parties' constitutional challenges. The cases were remanded to the federal district courts for further proceedings.

On September 13, 2023 the District Court ordered that the District Court case would be stayed pending the resolution of another case pending before the United States Supreme Court and that the FERC enforcement case would remain stayed. Energy Transfer and Rover intend to vigorously defend this claim.

Rover – FERC - Tuscarawas

In mid-2017, FERC Enforcement Staff began a non-public investigation regarding allegations that diesel fuel may have been included in the drilling mud at the Tuscarawas River horizontal directional drilling ("HDD") operations. Rover and the Partnership are cooperating with the investigation. In 2019, Enforcement Staff provided Rover with a notice pursuant to Section 1b.19 of the FERC regulations that Enforcement Staff intended to recommend that the FERC pursue an enforcement action against Rover and the Partnership. On December 16, 2021, FERC issued an Order to Show Cause and Notice of Proposed Penalty (Docket No. IN17-4-000), ordering Rover and Energy Transfer to show cause why they should not be found to have violated Section 7(e) of the Natural Gas Act, Section 157.20 of FERC's regulations, and the Rover Pipeline Certificate Order, and assessed civil penalties of $40 million.

Rover and Energy Transfer filed their answer to this order on March 21, 2022, and Enforcement Staff filed a reply on April 20, 2022. Rover and Energy Transfer filed their surreply to this order on May 13, 2022. The primary contractor (and one of the subcontractors) responsible for the HDD operations of the Tuscarawas River site have agreed to indemnify Rover and the Partnership for any and all losses, including any fines and penalties from government agencies, resulting from their actions in conducting such HDD operations. Given the stage of the proceedings, the Partnership is unable at this time to provide an assessment of the potential outcome or range of potential liability, if any; however, the Partnership believes the indemnity described above will be applicable to the penalty proposed by Enforcement Staff and intends to vigorously defend itself against the subject claims.

Other FERC Proceedings

By an order issued January 16, 2019, the FERC initiated a review of Panhandle's then existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates 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 Natural Gas Act. The Natural Gas Act Section 5 and Section 4 proceedings were consolidated by order of the Chief Judge on October 1, 2019. The initial decision by the administrative law judge was issued on March 26, 2021, and on December 16, 2022, the FERC issued its order on the initial decision. On January 17, 2023, Panhandle and the Michigan Public Service Commission each filed a request for rehearing of FERC's order on the initial decision, which were denied by operation of law as of February 17, 2023. On March 23, 2023, Panhandle appealed these orders to the United States Court of Appeals for the District of Columbia Circuit ("Court of Appeals"), and the Michigan Public Service Commission also subsequently appealed these orders. On April 25, 2023, the Court of Appeals consolidated Panhandle's and Michigan Public Service Commission's appeals and stayed the consolidated appeal proceeding while FERC further considered the requests for rehearing of its December 16, 2022 order. On September 25, 2023, FERC issued its order addressing arguments raised on rehearing and compliance, which denied our requests for rehearing. Panhandle is evaluating the September 25 order and has sixty days from that date to appeal the order to the Court of Appeals.

On December 1, 2022, Sea Robin filed a rate case pursuant to Section 4 of the Natural Gas Act. By order dated June 29, 2023, a revised procedural schedule was adopted in this proceeding setting the commencement of the hearing for January 9, 2024, with an initial decision anticipated by May 21, 2024. Subsequently, by Order of the Acting Chief Administrative Law Judge, deadlines in the procedural schedule were extended, including revised hearing commencement and initial decisions deadlines to March 26, 2024 and August 8, 2024, respectively.

In May 2021, the FERC commenced an audit of 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 reporting requirements. An audit report was received in September 2023 noting no issues that would have a material impact on the Partnership's financial position or results of operations.

Internal Revenue Service Audits

The Partnership's 2020 U.S. Federal income tax return is currently under examination by the Internal Revenue Service ("IRS"). In general, Energy Transfer and its subsidiaries are no longer subject to examination by the IRS and most state jurisdictions for 2017 and prior tax years.

USAC is currently under examination by the IRS for years 2019 and 2020. The IRS has issued preliminary partnership examination changes, along with imputed underpayment computations. Based on discussions with the IRS, USAC has estimated a potential range of loss up to $25 million. Once a final partnership imputed underpayment, if any, is determined, USAC's general partner may either elect to pay the imputed underpayment (including any applicable penalties and interest) directly to the IRS or, if eligible, issue a revised information statement to each USAC unitholder, and former USAC unitholder, with respect to an audited and adjusted return.

Commitments

In the normal course of business, Energy Transfer purchases, processes and sells natural gas pursuant to long-term contracts and enters into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. Energy Transfer believes 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 following table reflects ROW expense included in operating expenses in the accompanying consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
ROW expense	$ 20	$ 16	$ 46	$ 44

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. Due to the flammable and combustible nature of natural gas and crude oil, the potential exists for personal injury and/or property damage to occur 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 parties to various legal proceedings, arbitrations 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, 2023 and December 31, 2022, accruals of approximately $947 million and $200 million, respectively, were reflected on our consolidated balance sheets related to contingent obligations 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 $200 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.

The following sections include descriptions of certain matters that could impact the Partnership's financial position, results of operations and/or cash flows in future periods. The following sections also include updates to certain matters that have previously been disclosed, even if those matters are not anticipated to have a potentially significant impact on future periods. In addition to the matters disclosed in the following sections, the Partnership is also involved in multiple other matters that could impact future periods, including other lawsuits and arbitration related to the Partnership's commercial agreements. With respect to such matters, contingencies that met both the probable and reasonably estimable criteria have been included in the accruals disclosed above, and the range of additional losses disclosed above also reflects any relevant amounts for such matters.

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 the Dakota Access Pipeline to be shut down and emptied of oil by August 5, 2020. Dakota Access and the USACE appealed to the 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 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. On September 20, 2021, Dakota Access filed a petition with the U.S. Supreme Court to hear the case. Oppositions were filed by the Solicitor General (December 17, 2021) and the Tribes (December 16, 2021). Dakota Access filed their reply on January 4, 2022. On February 22, 2022, the U.S. Supreme Court declined 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. 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. On May 21, 2021, the District Court denied the plaintiffs' request for an injunction. On June 22, 2021, the District Court terminated the consolidated lawsuits and dismissed all remaining outstanding counts without prejudice.

On September 8, 2023, the USACE published the Draft EIS. The USACE anticipates that a Final EIS and Record of Decision would be issued in 2024. The pipeline continues to operate pending completion of the EIS. Energy Transfer cannot determine when or how future lawsuits will be resolved or the impact they may have on the Bakken Pipeline, which consists of both Dakota Access and the Energy Transfer Crude Oil Pipeline; however, Energy Transfer expects that 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 Mont Belvieu LP's ("Lone Star"), now known as Energy Transfer Mont Belvieu NGLs LP, 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 and Energy Transfer R&M (collectively, "Sunoco Defendants") are defendants in lawsuits alleging methyl tertiary butyl ether ("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, 2023, Sunoco Defendants are defendants in two cases: one case initiated by the State of Maryland and one by the Commonwealth of Pennsylvania. The actions brought also named as defendants ETO, ETP Holdco Corporation and Sunoco Partners Marketing & Terminals L.P., now known as Energy Transfer Marketing & Terminals L.P. ETP Holdco Corporation and Energy Transfer Marketing & Terminals L.P. are wholly-owned subsidiaries of Energy Transfer.

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.

Litigation Filed By or Against Williams

In April and May 2016, The Williams Companies, Inc. ("Williams") filed two lawsuits (the "Williams Litigation") against Energy Transfer, LE GP, LLC, and, in one of the lawsuits, Energy Transfer Corp LP, ETE Corp GP, LLC, and Energy Transfer Equity GP, LLC (collectively, "Energy Transfer Defendants") in the Delaware Court of Chancery ("the Court"), alleging that the Energy Transfer Defendants breached their obligations under the Energy Transfer-Williams merger agreement (the "Merger Agreement"). In general, Williams alleges that the Energy Transfer 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. Williams asked the Court to compel the Energy Transfer Defendants to close the merger or take various other affirmative actions.

After a two-day trial on June 20 and 21, 2016, the Court ruled in favor of the Energy Transfer Defendants and issued a declaratory judgment that Energy Transfer 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 or certain of the alleged untrue representations and warranties. On March 23, 2017, the Delaware Supreme Court affirmed this 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 (the "Termination Fee") based on the alleged breaches of the Merger Agreement listed above. The Energy Transfer Defendants filed amended counterclaims and affirmative defenses, asserting that Williams materially breached the Merger Agreement by, among other things, (a) modifying and qualifying its board recommendation in a manner adverse to the merger, (b) failing to use its reasonable best efforts to consummate the merger, (c) failing to provide material information to Energy Transfer for inclusion in the Form S-4 related to the merger, (d) failing to facilitate the financing of the merger and (e) breaching the Merger Agreement's forum-selection clause. The Energy Transfer Defendants sought a $1.48 billion termination fee under the Merger Agreement and additional damages caused by Williams' misconduct.

On September 29, 2016, Williams filed a motion to dismiss the Energy Transfer Defendants' amended counterclaims and to strike certain of the Energy Transfer Defendants' affirmative defenses. On December 1, 2017, the Court issued a Memorandum Opinion granting in part and denying in part Williams' motion to dismiss. The Court dismissed, among other things, the Energy Transfer Defendants' claim for a $1.48 billion termination fee.

Trial was held on all remaining claims on May 10-17, 2021, and on December 29, 2021, the Court ruled in favor of Williams and awarded it the Termination Fee plus certain fees and expenses, holding that the Issuance breached the Merger Agreement and that Williams had not materially breached the Merger Agreement, though the Court awarded sanctions against Williams due to its CEO's intentional spoliation of evidence. The Court subsequently awarded Williams approximately $190 million in attorneys' fees, expenses and pre-judgment interest.

On September 21, 2022, the Court entered a final judgment against the Energy Transfer Defendants in the amount of approximately $601 million plus post-judgment interest at a rate of 3.5% per year, compounded quarterly. The Energy Transfer Defendants filed a notice of appeal on October 21, 2022 and filed their opening brief in support of their appeal on December 30, 2022. Williams filed their answering brief on January 20, 2023, and the Energy Transfer Defendants filed their reply brief on February 6, 2023. The Delaware Supreme Court heard oral argument on July 12, 2023.

On October 10, 2023, the Delaware Supreme Court affirmed. On October 25, 2023, Energy Transfer Defendants filed a motion for reargument. Therefore, the mandate will not issue until the Delaware Supreme Court disposes of that motion.

Once the mandate issues, the previously-stayed judgment in the amount of approximately $617 million will become effective, plus additional post-judgment interest.

Rover - State of Ohio

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and other defendants (collectively, the "Defendants") seeking to recover approximately $2.6 million in 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. On April 22, 2020, the Ohio Supreme Court granted the review. On March 17, 2022, the Ohio Supreme Court reversed in part and remanded to the Ohio trial court. The Ohio Supreme Court agreed with Rover that the State of Ohio had waived its rights under Section 401 of the Clean Water Act but remanded to the trial court to determine whether any of the allegations fell outside the scope of the waiver.

On remand, the Ohio EPA voluntarily dismissed four of the other five defendants and dismissed one of its counts against Rover. In its Fourth Amended Complaint, the Ohio EPA removed all paragraphs that alleged violations by the four dismissed defendants, including those where the dismissed defendants were alleged to have acted jointly with Rover or others. At a June 2, 2022, status conference, the trial judge set a schedule for Rover and the other remaining defendant to file motions to dismiss the Fourth Amended Complaint. On August 1, 2022, Rover and the other remaining defendant each filed their respective motions. Briefing on those motions was completed on November 4, 2022. By order issued on October 20, 2023, the trial judge dismissed the Ohio EPA's Fourth Amended Complaint.

Unitholder Litigation Regarding Pipeline Construction

Various purported unitholders of Energy Transfer have filed derivative actions against various past and current members of Energy Transfer's Board of Directors, LE GP, LLC, and Energy Transfer, as a nominal defendant that assert claims for breach of fiduciary duties, unjust enrichment, waste of corporate assets, breach of Energy Transfer's Partnership Agreement, tortious interference, abuse of control and gross mismanagement related primarily to matters involving the construction of pipelines in Pennsylvania and Ohio. They also seek damages and changes to Energy Transfer'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.); Barry King v. LE GP, Case No. 3:20-cv-00719-X (N.D. Tex.); Inter-Marketing Group USA, Inc. v. LE GP, et at., Case No. 2022-0139-SG (Del. Ch.); Elliot v. LE GP LLC, Case No. 3:22-cv-01527-B (N.D. Tex.); Chapa v. Kelcy L. Warren, et al., Index No. 611307/2022 (N.Y. Sup. Ct.); Elliott v. LE GP et al, Cause No. DC-22-14194 (Dallas County, Tex.); and Charles King v. LE GP, LLC et al, Cause No. DC-22-14159 (Dallas County, Texas). The Barry King action that was filed in the United States District Court for the Northern District of Texas (Case No. 3:20-cv-00719-X) has been consolidated with the Bettiol action. On August 9, 2022, the Elliot action that was filed in the United States District Court for the Northern District of Texas (Case No. 3:22-cv-01527-B) was voluntarily dismissed.

Another purported unitholder of Energy Transfer, 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 Energy Transfer and three of Energy Transfer'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 Energy Transfer directors Marshall McCrea and Matthew S. 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. Discovery is ongoing. On August 23, 2022, the court granted in part and denied in part ACERS' motion for class certification. The court certified a class consisting of those who purchased or otherwise acquired common units of Energy Transfer between February 25, 2017 and November 11, 2019.

On June 3, 2022, another purported unitholder of Energy Transfer, Mike Vega, filed suit, purportedly on behalf of a class, against Energy Transfer and Messrs. Warren, Long, McCrea and Whitehurst. See Vega v. Energy Transfer LP et al., Case No. 1:22-cv-4614 (S.D.N.Y.). The action asserts claims for violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder related primarily to statements made in connection with the construction of Rover. On August 10, 2022, the court appointed the New Mexico State Investment Council and Public Employees Retirement Association of New Mexico (the "New Mexico Funds") as lead plaintiffs. New Mexico Funds filed an amended complaint on September 30, 2022 and added as additional defendants Energy Transfer directors John W. McReynolds and Matthew S. Ramsey. On November 7, 2022, the court granted the defendants' motion to transfer and transferred this action to the United States District Court for the Northern District of Texas. On January 27, 2023, the defendants filed their motion to dismiss the New Mexico Funds' amended complaint.

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, Inc. (R&M), LLC (now known as Energy Transfer R&M) and Energy Transfer Marketing & Terminals L.P. (collectively, "ETMT") that alleged ETMT 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 District 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, ETMT filed its Notice of Appeal with the 10th Circuit Court of Appeals ("10th Circuit") and appealed the entirety of the Order. The matter was fully briefed, and oral argument was set for November 15, 2021. However, on November 1, 2021, the 10th Circuit dismissed the appeal due to jurisdictional concerns with finality of the Order. En banc rehearing of this decision was denied on November 29, 2021. On December 1, 2021, ETMT filed a Petition for Writ of Mandamus to the 10th Circuit to correct the jurisdictional problems and secure final judgment. On February 2, 2022, the 10th Circuit denied the Petition for Writ of Mandamus, citing that there are other avenues for ETMT to obtain adequate relief. On February 10, 2022, ETMT filed a Motion to Modify the Plan of Allocation Order and Issue a Rule 58 Judgment with the trial court, requesting the District Court to enter a final judgment in compliance with the Rules. ETMT also filed an injunction with the trial court to enjoin all efforts by plaintiffs to execute on any non-final judgment. On March 31, 2022, Judge Gibney denied the Motion to Modify the Plan of Allocation, reiterating his thoughts that the order constitutes a final judgment. Judge Gibney granted the injunction in part (placing a hold on enforcement efforts for 60 days) and denied the injunction in part. The injunction has since been lifted.

Despite the fact that ETMT has taken the position that the judgment is not final and not subject to execution, the Class engaged in asset discovery and actively tried to collect on the judgment through garnishment proceedings from ETMT's customers. ETMT unsuccessfully tried to deposit the funds into the District Court's Registry. Accordingly, to stop the garnishment proceedings, on December 2, 2022, ETMT wired approximately $161 million to the Plaintiff's approved Plan Administrator, which represents the full amount of the judgment with attorney's fees and post-judgment interest. ETMT did so without waiving its ability to pursue its pending appeal or its right to appeal the merits of the judgment. Plaintiff has since dismissed the garnishment actions.

ETMT cannot predict the outcome of the case, nor can ETMT predict the amount of time and expense that will be required to resolve the appeal. ETMT has been vigorous and diligent in its appeals relating to the finality issues underlying the Order and appealed the denial of the Motion to Modify to the 10th Circuit in an attempt to get a decision on finality. The appeal was fully briefed, and oral argument was held on March 21, 2023. On August 3, 2023, the 10th Circuit ruled in favor of ETMT and found that the district court's plan of allocation (which was part of the final judgment) did not satisfy all finality requirements. The Court held that the district court abused its discretion in denying ETMT's Rule 60(b)(6) Motion to Modify and reversed and remanded for further proceedings. The case is now back at the trial court so that the district court can fix the finality requirements with the judgment. Further, ETMT sought and recovered a return of funds deposited with the Plan Administrator; Class Counsel did not oppose this motion.

At a status hearing on September 28, 2023, Class Counsel indicated that it would seek additional interest up until the date that the final judgment is entered. The District Court asked for briefing on the issue of additional interest and held a hearing on October 17, 2023 to address this issue further and enter a ruling as to whether additional interest should be added to the judgment total. During the hearing, the District Court ruled that additional interest should be awarded at the 12% statutory rate from the date of the prior improper judgment up until October 17, 2023. However, the Judge tolled the running of interest for the time period during which the Plan Administrator was in possession of Sunoco's funds (between November 2, 2022 and October 10, 2023). Based on this ruling, the Class calculated that approximately $23 million in additional interest should be added to the final judgment. On October 19, 2023, the District Court entered the new final judgment with a corrected Plan of Allocation. Both Parties agree that this newly entered judgment fixes the finality concerns and will allow an appeal to the 10th Circuit on the merits. With the inclusion of additional interest, the total amount awarded to the Plaintiffs is approximately $104 million in actual damages and $75 million in punitive damages. Sunoco intends on appealing the entirety of the judgment.

Energy Transfer LP and ETC Texas Pipeline, Ltd. v. Culberson Midstream LLC, et al.

On April 8, 2022, Energy Transfer and ETC Texas Pipeline, Ltd. ("ETC," and together with Energy Transfer, "Plaintiffs") filed suit against Culberson Midstream LLC ("Culberson"), Culberson Midstream Equity, LLC ("Culberson Equity"), and Moontower Resources Gathering, LLC ("Moontower"). On October 1, 2018, ETC and Culberson entered into a Gas Gathering and Processing Agreement (the "Bypass GGPA") under which Culberson was to gather gas from its dedicated acreage and deliver all committed gas exclusively to ETC. In connection with the Bypass GGPA, on October 18, 2018, Energy Transfer and Culberson Equity also entered into an Option Agreement. Under the Option Agreement, Culberson Equity and Moontower had the right (but not the obligation) to require Energy Transfer to purchase their respective interests in Culberson by way of a put option. Notably, the Option Agreement is only enforceable so long as the parties comply with the Bypass GGPA. In late March 2022, Culberson Equity and Moontower submitted a put notice to Energy Transfer seeking to require Energy Transfer to purchase their respective interests in Culberson for approximately $93 million. On April 8, 2022, Plaintiffs filed suit against Culberson, Culberson Equity and Moontower asserting claims for declaratory judgment and breach of contract, contending that they materially breached the Bypass GGPA by sending some committed gas to third parties and also by failing to send any gas to Plaintiffs since March 2020, and thus that Culberson Equity's and Moontower's put notice is void. Culberson, Culberson Equity, and Moontower have answered the lawsuit. Additionally, Culberson filed a counterclaim against ETC for breach of the Bypass GGPA, seeking the recovery of damages and attorneys' fees. Culberson Equity and Moontower also filed a counterclaim against Energy Transfer for (1) breach of the Option Agreement, and (2) a declaratory judgment concerning Energy Transfer's alleged obligation to purchase the Culberson interests. The lawsuit is pending in the 193rd Judicial District Court ("the Court") in Dallas County, Texas. On April 27, 2022, Culberson filed an application for a temporary restraining order, temporary injunction, and permanent injunction, and Culberson Equity and Moontower joined in that request. The Court held a hearing on the application on April 28 and denied the injunction. In early May, Culberson filed a motion to enforce the appraisal process and confirm the validity of their put price calculation, to which Plaintiffs objected. On July 11, 2022, the Court held a hearing on the motion, and on July 19, 2022, the Court ordered the parties to engage in an appraisal process regarding the put price. An independent appraiser was appointed and issued his decision on October 15, 2022, concluding that the put price totals $93 million. Plaintiffs have consistently reiterated their objection to the appraisal process and conclusion.

On October 6, 2022, Culberson, Culberson Equity and Moontower filed a motion for summary judgment, but the Court postponed considering it until after further document discovery and depositions. On December 7, 2022, Plaintiffs amended their petition to add Moontower Resources Operating, LLC and Moontower Resources WI, LLC as Defendants, and to assert a claim against all Defendants for fraudulent inducement.

Defendants refiled updated motions for summary judgment on May 5, 2023, seeking summary judgment on: (1) Plaintiffs' breach of contract and declaratory judgment claims on a no-evidence basis; (2) Plaintiffs' fraud and alter ego claims on a no-evidence basis; and (3) Plaintiffs' fraud claim on a traditional basis. Plaintiffs responded on June 6, 2023. Defendants submitted their replies in support of summary judgment on June 12, 2023.

On June 5, 2023, counsel for Defendants informed the Court via a letter that Defendants were continuing the submission date of the no-evidence motion regarding Plaintiffs' breach of contract and declaratory judgment claims, noting that such submission would be rescheduled along with a traditional summary judgment motion regarding the same subject matter. To that end, on July 17, 2023, Defendant Culberson Midstream, LLC filed a Traditional Motion for Summary Judgment on Plaintiffs' Breach of Contract and Declaratory Judgment Claims, while Defendants Culberson Midstream Equity, LLC and Moontower Resources Gathering filed a Motion for Partial Summary Judgment Regarding the Breach of the Option Agreement. Further, on July 25, 2023, Defendants filed a Traditional and No-Evidence Motion for Summary Judgment Regarding Damages and Recission. On July 28, 2023, in turn, Plaintiff ETC Texas Pipeline, Ltd. filed a Traditional Motion for Partial Summary Judgment on Breach of Contract and Declaratory Judgment.

On September 20, 2023, the Court held oral argument on the various Motions for Summary Judgment. Following oral argument, on September 26, 2023, the Court ruled on each of the Motions. The Court denied Defendants' Traditional Motion for Partial Summary Judgment Regarding Fraud, Defendants' No Evidence Motion for Summary Judgment Regarding Plaintiffs' Fraud and Alter Ego Claims, Defendants' Traditional and No Evidence Motion for Partial Summary Judgment Regarding Damages and Rescission, and Plaintiff ETC Texas Pipeline, Ltd.'s Traditional Motion for Partial Summary Judgment on Breach of Contract and Declaratory Judgment. The Court granted Culberson Midstream, LLC's Traditional Motion for Partial Summary Judgment Seeking Dismissal of Plaintiffs' Breach of Contract and Declaratory Judgment Claims and Culberson Midstream Equity, LLC and Moontower Resources Gathering, LLC's Motion for Partial Summary Judgment Regarding Breach of the Option Agreement.

Discovery has closed in this matter. Trial on the remaining issues is currently set for June 18, 2024. Plaintiffs cannot predict the ultimate outcome of this litigation or the amount of time and expense that will be required to resolve it.

Massachusetts Attorney General v. New England Gas Company

On July 7, 2011, the Massachusetts Attorney General (the "MA AG") filed a regulatory complaint with the Massachusetts Department of Public Utilities ("DPU") against New England Gas Company ("NEG") with respect to certain environmental cost recoveries. NEG was an operating division of Southern Union Company ("SUG"), and the NEG assets were acquired in connection with the merger transaction with Energy Transfer in March 2012. Subsequent to the merger, in 2013, SUG sold the NEG assets to Liberty Utilities ("Liberty," and together with NEG and SUG, "Respondents") and retained certain potential liabilities, including the environmental cost recoveries with respect to the pending complaint before the DPU. Specifically, the MA AG seeks a refund to NEG's ratepayers for approximately $18 million in legal fees associated with SUG environmental response activities. The MA AG requests that the DPU initiate an investigation into NEG's collection and reconciliation of recoverable environmental costs, namely: (1) the legal fees charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005; (2) the legal fees charged by the Bishop, London & Dodds firm and passed through the recovery mechanisms since 2005; and (3) the legal fees passed through the recovery mechanism that the MA AG contends only qualify for a lesser (i.e., 50 percent) level of recovery. Respondents maintain that, by tariff, these costs are recoverable through rates charged to NEG customers pursuant to the environmental remediation adjustment clause program. After the Respondents answered the complaint and filed a motion to dismiss in 2011, the Hearing Officer deferred decision on the motion to dismiss and issued a stay of discovery pending resolution of a discovery dispute, which it later lifted on June 24, 2013, permitting the case to resume. However, the MA AG failed to take any further steps to prosecute its claims for nearly seven years. The case remained largely dormant until February 2022, when the Hearing Officer denied the motion to dismiss. After receiving input from the parties, the Hearing Officer entered a procedural schedule on March 16, 2022 (which was amended slightly on August 22, 2022). The parties engaged in discovery and the preparation of pre-filed testimony. Respondents submitted their pre-filed testimony on July 11, 2022. The MA AG served three sets of discovery requests on Respondents on September 9, September 12, and September 20, respectively, to which Respondents timely responded. On October 5, 2022, the MA AG requested that the DPU issue a ruling on whether the information that Respondents redacted in their attorneys' fees invoices is protected by the attorney-client privilege. On the same day, the MA AG also filed a Motion to Stay the Procedural Schedule pending a ruling on the privilege issue. On October 6, 2022, without even affording Respondents the opportunity to respond, the DPU granted the MA AG's request to stay the procedural schedule. Accordingly, all previous deadlines (including the MA AG's October 7, 2022, deadline to submit direct pre-filed testimony) are presently stayed. On October 18, 2023, the DPU issued an Order on Attorney General's Motion to Compel, ruling on issues originally raised in a motion to compel that the MA AG filed in 2013. The October 18, 2023 Order directs NEG to review its redactions again and, to the extent any invoices are completely redacted or heavily redacted, to provide more lightly redacted versions within 30 days. The October 18, 2023 Order also states that the MDPU will set a new procedural schedule in this matter sometime after NEG complies with the directives in the order. Respondents cannot predict the ultimate outcome of this regulatory proceeding, nor can they predict the amount of time and expense that will be required to resolve these claims; however, Respondents will vigorously defend themselves against the MA AG's claims.

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. that 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, 2023, the Partnership had been named as a PRP at approximately 31 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 following table reflects the amounts of accrued liabilities recorded in our consolidated balance sheets related to environmental matters that are considered to be probable and reasonably estimable. Currently, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. Except for matters discussed above, we do not have any material environmental matters assessed as reasonably possible that would require disclosure in our consolidated financial statements.

	September 30, 2023	December 31, 2022
Current	$ 44	$ 54
Non-current	240	228
Total environmental liabilities	$ 284	$ 282

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, 2023 and 2022, the Partnership recorded $23 million and $8 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 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 the Federal Occupational Safety and Health Act ("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; however, 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, 2022	$ 615
Additions	794
Revenue recognized	(836)
Balance, September 30, 2023	$ 573
Balance, December 31, 2021	$ 459
Additions	815
Revenue recognized	(688)
Other	(13)
Balance, September 30, 2022	$ 573

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

	September 30, 2023	December 31, 2022
Contract assets	$ 239	$ 200
Accounts receivable from contracts with customers	1,079	834

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 components of the contracts are included in the following table.

As of September 30, 2023, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations was $39.83 billion. The Partnership expects to recognize this amount as revenue within the time bands illustrated in the following table:

	Years Ending December 31,				
	2023 (remainder)	2024	2025	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of September 30, 2023	$ 2,176	$ 7,345	$ 6,247	$ 24,062	$ 39,830

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 natural gas, 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 intrastate 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 intrastate 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, 2023		December 31, 2022	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	330	2023-2024	145	2023
Basis Swaps IFERC/NYMEX [(1)]	(44,800)	2023-2024	(39,563)	2023
Power (Megawatt):				
Forwards	171,600	2023-2029	—	2023-2029
Futures	(74,391)	2023-2024	(21,384)	2023
Options – Puts	68,800	2023-2024	119,200	2023
Options – Calls	—	2023-2024	—	—
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	48,393	2023-2025	42,440	2023-2024
Swing Swaps IFERC	(72,220)	2023-2025	(202,815)	2023-2024
Fixed Swaps/Futures	(4,803)	2023-2025	(15,758)	2023-2025
Forward Physical Contracts	(2,145)	2023-2025	2,423	2023-2024
NGLs (MBbls) – Forwards/Swaps	(14,238)	2023-2026	6,934	2023-2025
Crude (MBbls) – Forwards/Swaps	(7,660)	2023-2025	795	2023-2024
Refined Products (MBbls) – Futures	(5,751)	2023-2025	(3,547)	2023-2024
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(43,745)	2023-2024	(37,448)	2023
Fixed Swaps/Futures	(43,745)	2023-2024	(37,448)	2023
Hedged Item – Inventory	43,745	2023-2024	37,448	2023

(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 (including USAC's), none of which were designated as hedges for accounting purposes:

		Notional Amount Outstanding	
Term	Type[(1)]	September 30, 2023	December 31, 2022
Energy Transfer:			
July 2024[(2)]	Forward-starting to pay an average fixed rate of 3.388% and receive a floating rate	$ —	$ 400
USAC:			
April 2025[(3)]	Pay a fixed rate of 3.785% and receive a floating rate (effective April 2023)	700	—

(1) Floating rates are based on SOFR.

(2) The July 2024 interest rate swaps were terminated and settled in August 2023.

(3) In October 2023, USAC modified its April 2025 interest rate swap. The termination date was extended from April 1, 2025 to December 31, 2025. Under the modified interest rate swap, USAC pays a fixed interest rate of 3.9725% and continues to receive floating interest rate payments that are indexed to the one-month SOFR.

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.

Our natural gas transportation and midstream revenues are derived significantly from companies that engage in exploration and production activities. In addition to oil and gas producers, the Partnership's counterparties consist of a diverse portfolio of customers across the energy industry, including petrochemical companies, commercial and industrial end-users, 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 on 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 net income or other comprehensive income.

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	September 30, 2023	December 31, 2022	September 30, 2023	December 31, 2022
Derivatives designated as hedging instruments:				
Commodity derivatives – margin deposits	$ 23	$ 87	$ (7)	$ (7)
	23	87	(7)	(7)
Derivatives not designated as hedging instruments:				
Commodity derivatives – margin deposits	311	506	(371)	(411)
Commodity derivatives	71	95	(71)	(108)
Interest rate derivatives	14	—	—	(23)
	396	601	(442)	(542)
Total derivatives	$ 419	$ 688	$ (449)	$ (549)

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, 2023	December 31, 2022	September 30, 2023	December 31, 2022
Derivatives without offsetting agreements	Derivative assets (liabilities)	$ 14	$ —	$ —	$ (23)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	71	95	(71)	(108)
Broker cleared derivative contracts	Other current assets (liabilities)	334	593	(378)	(418)
Total gross derivatives		419	688	(449)	(549)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(67)	(85)	67	85
Counterparty netting	Other current assets (liabilities)	(303)	(359)	303	359
Total net derivatives		$ 49	$ 244	$ (79)	$ (105)

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,	
		2023	2022	2023	2022
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$ 4	$ 22	$ (6)	$ 50
Commodity derivatives – Non-trading	Cost of products sold	(166)	186	(106)	(6)
Interest rate derivatives	Gains on interest rate derivatives	32	60	47	303
Total		$ (130)	$ 268	$ (65)	$ 347

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, as well as certain non-recurring gains and losses. 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,	
	2023	2022	2023	2022
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 880	$ 2,081	$ 2,424	$ 5,550
Intersegment revenues	93	302	646	668
	973	2,383	3,070	6,218
Interstate transportation and storage:				
Revenues from external customers	562	533	1,720	1,591
Intersegment revenues	9	16	35	54
	571	549	1,755	1,645
Midstream:				
Revenues from external customers	775	1,115	2,370	3,399
Intersegment revenues	2,002	3,756	5,629	10,447
	2,777	4,871	7,999	13,846
NGL and refined products transportation and services:				
Revenues from external customers	4,369	5,169	13,210	16,644
Intersegment revenues	891	906	2,654	3,265
	5,260	6,075	15,864	19,909
Crude oil transportation and services:				
Revenues from external customers	7,289	6,415	19,321	19,640
Intersegment revenues	—	1	1	2
	7,289	6,416	19,322	19,642
Investment in Sunoco LP:				
Revenues from external customers	6,317	6,577	17,395	19,767
Intersegment revenues	3	17	32	44
	6,320	6,594	17,427	19,811
Investment in USAC:				
Revenues from external customers	212	176	605	503
Intersegment revenues	5	3	16	11
	217	179	621	514
All other:				
Revenues from external customers	335	873	1,009	2,281
Intersegment revenues	109	211	378	480
	444	1,084	1,387	2,761
Eliminations	(3,112)	(5,212)	(9,391)	(14,971)
Total revenues	$ 20,739	$ 22,939	$ 58,054	$ 69,375

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$ 244	$ 301	$ 869	$ 963
Interstate transportation and storage	491	409	1,468	1,259
Midstream	631	868	1,851	2,578
NGL and refined products transportation and services	1,076	634	2,852	2,097
Crude oil transportation and services	706	461	1,906	1,616
Investment in Sunoco LP	257	276	728	681
Investment in USAC	130	109	373	313
All other	6	30	49	149
Adjusted EBITDA (consolidated)	$ 3,541	$ 3,088	$ 10,096	$ 9,656

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Reconciliation of net income to Adjusted EBITDA:				
Net income	$ 1,047	$ 1,322	$ 3,727	$ 4,431
Depreciation, depletion and amortization	1,107	1,030	3,227	3,104
Interest expense, net of interest capitalized	632	577	1,892	1,714
Income tax expense	77	82	256	159
Impairment losses and other	1	86	12	386
Gains on interest rate derivatives	(32)	(60)	(47)	(303)
Non-cash compensation expense	35	27	99	88
Unrealized (gains) losses on commodity risk management activities	107	(76)	182	(130)
Inventory valuation adjustments (Sunoco LP)	(141)	40	(113)	(81)
Adjusted EBITDA related to unconsolidated affiliates	182	147	514	409
Equity in earnings of unconsolidated affiliates	(103)	(68)	(286)	(186)
Non-operating litigation-related loss	625	—	625	—
Other, net	4	(19)	8	65
Adjusted EBITDA (consolidated)	$ 3,541	$ 3,088	$ 10,096	$ 9,656

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, 2022 filed with the SEC on February 17, 2023. 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, 2022 filed with the SEC on February 17, 2023, "Part II — Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2023 filed with the SEC on August 3, 2023 and in this Quarterly Report on Form 10-Q. Additional information on forward-looking statements is discussed in "Forward-Looking Statements."

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

RECENT DEVELOPMENTS

Pending Crestwood Acquisition

On August 16, 2023, the Partnership announced its entry into a definitive merger agreement to acquire Crestwood Equity Partners LP ("Crestwood"). Under the terms of the merger agreement, Crestwood's common unitholders will receive 2.07 Energy Transfer common units for each Crestwood common unit. Crestwood owns gathering and processing assets located in the Williston, Delaware and Powder River basins. On October 30, 2023, a majority of Crestwood's unitholders voted to approve the merger. The transaction is expected to close on November 3, 2023, subject to customary closing conditions.

Lotus Midstream Acquisition

On May 2, 2023, Energy Transfer acquired Lotus Midstream Operations, LLC ("Lotus Midstream") for total consideration of $1.50 billion. Lotus Midstream owns and operates Centurion Pipeline Company LLC, an integrated crude midstream platform located in the Permian Basin.

Sunoco LP's Acquisition

On May 1, 2023, Sunoco LP completed the acquisition of 16 refined product terminals located across the East Coast and Midwest from Zenith Energy for $111 million. Sunoco LP expects the acquisition to be accretive to its unitholders in the first year of ownership.

Quarterly Cash Distribution

In October 2023, Energy Transfer announced a quarterly distribution of $0.3125 per unit ($1.25 annualized) on Energy Transfer common units for the quarter ended September 30, 2023.

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 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 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, but also other pipeline costs that will continue to affect FERC's determination of just and reasonable cost-of-service rates. 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 Tiger Pipeline, Midcontinent Express Pipeline and Fayetteville Express Pipeline, 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 Florida Gas Transmission Pipeline, 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 changes to 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 an order issued January 16, 2019, the FERC initiated a review of Panhandle's then existing rates pursuant to Section 5 of the Natural Gas Act to determine whether the rates 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 Natural Gas Act. The Natural Gas Act Section 5 and Section 4 proceedings were consolidated by order of the Chief Judge on October 1, 2019. The initial decision by the administrative law judge was issued on March 26, 2021, and on December 16, 2022, the FERC issued its order on the initial decision. On January 17, 2023, Panhandle and the Michigan Public Service Commission each filed a request for rehearing of FERC's order on the initial decision, which were denied by operation of law as of February 17, 2023. On March 23, 2023, Panhandle appealed these orders to the United States Court of Appeals for the District of Columbia Circuit ("Court of Appeals"), and the Michigan Public Service Commission also subsequently appealed these orders. On April 25, 2023, the Court of Appeals consolidated Panhandle's and Michigan Public Service Commission's appeals and stayed the consolidated appeal proceeding while FERC further considered the requests for rehearing of its December 16, 2022 order. On September 25, 2023, FERC issued its order addressing arguments raised on rehearing and compliance, which denied our requests for rehearing. Panhandle is evaluating the September 25 order and has sixty days from that date to appeal the order to the Court of Appeals.

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. On February 18, 2021, the FERC issued another NOI ("2021 NOI"), reopening its review of the 1999 Policy Statement. Comments on the 2021 NOI were due on May 26, 2021; we filed comments in the FERC proceeding. In September 2021, FERC issued a Notice of Technical Conference on Greenhouse Gas Mitigation related to natural gas infrastructure projects authorized under Sections 3 and 7 of the Natural Gas Act. A technical conference was held on November 19, 2021, and post-technical conference comments were submitted to the FERC on January 7, 2022.

On February 18, 2022, the FERC issued two new policy statements: (1) an Updated Policy Statement on the Certification of New Interstate Natural Gas Facilities and (2) a Policy Statement on the Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews ("2022 Policy Statements"), to be effective that same day. On March 24, 2022, the FERC issued an order designating the 2022 Policy Statements as draft policy statements, and requested further comments. The FERC will not apply the now draft 2022 Policy Statements to pending applications or applications to be filed at FERC until it issues any final guidance on these topics. Comments on the 2022 Policy Statements were due on April 25, 2022, and reply comments were due on May 25, 2022. We are unable to predict what, if any, changes may be proposed as a result of the 2022 Policy Statements that might affect our natural gas pipeline or LNG facility projects, or when such new policies, if any, might become effective. We do not expect that any change in these policy statements would affect us in a materially different manner than any other natural gas pipeline company operating in the United States.

Interstate Common Carrier Regulation

Liquids pipelines transporting in interstate commerce are regulated by FERC as common carriers under the Interstate Commerce Act ("ICA"). Under the ICA, 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.

On December 17, 2020, FERC issued an order establishing a new index of PPI-FG plus 0.78%. The FERC received requests for rehearing of its December 17, 2020 order and on January 20, 2022, granted rehearing and modified the oil index. Specifically, for the five-year period commencing July 1, 2021 and ending June 30, 2026, FERC-regulated liquids pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI-FG minus 0.21%. FERC directed liquids pipelines to recompute their ceiling levels for July 1, 2021 through June 30, 2022, as well as the ceiling levels for the period July 1, 2022 to June 30, 2023, based on the new index level. Where an oil pipeline's filed rates exceed its ceiling levels, FERC ordered such oil pipelines to reduce the rate to bring it into compliance with the recomputed ceiling level to be effective March 1, 2022. Some parties sought rehearing of the January 20 order with FERC, which was denied by FERC on May 6, 2022. Certain parties have appealed the January 20 and May 6 orders. Such appeals remain pending at the D.C. Circuit.

On October 20, 2022, the FERC issued a policy statement on the Standard Applied to Complaints Against Oil Pipeline Index Rate Changes to establish guidelines regarding how the FERC will evaluate shipper complaints against oil pipeline index rate increases. Specifically, the policy statement adopted the proposal in the FERC's earlier Notice of Inquiry issued on March 25, 2020 to eliminate the "Substantially Exacerbate Test" as the preliminary screen applied to complaints against index rate increases and instead adopt the proposal to apply the "Percentage Comparison Test" as the preliminary screen for both protests and complaints against index rate increases. At this time, we cannot determine the effect of a change in the FERC's preliminary screen for complaints against index rates changes, however, a revised screen would result in a threshold aligned with the existing threshold for protests against index rate increases. Any complaint or protest raised by a shipper could materially and adversely affect our financial condition, results of operations or cash flows.

Air Quality Standards

The EPA recently finalized its Good Neighbor Plan (the "Plan") which seeks to reduce nitrogen oxide pollution from power plants and other industrial facilities from 23 upwind states which the EPA determined is contributing to National Ambient Air Quality Standards (NAAQS) nonattainment and interfering with maintenance of the 2015 ozone NAAQS in downwind states. As part of the Plan, the EPA announced that it would be issuing prescriptive emission standards for several sectors, including certain new and existing internal combustion engines of a certain size used in pipeline transportation of natural gas. The EPA's final rule was to become effective on August 4, 2023, and the prescribed emission standards were scheduled to be effective in 2026; however, of the nine states impacted within the Partnership's footprint, effectiveness of the rule is currently stayed in six states and pending a decision on a stay in three other states. Additionally, other operators and industry groups have challenged the Plan in the D.C. Circuit. Although the stay was denied, it was promptly followed by the filing of an emergency stay application with the U.S. Supreme Court, which is still pending. The Partnership currently estimates that the final rule would require retrofitting or replacement of approximately 240 engines in its interstate and intrastate natural gas transportation and storage operations. The Partnership is involved in challenging application of the Plan in the nine states impacted within its footprint. Compliance with the Plan (if implementation is not stayed or otherwise delayed) will still require substantial capital expenditures which could adversely affect our business in future periods. However, at this time, we are still assessing the potential costs of this rule and, given uncertainties resulting from the multiple legal challenges filed against the Plan in various states, in the DC Circuit and the U.S. Supreme Court, we cannot predict with any certainty what the final costs of compliance for the Plan for the Partnership ultimately may be. For additional information on how our operations could be impacted by regulatory developments related to the 2015 ozone NAAQS, please see "Item 1. Business – Regulation – Environmental Matters – Air Emissions" and the risk factor entitled "Our business involves the generation, handling and disposal of hazardous substances, hydrocarbons and wastes which activities are subject to environmental and worker health and safety laws and regulations that may cause us to incur significant costs and liabilities" in "Item 1A. Risk Factors – Risks Relating to the Partnership's Business – Regulatory Matters" included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2022 filed with the SEC on February 17, 2023.

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, as well as certain non-recurring gains and losses. 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 following table, 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,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$ 244	$ 301	$ (57)	$ 869	$ 963	$ (94)
Interstate transportation and storage	491	409	82	1,468	1,259	209
Midstream	631	868	(237)	1,851	2,578	(727)
NGL and refined products transportation and services	1,076	634	442	2,852	2,097	755
Crude oil transportation and services	706	461	245	1,906	1,616	290
Investment in Sunoco LP	257	276	(19)	728	681	47
Investment in USAC	130	109	21	373	313	60
All other	6	30	(24)	49	149	(100)
Adjusted EBITDA (consolidated)	$ 3,541	$ 3,088	$ 453	$ 10,096	$ 9,656	$ 440

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Change	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	Change
Reconciliation of net income to Adjusted EBITDA:						
Net income	$ 1,047	$ 1,322	$ (275)	$ 3,727	$ 4,431	$ (704)
Depreciation, depletion and amortization	1,107	1,030	77	3,227	3,104	123
Interest expense, net of interest capitalized	632	577	55	1,892	1,714	178
Income tax expense	77	82	(5)	256	159	97
Impairment losses and other	1	86	(85)	12	386	(374)
Gains on interest rate derivatives	(32)	(60)	28	(47)	(303)	256
Non-cash compensation expense	35	27	8	99	88	11
Unrealized (gains) losses on commodity risk management activities	107	(76)	183	182	(130)	312
Inventory valuation adjustments (Sunoco LP)	(141)	40	(181)	(113)	(81)	(32)
Adjusted EBITDA related to unconsolidated affiliates	182	147	35	514	409	105
Equity in earnings of unconsolidated affiliates	(103)	(68)	(35)	(286)	(186)	(100)
Non-operating litigation-related loss	625	—	625	625	—	625
Other, net	4	(19)	23	8	65	(57)
Adjusted EBITDA (consolidated)	$ 3,541	$ 3,088	$ 453	$ 10,096	$ 9,656	$ 440

Net Income. For the three and nine months ended September 30, 2023 compared to the same periods last year, net income decreased $275 million and $704 million, respectively, or approximately 21% and 16%, respectively. For both the three-month and nine-month periods, net income was significantly impacted by the recognition of a $625 million non-operating litigation-related loss in the third quarter of 2023, as well as decreases in gains on interest rate derivatives and increases in depreciation, depletion and amortization; each of these items is discussed further below. The impacts of these decreases were partially offset by the impacts of impairment losses recognized in the prior period; these impairments are also discussed further below. The change to net income also reflects changes in Adjusted EBITDA, which are summarized below and discussed in more detail in “Segment Operating Results.”

Adjusted EBITDA (consolidated). For the three and nine months ended September 30, 2023 compared to the same periods last year, Adjusted EBITDA increased $453 million and $440 million, respectively, primarily driven by increases in our NGL and refined products transportation and services segment and our crude oil transportation and services segment, partially offset by the impact of unfavorable natural gas and NGL prices in our midstream segment. The decrease in Adjusted EBITDA from our midstream segment was partially offset by increases in Adjusted EBITDA from multiple other segments.

Additional discussion on the changes impacting net income and Adjusted EBITDA for the three and nine months ended September 30, 2023 compared to the same periods last year is available below and in “Segment Operating Results.”

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased for the three and nine months ended September 30, 2023 compared to the same periods last year primarily due to additional depreciation and amortization from assets recently placed in service and recent acquisitions.

Interest Expense, net of interest capitalized. Interest expense, net of interest capitalized, increased for the three and nine months ended September 30, 2023 compared to the same periods last year primarily due to higher interest rates on floating rate debt.

Income Tax Expense. For the three months ended September 30, 2023 compared to the same period last year, income tax expense decreased due to higher tax expense in the prior period associated with the sale of Energy Transfer Canada. For the nine months ended September 30, 2023 compared to the same period last year, income tax expense increased due to higher earnings from the Partnership’s consolidated corporate subsidiaries.

Impairment Losses and Other. For the three months ended September 30, 2023, impairment losses and other included a total of $1 million recognized by USAC related to its compression equipment. For the nine months ended September 30, 2023, impairment losses and other included a total of $12 million recognized by USAC related to its compression equipment.

For the three months ended September 30, 2022, impairment losses and other included an $85 million loss on the deconsolidation of Energy Transfer Canada, which was recorded upon the completion of the sale in August 2022. The nine months ended September 30, 2022 amount also included a $300 million impairment related to Energy Transfer Canada's assets recorded in March 2022 based on the anticipated proceeds from the expected sale of those assets. The remainder of impairment losses and other for the three and nine months ended September 30, 2022 were from USAC's recognition of impairment losses related to its compression equipment.

Gains on Interest Rate Derivatives. Gains on interest rate derivatives resulted from changes in forward interest rates, which caused our forward-starting swaps to change in value. The magnitude of the gains during the respective periods also reflected higher aggregate notional amount of interest rate swaps outstanding in the prior period.

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," 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 reserves 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, 2023, an increase in fuel prices reduced the lower of cost or market reserve requirements for the period by a net of $141 million, resulting in a favorable impact to net income. For the three months ended September 30, 2022, a decrease in fuel prices increased the lower of cost or market reserve requirements for the period by a net of $40 million, resulting in unfavorable impacts to net income. For the nine months ended September 30, 2023 and 2022, an increase in fuel prices reduced the lower of cost or market reserve requirements for the period by a net of $113 million and $81 million, respectively, resulting in favorable impacts to net income.

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."

Non-Operating Litigation-Related Loss. Non-operating litigation-related loss recognized in the three and nine months ended September 30, 2023 represents the estimated contingent loss associated with the Williams Litigation, which is discussed in Note 10 to our consolidated financial statements included in "Item 1. Financial Statements."

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

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,		
	2023	2022	Change	2023	2022	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$ 39	$ 36	$ 3	$ 110	$ 109	$ 1
MEP	21	(1)	22	68	(7)	75
White Cliffs	2	—	2	5	1	4
Explorer	10	8	2	27	17	10
Other	31	25	6	76	66	10
Total equity in earnings of unconsolidated affiliates	$ 103	$ 68	$ 35	$ 286	$ 186	$ 100
Adjusted EBITDA related to unconsolidated affiliates[1]:						
Citrus	$ 86	$ 86	$ —	$ 250	$ 245	$ 5
MEP	30	8	22	94	19	75
White Cliffs	7	5	2	19	15	4
Explorer	16	12	4	42	28	14
Other	43	36	7	109	102	7
Total Adjusted EBITDA related to unconsolidated affiliates	$ 182	$ 147	$ 35	$ 514	$ 409	$ 105
Distributions received from unconsolidated affiliates:						
Citrus	$ 53	$ 52	$ 1	$ 123	$ 133	$ (10)
MEP	25	4	21	89	14	75
White Cliffs	7	5	2	18	15	3
Explorer	10	6	4	29	20	9
Other	27	27	—	72	66	6
Total distributions received from unconsolidated affiliates	$ 122	$ 94	$ 28	$ 331	$ 248	$ 83

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

Segment Operating Results

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

The following tables 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.

The following analysis of segment operating results includes a measure of segment margin. 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 following sections 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.

Intrastate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Natural gas transported (BBtu/d)	15,123	14,878	245	15,011	14,565	446
Withdrawals from storage natural gas inventory (BBtu)	—	—	—	8,400	21,858	(13,458)
Revenues	$ 973	$ 2,383	$ (1,410)	$ 3,070	$ 6,218	$ (3,148)
Cost of products sold	664	1,994	(1,330)	2,119	5,008	(2,889)
Segment margin	309	389	(80)	951	1,210	(259)
Unrealized losses on commodity risk management activities	14	12	2	144	17	127
Operating expenses, excluding non-cash compensation expense	(71)	(93)	22	(207)	(251)	44
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(12)	(1)	(38)	(37)	(1)
Adjusted EBITDA related to unconsolidated affiliates	6	5	1	19	18	1
Other	(1)	—	(1)	—	6	(6)
Segment Adjusted EBITDA	$ 244	$ 301	$ (57)	$ 869	$ 963	$ (94)

Volumes. For the three months ended September 30, 2023 compared to the same periods last year, transported volumes increased primarily due to increased utilization on our Texas intrastate assets. For the nine months ended September 30, 2023 compared to the same period last year, transported volumes increased primarily due to increased utilization on the Enable Oklahoma Intrastate Transmission system and the Texas system, as well as higher production in the Haynesville Shale.

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,		
	2023	2022	Change	2023	2022	Change
Transportation fees	$ 211	$ 202	$ 9	$ 636	$ 613	$ 23
Natural gas sales and other (excluding unrealized gains and losses)	65	139	(74)	311	423	(112)
Retained fuel revenues (excluding unrealized gains and losses)	19	59	(40)	49	150	(101)
Storage margin (excluding unrealized gains and losses and fair value inventory adjustments)	28	—	28	99	40	59
Unrealized losses on commodity risk management activities and fair value inventory adjustments	(14)	(11)	(3)	(144)	(16)	(128)
Total segment margin	$ 309	$ 389	$ (80)	$ 951	$ 1,210	$ (259)

Segment Adjusted EBITDA. For the three months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $74 million in realized natural gas sales and other primarily due to lower pipeline optimization; and
- a decrease of $40 million in retained fuel revenues related to lower natural gas prices; partially offset by
- an increase of $28 million in storage margin primarily due to favorable storage optimization;
- a decrease of $22 million in operating expenses primarily due to a $21 million decrease in cost of fuel consumption from lower natural gas prices and a $2 million decrease due to lower utility pricing; and
- an increase of $9 million in transportation fees primarily due to new contracts on our Texas system and Haynesville assets.

Segment Adjusted EBITDA. For the nine months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $112 million in realized natural gas sales and other primarily due to lower pipeline optimization; and
- a decrease of $101 million in retained fuel revenues related to lower natural gas prices; partially offset by
- an increase of $59 million in storage margin primarily due to higher storage optimization;
- a decrease of $44 million in operating expenses primarily due to a $53 million decrease in cost of fuel consumption from lower natural gas prices, partially offset by a $4 million increase from recently acquired assets, a $2 million increase in ad valorem taxes and a $3 million increase in employee costs; and
- an increase of $23 million in transportation fees primarily due to new contracts on our Texas system and Haynesville assets.

Interstate Transportation and Storage

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Change	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	Change
Natural gas transported (BBtu/d)	16,237	14,157	2,080	16,424	14,359	2,065
Natural gas sold (BBtu/d)	40	28	12	27	30	(3)
Revenues	$ 571	$ 549	$ 22	$ 1,755	$ 1,645	$ 110
Cost of products sold	2	3	(1)	5	24	(19)
Segment margin	569	546	23	1,750	1,621	129
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(178)	(219)	41	(567)	(590)	23
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(30)	(37)	7	(89)	(100)	11
Adjusted EBITDA related to unconsolidated affiliates	129	106	23	374	293	81
Other	1	13	(12)	—	35	(35)
Segment Adjusted EBITDA	$ 491	$ 409	$ 82	$ 1,468	$ 1,259	$ 209

Volumes. For the three and nine months ended September 30, 2023 compared to the same periods last year, transported volumes increased primarily due to our Gulf Run system being placed in service in December 2022, as well as more capacity sold and higher utilization on our Transwestern, Rover, Panhandle and Trunkline systems due to increased demand.

Segment Adjusted EBITDA. For the three months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $23 million in segment margin primarily due to a $44 million increase resulting from our Gulf Run system being placed in service in December 2022, as well as a $28 million increase in transportation revenue from several of our interstate pipelines due to higher contracted volumes and higher interruptible utilization. These increases were partially offset by a $23 million decrease due to lower rates on our Panhandle system resulting from a FERC order in a rate case and a $27 million decrease primarily due to lower operational gas sales resulting from lower prices;
- a decrease of $41 million in operating expenses primarily due to a decrease from the revaluation of system gas;
- a decrease of $7 million in selling, general and administrative expenses primarily due to lower employee-related costs and professional fees; and
- an increase of $23 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to an increase from our Midcontinent Express Pipeline joint venture due to capacity sold at higher rates; partially offset by
- a decrease of $12 million in other items primarily due to the recognition in the prior period of amounts related to a shipper bankruptcy.

For the nine months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $129 million in segment margin primarily due to a $97 million increase resulting from our Gulf Run system being placed in service in December 2022, a $49 million increase in transportation revenue from several of our interstate pipeline systems due to higher contracted volumes and higher rates, an $18 million increase related to a shipper bankruptcy, a $13 million increase in parking and storage revenue and a $5 million increase in interruptible utilization. These increases were partially offset by a $22 million decrease due to lower operational gas sales resulting from lower prices, a $23 million decrease due to lower rates on our Panhandle system resulting from a FERC order in a rate case and an $8 million decrease in liquids revenue due to lower prices;
- a decrease of $23 million in operating expenses primarily due to a $46 million decrease from the revaluation of system gas, partially offset by $19 million of incremental expenses from our Gulf Run system being placed in service in December 2022;

- a decrease of $11 million in selling, general and administrative expenses primarily due to lower professional fees and employee-related costs; and
- an increase of $81 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to an increase of $75 million from our Midcontinent Express Pipeline joint venture as a result of higher revenue due to capacity sold at higher rates and a $5 million increase from our Southeast Supply Header joint venture as a result of higher revenue due to increased capacity sold at higher rates; partially offset by
- a decrease of $35 million in other items primarily due to the recognition in the prior period of certain amounts related to shipper bankruptcies.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Gathered volumes (BBtu/d)	19,825	19,107	718	19,808	18,264	1,544
NGLs produced (MBbls/d)	869	814	55	848	795	53
Equity NGLs (MBbls/d)	42	43	(1)	41	44	(3)
Revenues	$ 2,777	$ 4,871	$ (2,094)	$ 7,999	$ 13,846	$ (5,847)
Cost of products sold	1,808	3,678	(1,870)	5,124	10,418	(5,294)
Segment margin	969	1,193	(224)	2,875	3,428	(553)
Operating expenses, excluding non-cash compensation expense	(294)	(275)	(19)	(890)	(768)	(122)
Selling, general and administrative expenses, excluding non-cash compensation expense	(50)	(55)	5	(152)	(140)	(12)
Adjusted EBITDA related to unconsolidated affiliates	5	5	—	14	20	(6)
Other	1	—	1	4	38	(34)
Segment Adjusted EBITDA	$ 631	$ 868	$ (237)	$ 1,851	$ 2,578	$ (727)

Volumes. For the three and nine months ended September 30, 2023 compared to the same periods last year, gathered volumes and NGL production increased primarily due to increased producer activity in most regions.

Segment Margin. The table below presents the components of our midstream segment margin. For the three and nine months ended September 30, 2022, the amounts previously reported for fee-based and non-fee-based margin have been adjusted to reflect the reclassification of certain amounts to conform to the current period presentation; these changes did not impact total segment margin.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Gathering and processing fee-based revenues	$ 772	$ 772	$ —	$ 2,299	$ 2,175	$ 124
Non-fee-based contracts and processing (excluding unrealized gains and losses)	197	421	(224)	576	1,253	(677)
Total segment margin	$ 969	$ 1,193	$ (224)	$ 2,875	$ 3,428	$ (553)

Segment Adjusted EBITDA. For the three months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net impacts of the following:

- a decrease of $224 million in non-fee-based margin due to lower natural gas prices of $157 million and lower NGL prices of $68 million; and
- an increase of $19 million in operating expenses due to a $9 million increase in employee costs, a $7 million increase in maintenance, repairs and projects, including trucking and compression needs coupled with pricing increases, and a $6 million increase in ad valorem taxes due to growth and acquisitions; partially offset by

- a decrease of $5 million in selling, general and administrative expenses primarily due to lower insurance costs.

For the nine months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net impacts of the following:

- a decrease of $691 million in non-fee-based margin due to lower natural gas prices of $420 million and lower NGL prices of $271 million;
- an increase of $122 million in operating expenses due to a $44 million increase in services and material, including repairs, compliance and pricing, a $29 million increase in employee costs, a $17 million increase from the acquisition of Woodford Express and our new plants coming online, a $13 million increase from trucking and rental pricing and usage, a $10 million increase in ad valorem taxes and a $6 million increase in environmental reserves;
- an increase of $12 million in selling, general and administrative expenses primarily due to higher corporate allocations and legal expenses;
- a decrease of $6 million in Adjusted EBITDA related to unconsolidated affiliates due to the sale of the Partnership's membership interest in Ranch Westex JV LLC in 2022; and
- a decrease of $34 million in other items primarily due to the realization in the prior period of certain amounts related to a shipper bankruptcy; partially offset by
- an increase of $14 million in non-fee-based margin due to increased processed volumes in the Permian and South Texas regions; and
- an increase of $124 million in fee-based margin due to the Woodford Express acquisition in September 2022, as well as increased producer activity across all regions.

NGL and Refined Products Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
NGL transportation volumes (MBbls/d)	2,161	1,892	269	2,101	1,852	249
Refined products transportation volumes (MBbls/d)	551	543	8	535	522	13
NGL and refined products terminal volumes (MBbls/d)	1,475	1,287	188	1,425	1,265	160
NGL fractionation volumes (MBbls/d)	1,029	940	89	985	895	90
Revenues	$ 5,260	$ 6,075	$ (815)	$ 15,864	$ 19,909	$ (4,045)
Cost of products sold	4,034	5,044	(1,010)	12,365	16,921	(4,556)
Segment margin	1,226	1,031	195	3,499	2,988	511
Unrealized (gains) losses on commodity risk management activities	84	(126)	210	34	(158)	192
Operating expenses, excluding non-cash compensation expense	(235)	(265)	30	(667)	(708)	41
Selling, general and administrative expenses, excluding non-cash compensation expense	(33)	(33)	—	(106)	(96)	(10)
Adjusted EBITDA related to unconsolidated affiliates	34	27	7	92	71	21
Segment Adjusted EBITDA	$ 1,076	$ 634	$ 442	$ 2,852	$ 2,097	$ 755

Volumes. For the three and nine months ended September 30, 2023 compared to the same periods last year, NGL transportation and terminal volumes increased primarily due to higher volumes from the Permian region, on our Mariner East pipeline system and on our export pipelines into our Nederland Terminal.

The increase in transportation volumes and the commissioning of our eighth fractionator in August 2023 also led to higher fractionated volumes at our Mont Belvieu, Texas fractionation facility for the three and nine months ended September 30, 2023 compared to the same periods last year.

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,		
	2023	2022	Change	2023	2022	Change
Transportation margin	$ 639	$ 553	$ 86	$ 1,778	$ 1,552	$ 226
Fractionators and refinery services margin	251	227	24	647	627	20
Terminal services margin	235	179	56	664	521	143
Storage margin	78	72	6	232	211	21
Marketing margin	107	(126)	233	212	(81)	293
Unrealized gains (losses) on commodity risk management activities	(84)	126	(210)	(34)	158	(192)
Total segment margin	$ 1,226	$ 1,031	$ 195	$ 3,499	$ 2,988	$ 511

Segment Adjusted EBITDA. For the three months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $233 million in marketing margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to gains during the 2023 period from the optimization of hedged NGL and refined product inventories as compared to losses from this activity during the 2022 period. Marketing margin also benefited from intrasegment charges of $7 million which are fully offset within our transportation margin;

- an increase of $86 million in transportation margin primarily due to a $41 million increase resulting from higher y-grade throughput and contractual rate escalations on our Texas pipeline system, a $26 million increase resulting from higher throughput on our Mariner East pipeline system, a $15 million increase from higher exported volumes feeding into our Nederland Terminal, a $13 million increase from higher throughput and contractual rate escalations on our refined product pipelines and a $2 million increase from higher throughput on our Mariner West pipeline. These increases were partially offset by intrasegment charges of $7 million and $6 million which are fully offset within our marketing and fractionation margins, respectively;

- an increase of $56 million in terminal services margin primarily due to a $34 million increase from our Marcus Hook Terminal due to contractual rate escalations and higher throughput, an $18 million increase from higher export volumes loaded at our Nederland Terminal and a $3 million increase due to increased tank leases at our Eagle Point terminal;

- a decrease of $30 million in operating expenses primarily due to a decrease in gas and power utility costs;

- an increase of $24 million in fractionators and refinery services margin due to a $17 million increase resulting from higher volumes, a $6 million intrasegment charge which is fully offset in our transportation margin and a $2 million increase from a more favorable pricing environment impacting our refinery services business;

- an increase of $7 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to higher volumes from certain joint venture pipelines; and

- an increase of $6 million in storage margin primarily due to a $10 million increase in fees generated from exported volumes. This increase was partially offset by a $3 million decrease from the timing of cavern withdrawals.

For the nine months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $293 million in marketing margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to higher gains during the 2023 period from the optimization of hedged NGL and refined product inventories, as compared to losses from this activity during the 2022 period. Marketing margin also benefited from intrasegment charges of $19 million which are fully offset within our transportation margin;

- an increase of $226 million in transportation margin primarily due to a $117 million increase resulting from higher y-grade throughput and contractual rate escalations on our Texas pipeline system, a $71 million increase resulting from higher throughput on our Mariner East pipeline system, a $33 million increase from higher exported volumes feeding into our Nederland Terminal, a $15 million increase from higher throughput and contractual rate escalations on our refined product pipelines, a $13 million increase from the timing of third-party deficiency payments on our Northeast region pipelines and a $9 million increase from higher throughput on our Mariner West pipeline. These increases were partially offset by intrasegment charges of $19 million and $12 million which are fully offset within our marketing and fractionation margins, respectively;

- an increase of $143 million in terminal services margin primarily due to an $89 million increase from our Marcus Hook Terminal due to contractual rate escalations and higher throughput, a $48 million increase from higher export volumes loaded at our Nederland Terminal and a $6 million increase primarily from higher throughput from our refined product marketing terminals;
- a decrease of $41 million in operating expenses primarily due to $70 million in savings from lower electricity prices, partially offset by a $15 million increase in employee costs and a $9 million increase in materials cost and contract and maintenance labor;
- an increase of $21 million in storage margin primarily due to fees generated from exported volumes;
- an increase of $21 million in Adjusted EBITDA related to unconsolidated affiliates due to higher volumes on certain joint venture pipelines; and
- an increase of $20 million in fractionators and refinery services margin primarily due to a $19 million increase resulting from higher volumes and a $12 million intrasegment charge which is fully offset in our transportation margin. These increases were partially offset by an $11 million decrease from a less favorable pricing environment impacting our refinery services business; partially offset by
- an increase of $10 million in selling, general and administrative expenses primarily due to a $7 million increase in overhead expenses and a $3 million increase in insurance costs.

Crude Oil Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Crude transportation volumes (MBbls/d)	5,640	4,575	1,065	5,056	4,369	687
Crude terminal volumes (MBbls/d)	3,548	3,088	460	3,359	2,974	385
Revenues	$ 7,289	$ 6,416	$ 873	$ 19,322	$ 19,642	$ (320)
Cost of products sold	6,392	5,627	765	16,858	17,347	(489)
Segment margin	897	789	108	2,464	2,295	169
Unrealized (gains) losses on commodity risk management activities	14	2	12	26	(4)	30
Operating expenses, excluding non-cash compensation expense	(183)	(176)	(7)	(508)	(467)	(41)
Selling, general and administrative expenses, excluding non-cash compensation expense	(29)	(155)	126	(90)	(212)	122
Adjusted EBITDA related to unconsolidated affiliates	6	1	5	12	3	9
Other	1	—	1	2	1	1
Segment Adjusted EBITDA	$ 706	$ 461	$ 245	$ 1,906	$ 1,616	$ 290

Volumes. For the three and nine months ended September 30, 2023 compared to the same periods last year, crude transportation volumes were higher on our Texas pipeline system due to higher Permian crude oil production, higher gathered volumes and contributions from assets acquired in 2023. Volumes on our Bakken Pipeline were also higher, driven by continuing crude oil production growth in the Bakken. Volumes on our Bayou Bridge Pipeline were higher for the nine months ended September 30, 2023, while relatively consistent for the three months ended September 30, 2023, due to continuing strong Gulf Coast refinery demand. Crude terminal volumes were higher due to growth in Permian and Bakken volumes, stronger Gulf Coast refinery utilization and contributions from assets acquired in 2023.

Segment Adjusted EBITDA. For the three months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased primarily due to the net impacts of the following:

- an increase of $120 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to an $81 million increase from recently acquired assets, a $36 million increase from higher volumes on our Bakken Pipeline and a $33 million increase from higher volumes on our Texas crude pipeline system, partially offset by a $20 million decrease at our Gulf Coast terminals due to timing of oil gain sales in the prior period as well as a $9 million decrease from our crude oil acquisition and marketing business primarily due to lower refined product sales margins and higher affiliate fees paid due to higher volumes transported;
- a decrease of $126 million in selling, general and administrative expenses primarily due to a charge related to a legal matter in the prior period; and
- an increase of $5 million in Adjusted EBITDA related to unconsolidated affiliates due to assets acquired; partially offset by
- an increase of $7 million in operating expenses primarily due to a $21 million increase from assets acquired, partially offset by a $9 million decrease in ad valorem taxes.

For the nine months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased primarily due to the net impacts of the following:

- an increase of $199 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $131 million increase from recently acquired assets, an $85 million increase from higher volumes on our Bakken Pipeline and a $65 million increase from higher volumes on our Texas crude pipeline system, partially offset by a $100 million decrease from our crude oil acquisition and marketing business due primarily to lower refined product sales margins and higher affiliate fees paid due to higher volumes transported;
- a decrease of $122 million in selling, general and administrative expenses primarily due to a charge related to a legal matter in the prior period; and
- an increase of $9 million in Adjusted EBITDA related to unconsolidated affiliates due to assets acquired; partially offset by
- an increase of $41 million in operating expenses primarily due to a $37 million increase from assets acquired.

Investment in Sunoco LP

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Revenues	$ 6,320	$ 6,594	$ (274)	$ 17,427	$ 19,811	$ (2,384)
Cost of products sold	5,793	6,261	(468)	16,211	18,703	(2,492)
Segment margin	527	333	194	1,216	1,108	108
Unrealized (gains) losses on commodity risk management activities	(1)	23	(24)	(11)	3	(14)
Operating expenses, excluding non-cash compensation expense	(110)	(98)	(12)	(310)	(293)	(17)
Selling, general and administrative expenses, excluding non-cash compensation expense	(28)	(29)	1	(83)	(78)	(5)
Adjusted EBITDA related to unconsolidated affiliates	2	2	—	8	7	1
Inventory valuation adjustments	(141)	40	(181)	(113)	(81)	(32)
Other	8	5	3	21	15	6
Segment Adjusted EBITDA	$ 257	$ 276	$ (19)	$ 728	$ 681	$ 47

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

Segment Adjusted EBITDA. For the three months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment decreased primarily due to the net impacts of the following:

- a decrease in the profit on motor fuel sales of $22 million primarily due to a 7% decrease in profit per gallon sold, partially offset by an increase in gallons sold; and
- an increase in operating costs of $11 million, including other operating expense, general and administrative expense and lease expense, primarily due to higher costs as a result of acquisitions of refined product terminals and the transmix processing and terminal facility; partially offset by
- an increase in non-motor fuel sales and lease profit of $12 million primarily due to increased throughput and storage margin from recent acquisitions and increased rental income.

For the nine months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment increased primarily due to the net impacts of the following:

- an increase in the gross profit on motor fuel sales of $42 million primarily due to a 6.9% increase in gallons sold; and
- an increase in non-motor fuel sales and lease profit of $24 million primarily due to increased throughput and storage margin from recent acquisitions and increased rental income; partially offset by
- an increase in operating costs of $22 million, including other operating expense, general and administrative expense and lease expense, primarily due to higher costs as a result of acquisitions of refined product terminals and the transmix processing and terminal facility.

Investment in USAC

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Revenues	$ 217	$ 179	$ 38	$ 621	$ 514	$ 107
Cost of products sold	35	28	7	104	78	26
Segment margin	182	151	31	517	436	81
Operating expenses, excluding non-cash compensation expense	(39)	(31)	(8)	(107)	(90)	(17)
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(11)	(2)	(37)	(33)	(4)
Segment Adjusted EBITDA	$ 130	$ 109	$ 21	$ 373	$ 313	$ 60

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

Segment Adjusted EBITDA. For the three months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment increased primarily due to the net impacts of the following:

- an increase of $31 million in segment margin primarily due to higher revenue-generating horsepower as a result of increased demand for compression services, higher market-based rates on newly deployed and redeployed compression units and higher average rates on existing customer contracts; partially offset by
- an increase of $8 million in operating expenses primarily due to higher employee costs associated with increased revenue-generating horsepower as well as higher parts and service costs.

For the nine months ended September 30, 2023 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment increased primarily due to the net impacts of the following:

- an increase of $81 million in segment margin primarily due to higher revenue-generating horsepower as a result of increased demand for compression services, higher market-based rates on newly deployed and redeployed compression units and higher average rates on existing customer contracts; partially offset by
- an increase of $17 million in operating expenses primarily due to higher employee costs associated with increased revenue-generating horsepower as well as higher parts and service costs.

All Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	Change	2023	2022	Change
Revenues	$ 444	$ 1,084	$ (640)	$ 1,387	$ 2,761	$ (1,374)
Cost of products sold	457	1,052	(595)	1,354	2,548	(1,194)
Segment margin	(13)	32	(45)	33	213	(180)
Unrealized (gains) losses on commodity risk management activities	(4)	13	(17)	(11)	12	(23)
Operating expenses, excluding non-cash compensation expense	(8)	(17)	9	(18)	(75)	57
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(11)	(2)	(33)	(44)	11
Adjusted EBITDA related to unconsolidated affiliates	2	2	—	3	3	—
Other and eliminations	42	11	31	75	40	35
Segment Adjusted EBITDA	$ 6	$ 30	$ (24)	$ 49	$ 149	$ (100)

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, until those assets were divested in August 2022.

Segment Adjusted EBITDA. For the three months ended September 30, 2023 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 $11 million due to the sale of Energy Transfer Canada in 2022;
- a decrease of $10 million due to less favorable power trading market conditions; and
- a decrease of $7 million from our dual drive compression business due to lower gas prices and increased competition; partially offset by
- an increase of $5 million due to higher margin from sales in our compressor business.

For the nine months ended September 30, 2023 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 $80 million due to the sale of Energy Transfer Canada in 2022;
- a decrease of $19 million from our dual drive compression business due to lower gas prices and increased competition; and
- a decrease of $16 million due to less favorable power trading market conditions due to lower volatility; partially offset by
- an increase of $20 million due to higher margin from sales in our compressor business.

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 2023 to be within the following ranges (including only our proportionate share for joint ventures and excluding capital expenditures related to our investments in Sunoco LP and USAC):

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 50	$ 75	$ 30	$ 40
Interstate transportation and storage	250	300	160	170
Midstream	825	850	245	255
NGL and refined products transportation and services	575	625	120	130
Crude oil transportation and services	175	200	130	135
All other (including eliminations)	25	50	55	60
Total capital expenditures	$ 1,900	$ 2,100	$ 740	$ 790

The Partnership expects its growth capital expenditures will be between $2 billion and $3 billion per year in future periods.

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 capital expenditures and distributions with cash flows from operating activities.

Sunoco LP currently expects to spend approximately $65 million in maintenance capital and at least $150 million in growth capital for the full year 2023.

USAC currently plans to spend approximately $26 million in maintenance capital expenditures and spend between $270 million and $280 million in expansion capital expenditures for the full year 2023.

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, 2023 compared to nine months ended September 30, 2022. Cash provided by operating activities during 2023 was $8.26 billion compared to $7.71 billion for 2022, and net income was $3.73 billion for 2023 and $4.43 billion for 2022. The difference between net income and net cash provided by operating activities for the nine months ended September 30, 2023 primarily consisted of net changes in operating assets and liabilities (net of effects of acquisitions and divestitures) of $1.18 billion and non-cash items totaling $3.11 billion.

The non-cash activity in 2023 and 2022 consisted primarily of depreciation, depletion and amortization of $3.23 billion and $3.10 billion, respectively, non-cash compensation expense of $99 million and $88 million, respectively, favorable inventory valuation adjustments of $113 million and $81 million, respectively, deferred income taxes of $187 million and $158 million, respectively, and impairment losses and other of $12 million and $386 million, respectively. Net income also included equity in earnings of unconsolidated affiliates of $286 million and $186 million in 2023 and 2022, respectively.

Cash provided by operating activities includes cash distributions received from unconsolidated affiliates that are deemed to be paid from cumulative earnings, which distributions were $286 million in 2023 and $182 million in 2022.

Cash paid for interest, net of interest capitalized, was $1.54 billion and $1.48 billion for the nine months ended September 30, 2023 and 2022, respectively. Interest capitalized was $53 million and $84 million for the nine months ended September 30, 2023 and 2022, 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, 2023 compared to nine months ended September 30, 2022. Cash used in investing activities during 2023 was $3.36 billion compared to $3.08 billion for 2022. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2023 were $2.39 billion compared to $2.44 billion for 2022. Additional detail related to our capital expenditures is provided in the following table.

In 2023, we paid $930 million in cash for the Lotus Midstream acquisition and Sunoco LP paid $111 million in cash for the acquisition of 16 refined product terminals from Zenith Energy. In 2022, we paid $485 million in cash for the acquisition of Woodford Express, LLC, we paid $325 million in cash for the acquisition of Caliche Coastal Holdings, LLC (subsequently renamed Energy Transfer Spindletop LLC) and Sunoco LP paid $252 million in cash related to its acquisition of a transmix processing and terminal facility. In 2022, we received $302 million in cash from the sale of our interest in Energy Transfer Canada.

The following is a summary of capital expenditures (including only our proportionate share for joint ventures, net of contributions in aid of construction costs) on an accrual basis for the nine months ended September 30, 2023:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$ 47	$ 38	$ 85
Interstate transportation and storage	172	111	283
Midstream	498	165	663
NGL and refined products transportation and services	399	89	488
Crude oil transportation and services	69	98	167
Investment in Sunoco LP	95	37	132
Investment in USAC	185	19	204
All other (including eliminations)	27	44	71
Total capital expenditures	$ 1,492	$ 601	$ 2,093

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, 2023 compared to nine months ended September 30, 2022. Cash used in financing activities during 2023 was $4.64 billion compared to $4.65 billion for 2022. During 2023, we had a net decrease in our debt level of $183 million compared to a net decrease of $1.71 billion for 2022. In 2023 and 2022, we paid debt issuance costs of $12 million and $9 million, respectively.

In 2023 and 2022, we paid distributions of $3.12 billion and $2.12 billion, respectively, to our partners. In 2023 and 2022, we paid distributions of $1.29 billion and $1.18 billion, respectively, to noncontrolling interests. In 2023 and 2022, we paid distributions of $37 million in both periods to our redeemable noncontrolling interests.

In 2023 and 2022, we received capital contributions of $3 million and $404 million, respectively, in cash from noncontrolling interests.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2023	December 31, 2022
Energy Transfer Indebtedness:		
Notes and Debentures[1] [2]	$ 37,043	$ 39,468
Five-Year Credit Facility[2]	2,847	793
Subsidiary Indebtedness:		
Transwestern Senior Notes	250	250
Bakken Project Senior Notes	1,850	1,850
Sunoco LP Senior Notes and lease-related obligations[2]	3,194	2,694
USAC Senior Notes	1,475	1,475
HFOTCO Tax Exempt Bonds[2]	—	225
Sunoco LP Credit Facility[2]	647	900
USAC Credit Facility	813	646
Other long-term debt	29	3
Net unamortized premiums, discounts, and fair value adjustments	145	183
Deferred debt issuance costs	(212)	(225)
Total debt	48,081	48,262
Less: current maturities of long-term debt[3]	1,006	2
Long-term debt, less current maturities	$ 47,075	$ 48,260

(1) As of September 30, 2023, this balance included a total of $4.31 billion aggregate principal amount of senior notes due on or before September 30, 2024, which were classified as long-term as management has the intent and ability to refinance the borrowings on a long-term basis.

(2) See additional information below under “Recent Transactions.”

(3) As of September 30, 2023, current maturities of long-term debt reflected on the Partnership’s consolidated balance sheet includes $1.00 billion of senior notes issued by the Bakken Pipeline entities which mature in April 2024. The Partnership’s proportional ownership in the Bakken Pipeline entities is 36.4%.

Recent Transactions

Senior Notes

On November 1, 2023, the Partnership redeemed $600 million aggregate principal amount of its 4.50% Senior Notes due November 1, 2023 using proceeds from the senior notes offering discussed in the following paragraph.

In October 2023, the Partnership issued $1.00 billion aggregate principal amount of 6.05% Senior Notes due 2026, $500 million aggregate principal amount of 6.10% Senior Notes due 2028, $1.00 billion aggregate principal amount of 6.40% Senior Notes due 2030 and $1.50 billion aggregate principal amount of 6.55% Senior Notes due 2033. The Partnership intends to use the net proceeds to refinance existing indebtedness, including borrowings under its Five-Year Credit Facility (defined below) and for general partnership purposes.

In the third quarter of 2023, the Partnership redeemed $500 million aggregate principal amount of its 4.20% Senior Notes due September 2023 using proceeds from its Five-Year Credit Facility.

In the first quarter of 2023, the Partnership redeemed $350 million aggregate principal amount of its 3.45% Senior Notes due January 2023, $800 million aggregate principal amount of its 3.60% Senior Notes due February 2023 and $1.00 billion aggregate principal amount of its 4.25% Senior Notes due March 2023 using proceeds from its Five-Year Credit Facility.

HFOTCO Debt

In May 2023, the Partnership refinanced all of the $225 million outstanding principal amount of HFOTCO tax-exempt bonds with new 10-year tax-exempt bonds. The new bonds, which were issued through the Harris County Industrial Development Corporation and are obligations of Energy Transfer, accrue interest at a fixed rate of 4.05% and are mandatorily redeemable in 2033. Upon redemption, these tax-exempt bonds may be remarketed on different terms through final maturity of November 1, 2050.

Sunoco LP Senior Notes Offering

In September 2023, Sunoco LP issued $500 million aggregate principal amount of 7.00% senior notes due 2028 in a private placement to eligible purchasers. The net proceeds from this offering were used to repay a portion of Sunoco LP's existing borrowings under its credit facility.

Credit Facilities and Commercial Paper

Five-Year Credit Facility

The Partnership's revolving credit facility (the "Five-Year Credit Facility") allows for unsecured borrowings up to $5.00 billion and matures in April 2027. The Five-Year Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased up to $7.00 billion under certain conditions.

As of September 30, 2023, the Five-Year Credit Facility had $2.85 billion of outstanding borrowings, of which $1,547 million consisted of commercial paper. The amount available for future borrowings was $2.12 billion, after accounting for outstanding letters of credit in the amount of $32 million. The weighted average interest rate on the total amount outstanding as of September 30, 2023 was 6.29%.

Sunoco LP Credit Facility

As of September 30, 2023, Sunoco LP's credit facility had $647 million of outstanding borrowings and $6 million in standby letters of credit and matures in April 2027. The amount available for future borrowings at September 30, 2023 was $847 million. The weighted average interest rate on the total amount outstanding as of September 30, 2023 was 7.34%.

USAC Credit Facility

As of September 30, 2023, USAC's credit facility, which matures in December 2026, had $813 million of outstanding borrowings and no outstanding letters of credit. As of September 30, 2023, USAC had $787 million of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $434 million. The weighted average interest rate on the total amount outstanding as of September 30, 2023 was 7.99%.

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, 2023.

CASH DISTRIBUTIONS

Cash Distributions Paid by Energy Transfer

Under its Partnership Agreement, Energy Transfer 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 to provide for future cash requirements.

Cash Distributions on Energy Transfer Common Units

Distributions declared and/or paid with respect to Energy Transfer common units subsequent to December 31, 2022 were as follows:

Quarter Ended	Record Date	Payment Date	Rate	
December 31, 2022	February 7, 2023	February 21, 2023	$	0.3050
March 31, 2023	May 8, 2023	May 22, 2023		0.3075
June 30, 2023	August 14, 2023	August 21, 2023		0.3100
September 30, 2023	October 30, 2023	November 20, 2023		0.3125

Cash Distributions on Energy Transfer Preferred Units

Distributions declared on the Energy Transfer Preferred Units were as follows:

Period Ended	Record Date	Payment Date	Series A[(1)]	Series B[(2)]	Series C[(1)]	Series D[(1)]	Series E	Series F[(2)]	Series G[(2)]	Series H[(2)]
December 31, 2022	February 1, 2023	February 15, 2023	$ 31.250	$ 33.125	$ 0.4609	$ 0.4766	$ 0.475	$ —	$ —	$ —
March 31, 2023	May 1, 2023	May 15, 2023	21.982	—	0.4609	0.4766	0.475	33.750	35.625	32.500
June 30, 2023	August 1, 2023	August 15, 2023	23.891	33.125	0.6294	0.4766	0.475	—	—	—
September 30, 2023	November 1, 2023	November 15, 2023	24.672	—	0.6489	0.6622	0.4750	33.75	35.625	32.50

(1) See additional information on Series A, Series C and Series D distributions below.

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

Prior to February 15, 2023, distributions on the Series A Preferred Units accrued at a fixed rate of 6.250% per annum of the liquidation preference of $1,000. Beginning February 15, 2023 to, but excluding, August 15, 2023, the Series A Preferred Units accrued a floating distribution rate set each quarterly distribution period at a percentage of the $1,000 liquidation preference equal to the then-current three-month LIBOR plus a spread of 4.028% per annum. Beginning August 15, 2023, the floating distribution rate on the Series A Preferred Units is based on three-month SOFR, plus a tenor spread adjustment of 0.26161%, plus 4.028% per annum. Distributions on Series A Preferred Units were previously payable semiannually in arrears until February 15, 2023, and, after February 15, 2023, quarterly in arrears, when, as, and if declared by our General Partner out of legally available funds for such purpose.

Prior to May 15, 2023, distributions on the Series C Preferred Units accrued at a fixed rate of 7.375% per annum of the liquidation preference of $25. Beginning May 15, 2023 to, but excluding, August 15, 2023, the Series C Preferred Units accrued a floating distribution rate set each quarterly distribution period at a percentage of the $25 liquidation preference equal to the then-current three-month LIBOR plus a spread of 4.530% per annum. On and after August 15, 2023, the floating distribution rate on the Series C Preferred Units is based on the three-month SOFR, plus a tenor spread adjustment of 0.26161%, plus 4.530% per annum.

Prior to August 15, 2023, distributions on the Series D Preferred Units accrued at a fixed rate of 7.625% per annum of the liquidation preference of $25. On and after August 15, 2023, the Series D Preferred Units accrue a floating distribution rate set each quarterly distribution period at a percentage of the $25 liquidation preference equal to the three-month SOFR, plus a tenor spread adjustment of 0.26161%, plus 4.738% per annum.

Distributions on the Series B Preferred Units and Series E Preferred Units are scheduled to begin accruing at a floating rate as follows:

	Beginning of floating rate period	Applicable Spread	Tenor spread adjustment	Floating rate
Series B Preferred Units	February 15, 2028	4.155 %	0.26161 %	Three-month SOFR
Series E Preferred Units	May 15, 2024	5.161 %	0.26161 %	Three-month SOFR

Description of Energy Transfer Preferred Units

A summary of the distribution and redemption rights associated with the Energy Transfer 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 master limited partnerships, as well as other non-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 common units declared and/or paid by Sunoco LP subsequent to December 31, 2022 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2022	February 7, 2023	February 21, 2023	$ 0.8255
March 31, 2023	May 8, 2023	May 22, 2023	0.8420
June 30, 2023	August 14, 2023	August 21, 2023	0.8420
September 30, 2023	October 30, 2023	November 20, 2023	0.8420

Cash Distributions Paid by USAC

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2022 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2022	January 23, 2023	February 3, 2023	$ 0.525
March 31, 2023	April 24, 2023	May 5, 2023	0.525
June 30, 2023	July 24, 2023	August 4, 2023	0.525
September 30, 2023	October 23, 2023	November 3, 2023	0.525

CRITICAL ACCOUNTING ESTIMATES

The Partnership's critical accounting estimates are described in its Annual Report on Form 10-K filed with the SEC on February 17, 2023. We have not made any changes to the accounting policies involving critical accounting estimates subsequent to the Form 10-K filing. Changes to any of the related estimate amounts are discussed in the notes to consolidated financial statements included in "Item 1. Financial Statements" in this quarterly report on Form 10-Q.

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 ability of our subsidiaries to make cash distributions to us, which is dependent on their results of operations, cash flows and financial condition;
- the actual amount of cash distributions by our subsidiaries to us;

- the volumes transported on our subsidiaries' pipelines and gathering systems;
- the level of throughput in our subsidiaries' processing and treating facilities;
- the fees our subsidiaries 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;
- 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 subsidiaries' 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 subsidiaries pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our subsidiaries liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our subsidiaries' customers;
- risks related to the development of new infrastructure projects or other growth projects, including failure to make sufficient progress to justify continued development, delays in obtaining customers, increased costs of financing and regulatory, environmental, political and legal uncertainties that may affect the timing and cost of these projects;
- risks associated with the construction of new pipelines, treating and processing facilities or other facilities, or additions to our subsidiaries' existing pipelines and their 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 subsidiaries' 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 our subsidiaries own a noncontrolling interests, including risks related to management actions at such entities that our subsidiaries 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
- risks associated with a potential failure to successfully combine our business with that of Crestwood.

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" of our Annual Report on Form 10-K for the year ended December 31, 2022 filed with the SEC on February 17, 2023, "Part II — Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2023 filed with the SEC on August 3, 2023 and in this Quarterly Report on Form 10-Q. 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, 2022 filed with the SEC on February 17, 2023, 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, 2022. Since December 31, 2022, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The following table 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, 2023			December 31, 2022		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (BBtu):						
Fixed Swaps/Futures	330	$ —	$ —	145	$ —	$ —
Basis Swaps IFERC/NYMEX [(1)]	(44,800)	(6)	1	(39,563)	54	3
Power (Megawatt):						
Forwards	171,600	1	—	—	1	—
Futures	(74,391)	1	—	(21,384)	—	—
Options – Puts	68,800	—	—	119,200	—	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	48,393	(3)	2	42,440	(41)	4
Swing Swaps IFERC	(72,220)	(1)	2	(202,815)	63	7
Fixed Swaps/Futures	(4,803)	12	2	(15,758)	51	7
Forward Physical Contracts	(2,145)	3	1	2,423	8	1
NGLs (MBbls) – Forwards/Swaps	(14,238)	(50)	60	6,934	(41)	63
Crude (MBbls) – Forwards/Swaps	(7,660)	(9)	54	795	26	22
Refined Products (MBbls) – Futures	(5,751)	(8)	62	(3,547)	(39)	37
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(43,745)	2	1	(37,448)	22	2
Fixed Swaps/Futures	(43,745)	14	14	(37,448)	58	17

(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, 2023, we and our subsidiaries had $4.91 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $49 million annually. However, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of 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 (including USAC's), none of which are designated as hedges for accounting purposes (dollar amounts presented in millions):

		Notional Amount Outstanding	
Term	Type[(1)]	September 30, 2023	December 31, 2022
Energy Transfer:			
July 2024[(2)]	Forward-starting to pay an average fixed rate of 3.388% and receive a floating rate	$ —	$ 400
USAC:			
April 2025[(3)]	Pay a fixed rate of 3.785% and receive a floating rate (effective April 2023)	700	—

(1) Floating rates are based on SOFR.

(2) The July 2024 interest rate swaps were terminated and settled in August 2023.

(3) In October 2023, USAC modified its April 2025 interest rate swap. The termination date was extended from April 1, 2025 to December 31, 2025. Under the modified interest rate swap, USAC pays a fixed interest rate of 3.9725% and continues to receive floating interest rate payments that are indexed to the one-month SOFR.

A hypothetical change of 100 basis points in interest rates for USAC's interest rate swap 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 $11 million as of September 30, 2023. 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.

The Partnership also has outstanding Series A Preferred Units, Series C Preferred Units and Series D Preferred Units with aggregate liquidation preferences of $950 million, $ 450 million and $445 million, respectively, for which distributions are based on a floating rate beginning February 15, 2023 and May 15, 2023, respectively. A hypothetical change of 100 basis points in interest rates would result in a net change in preferred unit distributions of $18 million annually for the Series A Preferred Units, Series C Preferred Units and Series D Preferred Units in the aggregate.

As of September 30, 2023, the Partnership had $600 million of Floating Rate Junior Subordinated Notes outstanding, as well as the Series A Preferred Units, Series C Preferred Units and Series D Preferred Units, the floating rates for each of which were based on the three-month SOFR rate plus a 0.26161% tenor spread adjustment. Such tenor spread adjustment will be in addition to the applicable spread for each series of Preferred Units and Floating Rate Junior Subordinated Notes.

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 Officers) 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 Co-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, 2023 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 Co-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

On May 2, 2023, Energy Transfer acquired Lotus Midstream Operations, LLC ("Lotus Midstream"), and during the three months ended September 30, 2023, certain of Lotus Midstream's internal controls over financial reporting were impacted by changes made to conform to the existing controls and procedures of Energy Transfer.

None of the changes resulting from the Lotus Midstream acquisition were in response to any identified deficiency or weakness in our internal control over financial reporting. Other than changes resulting from the Lotus Midstream acquisition, 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, 2023 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 17, 2023 and Note 10 in "Item 1. Financial Statements" in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2023.

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 following environmental proceedings 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 $0.3 million.

On June 15, 2023, PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (collectively "NOPV"), CPF 4-2023-011-NOPV, identifying three probable violations with compliance order actions associated with two of them and civil penalties proposed in an amount totaling $2,473,912. The NOPV related to a PHMSA Accident Investigation Division investigation of a pigging incident which occurred on March 26, 2020 at the Partnership's Borcher Station in Kansas and resulted in a fatality. The Partnership challenged PHMSA's alleged violations and related civil penalties and compliance order actions contained in the NOPV, and requested an administrative hearing, which is set for April 24, 2024 before a PHMSA Presiding Official.

On August 31, 2023, the United States Department of Justice filed suit in the District Court for the Southern District of Texas (Corpus Christi Division) captioned as United States v. Energy Transfer (R&M), LLC et al. Civil Action No. 2:23-cv-214, against Sunoco and two other parties seeking to recover past CERCLA response costs allegedly incurred by U.S. EPA in excess of $500,000 and certain declaratory relief related to compliance. Suntide Refining Company (Sunoco as successor) is alleged to have arranged for the transport and disposal of refinery wastes containing hazardous substances at the Brine Service Company Superfund Site in Corpus Christi, Nueces County, TX. At this time, we cannot determine the likelihood of any liability in this matter; however, Sunoco intends to defend and dispute the allegations of the lawsuit, including but not limited to the joint and several liability determination sought. This lawsuit is included among the matters described in our discussion of our other environmental remediation matters. Please see "Part I. Item 1. Note 10. Regulatory Matters, Commitments, Contingencies and Environmental Liabilities - Environmental Matters – Environmental Remediation".

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 required in this Item, see disclosure under the headings "Litigation and Contingencies" and "Environmental Matters" in Note 10 to our consolidated financial statements 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, 2022 filed with the SEC on February 17, 2023 and from the risk factor described in "Part II – Item 1A. Risk Factors" in the Partnership's Quarterly Report on Form 10-Q for the quarter ended June 30, 2023 filed with the SEC on August 3, 2023.

The Crestwood acquisition may not be consummated, and, even if consummated, we may fail to successfully combine our businesses, which could have an adverse impact on our future results.

The Crestwood acquisition is expected to close in the fourth quarter of 2023 but is subject to the satisfaction of a number of conditions beyond our control that may prevent, delay or otherwise materially adversely affect the completion of the acquisition. We cannot predict with certainty whether and when these conditions will be satisfied. Any delay in completing the acquisition could cause us not to realize, or delay the realization of, some or all of the benefits that we expect to achieve from the acquisition. Furthermore, if the transaction is consummated, we may not be able to integrate Crestwood's business successfully into ours or to achieve anticipated synergies and value creation from the transaction, which could have an adverse impact on our results of operations.

ITEM 6. EXHIBITS

The exhibits listed on the following exhibit index are filed or furnished, as indicated, as part of this report:

Exhibit Number	Description
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)
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 3.1 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)
4.1	Second Supplemental Indenture, dated as of October 13, 2023, between Energy Transfer LP, as issuer, and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.2 of Form 8-K (File No. 1-32740) filed October 13, 2023)
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; (iv) our Consolidated Statements of Equity; (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

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 2, 2023

By: /s/ A. Troy Sturrock

A. Troy Sturrock

Group Senior Vice President, Controller and Principal Accounting Officer

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 2, 2023

/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 2, 2023

/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, Dylan A. Bramhall, 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 2, 2023

/s/ Dylan A. Bramhall

Dylan A. Bramhall
Group Chief Financial Officer

Exhibit 32.1

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

In connection with the quarterly report of Energy Transfer LP (the “Partnership”) on Form 10-Q for the quarter ended September 30, 2023, 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 2, 2023

/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, 2023, 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 2, 2023

/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, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Dylan A. Bramhall, 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 2, 2023

/s/ Dylan A. Bramhall
Dylan A. Bramhall
Group Chief Financial Officer

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