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 March 31, 2024

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**
7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	**ETprE**	**New York Stock Exchange**
9.250% Series I Fixed Rate Perpetual Preferred Units	**ETprI**	**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 May 3, 2024, the registrant had 3,370,023,318 Common Units outstanding.

FORM 10-Q
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
Crestwood	Crestwood Equity Partners LP, which was acquired by Energy Transfer in November 2023
Dakota Access	Dakota Access, LLC, a non-wholly owned subsidiary of Energy Transfer and/or Dakota Access Pipeline
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, Series H Preferred Units and Series I 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
IFERC	Inside FERC's Gas Market Report
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 Fourth 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	Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series B Preferred Units	Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series C Preferred Units	Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series D Preferred Units	Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series E Preferred Units	Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series F Preferred Units	Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series G Preferred Units	Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series H Preferred Units	Series H Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series I Preferred Units	Series I Fixed-Rate 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)

	March 31, 2024	December 31, 2023
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,946	$ 161
Accounts receivable, net	9,643	9,047
Accounts receivable from related companies	119	101
Inventories	2,267	2,478
Income taxes receivable	58	67
Derivative assets	27	66
Other current assets	447	513
Assets held for sale	511	—
Total current assets	15,018	12,433
Property, plant and equipment	115,631	114,932
Accumulated depreciation and depletion	(30,459)	(29,581)
Property, plant and equipment, net	85,172	85,351
Investments in unconsolidated affiliates	3,093	3,097
Lease right-of-use assets, net	734	826
Other non-current assets, net	1,774	1,733
Intangible assets, net	6,111	6,239
Goodwill	3,887	4,019
Total assets	$ 115,789	$ 113,698

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)

	March 31, 2024	December 31, 2023
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 7,535	$ 6,663
Accounts payable to related companies	29	21
Derivative liabilities	18	8
Operating lease current liabilities	55	56
Accrued and other current liabilities	3,771	3,521
Current maturities of long-term debt	1,181	1,008
Liabilities associated with held for sale	130	—
Total current liabilities	12,719	11,277
Long-term debt, less current maturities	52,295	51,380
Non-current derivative liabilities	—	4
Non-current operating lease liabilities	696	778
Deferred income taxes	4,009	3,931
Other non-current liabilities	1,604	1,611
Commitments and contingencies		
Redeemable noncontrolling interests	673	778
Equity:		
Limited Partners:		
Preferred Unitholders	5,626	6,459
Common Unitholders	30,268	30,197
General Partner	(2)	(2)
Accumulated other comprehensive income	41	28
Total partners' capital	35,933	36,682
Noncontrolling interests	7,860	7,257
Total equity	43,793	43,939
Total liabilities and equity	$ 115,789	$ 113,698

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 March 31,	
	2024	2023
REVENUES:		
Refined product sales	$ 5,513	$ 5,454
Crude sales	6,844	5,478
NGL sales	5,251	4,160
Gathering, transportation and other fees	2,901	2,777
Natural gas sales	855	899
Other	265	227
Total revenues	21,629	18,995
COSTS AND EXPENSES:		
Cost of products sold	16,597	14,610
Operating expenses	1,138	1,025
Depreciation, depletion and amortization	1,254	1,059
Selling, general and administrative	260	238
Impairment losses	—	1
Total costs and expenses	19,249	16,933
OPERATING INCOME	2,380	2,062
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(728)	(619)
Equity in earnings of unconsolidated affiliates	98	88
Loss on extinguishment of debt	(5)	—
Gains (losses) on interest rate derivatives	9	(20)
Other, net	27	7
INCOME BEFORE INCOME TAX EXPENSE	1,781	1,518
Income tax expense	89	71
NET INCOME	1,692	1,447
Less: Net income attributable to noncontrolling interests	436	321
Less: Net income attributable to redeemable noncontrolling interests	16	13
NET INCOME ATTRIBUTABLE TO PARTNERS	1,240	1,113
General Partner’s interest in net income	1	1
Preferred Unitholders’ interest in net income	129	109
Loss on redemption of Series C and Series D Preferred Units	21	—
Common Unitholders’ interest in net income	$ 1,089	$ 1,003
NET INCOME PER COMMON UNIT:		
Basic	$ 0.32	$ 0.32
Diluted	$ 0.32	$ 0.32

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 March 31, 2024	Three Months Ended March 31, 2023
Net income	$ 1,692	$ 1,447
Other comprehensive income (loss), net of tax:		
Change in value of available-for-sale securities	2	1
Actuarial gain (loss) related to pension and other postretirement benefit plans	9	(5)
Foreign currency translation adjustments	—	1
Change in other comprehensive income from unconsolidated affiliates	2	—
	13	(3)
Comprehensive income	1,705	1,444
Less: Comprehensive income attributable to noncontrolling interests	436	321
Less: Comprehensive income attributable to redeemable noncontrolling interests	16	13
Comprehensive income attributable to partners	$ 1,253	$ 1,110

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, 2023	$ 30,197	$ 6,459	$ (2)	$ 28	$ 7,257	$ 43,939
Distributions to partners	(1,039)	(88)	(1)	—	—	(1,128)
Distributions to noncontrolling interests	—	—	—	—	(421)	(421)
Capital contributions from noncontrolling interests	—	—	—	—	637	637
Other comprehensive income, net of tax	—	—	—	13	—	13
Redemption of Series C and Series D Preferred Units	—	(895)	—	—	—	(895)
Other, net	—	21	—	—	(49)	(28)
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,110	129	1	—	436	1,676
Balance, March 31, 2024	$ 30,268	$ 5,626	$ (2)	$ 41	$ 7,860	$ 43,793

	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

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)

	Three Months Ended March 31,	
	2024	2023
OPERATING ACTIVITIES:		
Net income	$ 1,692	$ 1,447
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,254	1,059
Deferred income taxes	67	53
Inventory valuation adjustments	(130)	(29)
Non-cash compensation expense	46	37
Impairment losses	—	1
Loss on extinguishment of debt	5	—
Distributions on unvested awards	(14)	(20)
Equity in earnings of unconsolidated affiliates	(98)	(88)
Distributions from unconsolidated affiliates	84	87
Other non-cash	(7)	2
Net change in operating assets and liabilities, net of effects of acquisitions and divestitures	873	801
Net cash provided by operating activities	3,772	3,350
INVESTING ACTIVITIES:		
Cash paid by Sunoco LP for Zenith Energy terminals acquisition, net of cash received	(185)	—
Cash paid for Edwards Lime Gathering, LLC noncontrolling interest	(84)	—
Cash paid for other acquisitions, net of cash received	(180)	—
Capital expenditures, excluding allowance for equity funds used during construction	(795)	(853)
Contributions in aid of construction costs	25	16
Contributions to unconsolidated affiliates	(2)	—
Distributions from unconsolidated affiliates in excess of cumulative earnings	23	30
Proceeds from sales of other assets	2	4
Net cash used in investing activities	(1,196)	(803)
FINANCING ACTIVITIES:		
Proceeds from borrowings	8,141	7,582
Repayments of debt	(6,257)	(8,605)
USAC investments in government securities in connection with the legal defeasance of senior notes	(749)	—
Redemption of Series C and Series D Preferred Units	(895)	—
Redemption of Crestwood Niobrara LLC preferred units	(37)	—
Capital contributions from noncontrolling interests	637	3
Distributions to partners	(1,128)	(1,001)
Distributions to noncontrolling interests	(421)	(441)
Distributions to redeemable noncontrolling interests	(22)	(12)
Debt issuance costs	(60)	—
Net cash used in financing activities	(791)	(2,474)
Increase in cash and cash equivalents	1,785	73
Cash and cash equivalents, beginning of period	161	257
Cash and cash equivalents, end of period	$ 1,946	$ 330

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, 2023, filed with the SEC on February 16, 2024. 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 AND DIVESTITURES

Sunoco LP’s Acquisitions

On May 3, 2024, Sunoco LP completed the previously announced acquisition of all of the common units of NuStar Energy L.P. (“NuStar”). Under the terms of the merger agreement, NuStar common unitholders received 0.400 Sunoco LP common units for each NuStar common unit. In connection with the acquisition, Sunoco LP issued approximately 50.6 million common units, which had a fair value of approximately $2.8 billion, assumed debt totaling approximately $3.4 billion and assumed preferred units with a fair value of approximately $800 million. NuStar has approximately 9,500 miles of pipeline and 63 terminal and storage facilities that store and distribute crude oil, refined products, renewable fuels, ammonia and specialty liquids. Beginning May 2024, our consolidated financial statements will reflect NuStar as a consolidated subsidiary. At the time our consolidated financial statements were issued, the initial accounting for this business combination was incomplete due to the timing of the close of the acquisition; therefore, certain required disclosures have not been included herein.

On March 13, 2024, Sunoco LP completed the previously announced acquisition of liquid fuels terminals in Amsterdam, Netherlands and Bantry Bay, Ireland from Zenith Energy for approximately €170 million ($185 million), which was allocated $6 million to other current assets, $204 million to property, plant and equipment, $36 million to other non-current assets and $7 million to goodwill. In connection with this transaction, Sunoco LP also assumed $14 million in current liabilities, $11 million in deferred income taxes and $43 million in other non-current liabilities.

Sunoco LP's Divestiture

On April 16, 2024, Sunoco LP completed the previously announced sale of 204 convenience stores located in West Texas, New Mexico and Oklahoma to 7-Eleven, Inc. for approximately $1.00 billion, including customary adjustments for fuel and merchandise inventory. As part of the sale, Sunoco LP also amended its existing take-or-pay fuel supply agreement with 7-Eleven, Inc. to incorporate additional fuel gross profit.

The following table presents the aggregate carrying amount of assets and liabilities that were classified as held for sale:

	March 31, 2024
Carrying amount of assets held for sale:	
Accounts receivable, net	$ 18
Inventories	14
Other current assets	3
Property, plant and equipment, net	171
Goodwill	145
Intangibles	12
Other non-current assets	148
Total assets held for sale	$ 511
Carrying amount of liabilities held for sale:	
Current liabilities	$ 14
Other non-current liabilities	116
Total liabilities associated with assets held for sale	$ 130

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 March 31, 2024 or December 31, 2023.

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

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

	Three Months Ended March 31,	
	2024	2023
Accounts receivable	$ (614)	$ 197
Accounts receivable from related companies	(246)	(3)
Inventories	311	429
Other current assets	79	188
Other non-current assets, net	(76)	(4)
Accounts payable	883	(18)
Accounts payable to related companies	251	(11)
Accrued and other current liabilities	274	(13)
Other non-current liabilities	(34)	31
Derivative assets and liabilities, net	45	5
Net change in operating assets and liabilities, net of effects of acquisitions and divestitures	$ 873	$ 801

Non-cash investing and financing activities were as follows:

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Accrued capital expenditures	$ 421	$ 436
Lease assets obtained in exchange for new lease liabilities	30	1
Distribution reinvestment	22	23
USAC government securities transferred in connection with the legal defeasance of USAC senior notes due 2026	749	—
Legal defeasance of USAC senior notes due 2026	725	—

4. INVENTORIES

Inventories consisted of the following:

	March 31, 2024	December 31, 2023
Natural gas, NGLs and refined products	$ 1,502	$ 1,658
Crude oil	196	258
Spare parts and other	569	562
Total inventories	$ 2,267	$ 2,478

Sunoco LP's fuel inventories are stated at the lower of cost or market using the last-in, first-out ("LIFO") method. As of March 31, 2024 and December 31, 2023, the carrying value of Sunoco LP's fuel inventory included lower of cost or market reserves of $100 million and $230 million, respectively. For the three months ended March 31, 2024 and 2023, 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 March 31, 2024 and 2023, the Partnership's cost of products sold included favorable inventory valuation adjustments of $130 million and $29 million, respectively, related to Sunoco LP's LIFO inventory, which increased net income.

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 three months ended March 31, 2024, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the gross fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of March 31, 2024 and December 31, 2023 based on inputs used to derive their fair values:

		Fair Value Measurements at March 31, 2024	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$ 8	$ —	$ 8
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	2	2	—
Swing Swaps IFERC	2	2	—
Fixed Swaps/Futures	27	27	—
Forward Physical Contracts	9	—	9
Power:			
Forwards	69	69	—
Futures	15	15	—
NGLs – Forwards/Swaps	466	466	—
Refined Products – Futures	3	3	—
Crude – Forwards/Swaps	50	50	—
Total commodity derivatives	643	634	9
Other non-current assets	32	21	11
Total assets	$ 683	$ 655	$ 28
Liabilities:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ (8)	$ (8)	$ —
Swing Swaps IFERC	(2)	(2)	—
Fixed Swaps/Futures	(13)	(13)	—
Power:			
Forwards	(68)	(68)	—
Futures	(12)	(12)	—
NGLs – Forwards/Swaps	(448)	(448)	—
Refined Products – Futures	(19)	(19)	—
Crude – Forwards/Swaps	(60)	(60)	—
Total commodity derivatives	(630)	(630)	—
Total liabilities	$ (630)	$ (630)	$ —

		Fair Value Measurements at December 31, 2023	
	Fair Value Total	Level 1	Level 2
Assets:			
Interest rate derivatives	$ 6	$ —	$ 6
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	24	24	—
Swing Swaps IFERC	20	20	—
Fixed Swaps/Futures	77	77	—
Forward Physical Contracts	8	—	8
Power:			
Forwards	57	57	—
Futures	8	8	—
NGLs – Forwards/Swaps	336	336	—
Refined Products – Futures	35	35	—
Crude – Forwards/Swaps	45	45	—
Total commodity derivatives	610	602	8
Other non-current assets	31	20	11
Total assets	$ 647	$ 622	$ 25
Liabilities:			
Interest rate derivatives	$ (4)	$ —	$ (4)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(3)	(3)	—
Swing Swaps IFERC	(2)	(2)	—
Fixed Swaps/Futures	(16)	(16)	—
Options – Puts	(2)	(2)	—
Power:			
Forwards	(56)	(56)	—
Futures	(8)	(8)	—
NGL/Refined Products Option - Puts	(1)	(1)	—
NGL/Refined Products Option - Calls	(1)	(1)	—
NGLs – Forwards/Swaps	(316)	(316)	—
Refined Products – Futures	(18)	(18)	—
Crude – Forwards/Swaps	(37)	(37)	—
Total commodity derivatives	(460)	(460)	—
Total liabilities	$ (464)	$ (460)	$ (4)

The aggregate estimated fair value and carrying amount of our consolidated debt obligations as of March 31, 2024 were $52.85 billion and $53.48 billion, respectively. As of December 31, 2023, the aggregate fair value and carrying amount of our consolidated debt obligations were $51.93 billion and $52.39 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 March 31,	
	2024	2023
Net income	$ 1,692	$ 1,447
Less: Net income attributable to noncontrolling interests	436	321
Less: Net income attributable to redeemable noncontrolling interests	16	13
Net income, net of noncontrolling interests	1,240	1,113
Less: General Partner's interest in net income	1	1
Less: Preferred Unitholders' interest in net income	129	109
Less: Loss on redemption of Series C and Series D Preferred Units	21	—
Common Unitholders' interest in net income	$ 1,089	$ 1,003
Basic Income per Common Unit:		
Weighted average common units	3,368.6	3,095.5
Basic income per common unit	$ 0.32	$ 0.32
Diluted Income per Common Unit:		
Common Unitholders' interest in net income	$ 1,089	$ 1,003
Dilutive effect of equity-based compensation of subsidiaries [(1)]	1	—
Diluted income attributable to Common Unitholders	$ 1,088	$ 1,003
Weighted average common units	3,368.6	3,095.5
Dilutive effect of unvested restricted unit awards [(1)]	21.5	19.9
Weighted average common units, assuming dilutive effect of unvested restricted unit awards	3,390.1	3,115.4
Diluted income per common unit	$ 0.32	$ 0.32

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

7. DEBT OBLIGATIONS

Recent Transactions

Energy Transfer Senior Notes Redemptions

During the first quarter of 2024, the Partnership redeemed its $1.15 billion aggregate principal amount of 5.875% Senior Notes due January 2024, $350 million aggregate principal amount of 4.90% Senior Notes due February 2024 and $82 million aggregate principal amount of 7.60% Senior Notes due February 2024 using proceeds from its January 2024 notes issuance described below.

In April 2024, the Partnership redeemed its $500 million aggregate principal amount of 4.25% Senior Notes due April 2024, $750 million aggregate principal amount of 4.50% Senior Notes due April 2024 and $450 million aggregate principal amount of 8.00% Senior Notes due April 2029 using cash on hand and proceeds from its Five-Year Credit Facility (defined below).

Bakken Project Debt Redemption

In April 2024, the Bakken Pipeline entities redeemed $1.00 billion aggregate principal amount of 3.90% Senior Notes due April 2024 using proceeds from member contributions. The Partnership indirectly owns 36.4% of the ownership interests in the Bakken Pipeline entities.

Energy Transfer January 2024 Notes Issuance

In January 2024, the Partnership issued $1.25 billion aggregate principal amount of 5.55% Senior Notes due 2034, $1.75 billion aggregate principal amount of 5.95% Senior Notes due 2054 and $800 million aggregate principal amount of

8.00% fixed-to-fixed reset rate Junior Subordinated Notes due 2054. The Partnership used the net proceeds to refinance existing indebtedness, including borrowings under its Five-Year Credit Facility, to redeem its outstanding Series C Preferred Units and Series D Preferred Units and for general partnership purposes. The Partnership will also use the net proceeds to redeem its outstanding Series E Preferred Units in May 2024.

Sunoco LP April 2024 Notes Issuance

On April 30, 2024, Sunoco LP issued $750 million of 7.000% senior notes due 2029 and $750 million of 7.250% senior notes due 2032 in a private offering. Sunoco LP used the net proceeds from the offering to (i) repay certain outstanding indebtedness of NuStar, in connection with the merger between Sunoco LP and NuStar, (ii) fund the redemption of NuStar's preferred units in connection with the merger and (iii) pay offering fees and expenses.

USAC March 2024 Notes Issuance

In March 2024, USAC issued $1.00 billion aggregate principal amount of 7.125% Senior Notes due 2029. The net proceeds from this issuance were used to repay a portion of existing borrowings under USAC's revolving credit facility, to redeem its $725 million aggregate principal amount of 6.875% senior notes due 2026, which constituted a legal defeasance under GAAP (the "Defeasance"), and for general partnership purposes.

The Defeasance required a cash outlay in the net amount of $749 million, which was used to purchase U.S. government securities. These securities generated sufficient cash upon maturity to fund interest payments on the senior notes due 2026 occurring between the effective date of the Defeasance through April 4, 2024, when the senior notes due 2026 were redeemed at par, as well as fund the redemption of the senior notes due 2026 in full. As a result of the Defeasance, USAC recognized a loss on early extinguishment of debt of $5 million for the three months ended March 31, 2024.

Current Maturities of Long-Term Debt

As of March 31, 2024, 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 were repaid in April 2024 as discussed above under "Recent Transactions." Current maturities of long-term debt also reflected $175 million aggregate principal amount of Transwestern's 5.66% senior notes due December 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 March 31, 2024, the Five-Year Credit Facility had no outstanding borrowings and no outstanding commercial paper. The amount available for future borrowings was $4.97 billion, after accounting for outstanding letters of credit in the amount of $29 million.

Sunoco LP Credit Facility

As of March 31, 2024, Sunoco LP's credit facility had $625 million of outstanding borrowings and $5 million in standby letters of credit and matures in May 2029 (as amended in May 2024). The amount available for future borrowings at March 31, 2024 was $870 million. The weighted average interest rate on the total amount outstanding as of March 31, 2024 was 7.18%.

USAC Credit Facility

As of March 31, 2024, USAC's credit facility, which matures in December 2026, had $736 million of outstanding borrowings and $1 million outstanding letters of credit. As of March 31, 2024, USAC's credit facility had $863 million of remaining unused availability of which, due to restrictions related to compliance with the applicable financial covenants, $429 million was available to be drawn. The weighted average interest rate on the total amount outstanding as of March 31, 2024 was 8.00%.

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 March 31, 2024. For the quarter ended March 31, 2024, our leverage ratio, as calculated pursuant to the covenant related to our Five-Year Credit Facility, was 3.27x.

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 March 31, 2024 and December 31, 2023 included a balance of $431 million and $476 million, respectively, related to the USAC Series A preferred units; $220 million and $280 million, respectively, related to Crestwood Niobrara LLC preferred units; and $22 million related to noncontrolling interest holders in one of the Partnership's consolidated subsidiaries that have the option to sell their interests to the Partnership.

USAC Preferred Unit Conversions

On January 12, 2024, the holders of USAC preferred units elected to convert 40,000 preferred units into 1,998,850 common units. These preferred units were converted into common units and, for USAC's fourth-quarter 2023 distribution, the holders received the common unit distribution of $0.525 on the 1,998,850 common units in lieu of the preferred unit distribution of $24.375 on the converted 40,000 preferred units.

On April 1, 2024, the holders of USAC preferred units elected to convert 280,000 preferred units into 13,991,954 common units. These preferred units were converted into common units and, for USAC's first-quarter 2024 distribution, the holders received the common unit distribution of $0.525 on the 13,991,954 common units in lieu of the preferred unit distribution of $24.375 on the converted 280,000 preferred units.

Niobrara Preferred Unit Redemption

On February 23, 2024, the Partnership paid approximately $37 million in cash to redeem a portion of the outstanding Crestwood Niobrara LLC preferred units.

9. EQUITY

Energy Transfer Common Units

Changes in Energy Transfer common units during the three months ended March 31, 2024 were as follows:

	Number of Units
Number of common units at December 31, 2023	3,367.5
Common units issued under the distribution reinvestment plan	1.6
Common units vested under equity incentive plans and other	0.8
Number of common units at March 31, 2024	3,369.9

Energy Transfer Repurchase Program

During the three months ended March 31, 2024, Energy Transfer did not repurchase any of its common units under its current buyback program. As of March 31, 2024, $880 million remained available to repurchase under the current program.

Energy Transfer Distribution Reinvestment Program

During the three months ended March 31, 2024, distributions of $22 million were reinvested under the distribution reinvestment program. As of March 31, 2024, a total of 43 million Energy Transfer common units remained available to be issued under currently effective registration statements 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, 2023 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2023	February 7, 2024	February 20, 2024	$ 0.3150
March 31, 2024	May 13, 2024	May 20, 2024	0.3175

Energy Transfer Preferred Units

As of March 31, 2024, Energy Transfer's outstanding preferred units included 950,000 Series A Preferred Units, 550,000 Series B Preferred Units, 32,000,000 Series E Preferred Units, 500,000 Series F Preferred Units, 1,484,780 Series G Preferred Units, 900,000 Series H Preferred Units and 41,464,179 Series I Preferred Units. In addition, as of December 31, 2023, Energy Transfer's outstanding preferred units also included 18,000,000 Series C Preferred Units and 17,800,000 Series D Preferred Units, both of which were redeemed in February 2024. In March 2024, the Partnership issued a notice to redeem all of its outstanding Series E Preferred Units on May 15, 2024.

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	Series I	Total
Balance, December 31, 2023	$ 948	$ 556	$ 438	$ 435	$ 786	$ 496	$ 1,488	$ 893	$ 419	$ 6,459
Distributions to partners	(24)	(18)	(11)	(11)	(15)	—	—	—	(9)	(88)
Redemption of preferred units	—	—	(450)	(445)	—	—	—	—	—	(895)
Other, net	—	—	11	10	—	—	—	—	—	21
Net income	23	9	12	11	15	8	27	15	9	129
Balance, March 31, 2024	$ 947	$ 547	$ —	$ —	$ 786	$ 504	$ 1,515	$ 908	$ 419	$ 5,626

	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

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	Series B [(1)]	Series C	Series D	Series E	Series F [(1)]	Series G [(1)]	Series H [(1)]	Series I
December 31, 2023	February 1, 2024	February 15, 2024	$ 24.710	$ 33.125	$ 0.6075	$ 0.6199	$ 0.475	$ —	$ —	$ —	$ 0.2111
March 31, 2024	May 1, 2024	May 15, 2024	23.992	—	—	—	0.475	33.750	35.630	32.500	0.2111

(1) Series B, Series F, Series G and Series H distributions are currently paid on a semi-annual basis. Pursuant to its terms, distributions on the Series B Preferred Units will begin to be paid quarterly on February 15, 2028.

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[(1)]	May 15, 2024	5.161 %	0.26161 %	Three-month SOFR

(1) The Partnership will redeem all of its outstanding Series E Preferred Units on May 15, 2024.

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, 2023 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2023	February 7, 2024	February 20, 2024	$ 0.8420
March 31, 2024	May 13, 2024	May 20, 2024	0.8756

USAC Cash Distributions

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2023 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2023	January 22, 2024	February 2, 2024	$ 0.525
March 31, 2024	April 22, 2024	May 3, 2024	0.525

Accumulated Other Comprehensive Income

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

	March 31, 2024	December 31, 2023
Available-for-sale securities	$ 15	$ 13
Foreign currency translation adjustment	(5)	(5)
Actuarial gains related to pensions and other postretirement benefits	15	6
Investments in unconsolidated affiliates, net	16	14
Total AOCI included in partners' capital, net of tax	$ 41	$ 28

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 (the "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 Federal District Court ordered that the Federal 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. On November 13, 2023, the FERC appealed the Federal District Court order to the United States Court of Appeals for the Fifth Circuit. On December 11, 2023, FERC filed a motion to withdraw that appeal, which the Fifth Circuit granted on December 12, 2023. The FERC and the Federal District Court proceedings remain stayed pending resolution of the case pending before the United States Supreme Court. A decision on that Supreme Court case is expected by June 2024. 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. FERC has taken no further action on the case since that time.

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 on 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 the FERC further considered the requests for rehearing of its December 16, 2022 order. On September 25, 2023, the FERC issued its order addressing arguments raised on rehearing and compliance, which denied our requests for rehearing. Panhandle has timely filed its Petition for Review with the Court of Appeals regarding the September 25, 2023 order. On October 25, 2023, Panhandle filed a limited request for rehearing of the September 25 order addressing arguments raised on rehearing and compliance, which was subsequently denied by operation of law on November 27, 2023. On November 30, 2023, Panhandle submitted a refund report regarding the consolidated rate proceedings, which has been protested by several parties. On January 5, 2024, the FERC issued a second order addressing arguments raised on rehearing in which it modified certain discussion from its September 25, 2023 order and sustained its prior conclusions. Panhandle has timely filed its Petition for Review with the Court of Appeals regarding the January 5, 2024 order.

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. On November 29, 2023, the parties reached a settlement in principle. The settlement was filed with the FERC on December 29, 2023 and approved by letter order on February 21, 2024. Among other things, the settlement requires Sea Robin to submit a refund report by May 21, 2024 detailing the amount of refunds, if any, due to Sea Robin's shippers as a result of the proceeding. Moreover, the settlement established a rate case moratorium prohibiting Sea Robin or any party to the proceeding from seeking or soliciting a change or challenge to Sea Robin's rates prior to December 1, 2026.

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. The audit team is in the process of implementing recommendations made by FERC, none of which would have a material impact on the Partnership's financial position or results of operations.

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 March 31,	
	2024	2023
ROW expense	$ 13	$ 13

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 March 31, 2024 and December 31, 2023, accruals of approximately $254 million and $285 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. Comments on the Draft EIS were due on December 13, 2023. 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.

Louisiana Dispute with New Generation Gas Gathering LLC

On August 31, 2023, Energy Partners, LP and ETC Texas Pipeline, LTD amended the next day to be ETC Texas Pipeline, Ltd, Gulf Run Transmission LLC, Enable Midstream Partners LP and ETC Tiger Pipeline LLC (collectively "Energy Transfer"), filed a petition for declaratory judgment against New Generation Gas Gathering LLC ("NG3") in the 42nd Judicial District Court of DeSoto Parish, Louisiana. In relation to seven specific servitudes in DeSoto Parish, Louisiana underlying Energy Transfer natural gas pipelines, Energy Transfer requested declarations from the Court that, pursuant to Louisiana Civil Code Article 720, NG3 must obtain Energy Transfer's permission to install NG3's proposed pipelines across the Energy Transfer servitudes so that Energy Transfer may determine if NG3's proposed installation of its proposed pipelines would interfere with Energy Transfer's use of its existing servitudes.

On November 13, 2023, NG3 filed its answer and reconventional demand (a Louisiana term for counterclaim) asserting six claims against the entities asserting the claim, as well as against Energy Transfer LP. In Count I, NG3 seeks declaratory judgment that Energy Transfer lacks the right to object to its proposed crossings of Energy Transfer's natural gas pipelines that adversely affect Energy Transfer. In Counts II–VI, NG3 asserts five causes of action alleging that Energy Transfer's objection and lawsuit seeking court determination that it has the right to object to NG3's request to cross Energy Transfer's pipelines more than one hundred times constitutes tortious conduct, an abuse of Energy Transfer's rights, an unfair trade practice, and a violation of Louisiana Monopolies Act sections prohibiting conspiracies, monopolies and attempted monopolies.

On December 7, 2023, the trial court set the deadline for Energy Transfer to respond to NG3's reconventional demand as February 9, 2024, set a hearing on any exceptions for March 25, 2024, and set a trial date for September 9, 2024. The parties have begun written discovery.

On February 7, 2024, the Attorney General for the State of Louisiana, Public Protection Division (the "AG") gave notice of a complaint filed by NG3. NG3 asserts that Energy Transfer violated Louisiana Revised Statutes 51:1401, et seq., the Unfair Trade Practices and Consumer Protection Law. The AG has not investigated this matter and it makes no determination as to the merits of matter.

On March 25, 2024, the trial court denied Energy Transfer's motion to strike NG3's Counts II-VI, Energy Transfer's exceptions, and NG3's exceptions. Energy Transfer has filed an appeal of the trial court's orders denying its exceptions and motion to strike.

Energy Transfer cannot predict the ultimate outcome of this litigation but will vigorously defend against these claims.

Litigation Regarding Louisiana Energy Gateway LLC

Louisiana Energy Gateway LLC v. ETC Tiger Pipeline, LLC, 42nd Judicial District Court, DeSoto Parish Docket No. 84202; and *ETC Tiger Pipeline, LLC v. Louisiana Energy Gateway LLC*, 42nd Judicial District Court, DeSoto Parish Docket No. 84242 ("NORWELA"); and *Louisiana Energy Gateway LLC v. ETC Tiger Pipeline, LLC*, 1st Judicial District

Court, Caddo Parish Docket No. 644810; and *ETC Tiger Pipeline, LLC v. Louisiana Energy Gateway LLC*, 1st Judicial District Court, Caddo Parish Docket No. 645193 ("LEMAC").

The NORWELA and LEMAC disputes concern Louisiana Energy Gateway LLC's ("LEG") requests to construct pipelines across and under "exclusive" servitudes in Caddo and DeSoto parishes owned by ETC Tiger Pipeline, LLC ("Tiger"), within which Tiger operates and maintains the ETC Tiger Pipeline, a 42-inch FERC regulated transmission line. LEG instituted each of the disputes by filing petitions for declaratory judgment suits seeking a declaration of Tiger and LEG's competing servitude rights on June 30, 2023, in the First Judicial District Court in Caddo Parish, and the 42nd Judicial District Court in DeSoto Parish, respectively. The original declaratory judgment suits have not been actively litigated since their filing.

LEG then took steps to begin construction of the same two requested crossings and communicated its intent to immediately begin construction of its pipeline crossings at the NORWELA and LEMAC tracts, forcing Tiger to file companion lawsuits seeking temporary restraining orders, preliminary injunctions and permanent injunctions in Caddo and DeSoto parishes on July 24, 2023. Hearings on Tiger's requests for preliminary injunction were heard on August 15, 2023 in DeSoto Parish in the NORWELA matter, and on August 17, 2023 in Caddo Parish in the LEMAC matter. Judgments entering preliminary injunction, prohibiting LEG's construction pending ultimate resolution of the cases on the merits, were entered on November 8, 2023 in LEMAC and on December 18, 2023 in NORWELA. LEG timely perfected appeals of the judgments entering both preliminary injunctions. The Louisiana Second Circuit Court of Appeal will hear the appeals, which have not yet been lodged.

Trial on the merits has not been set in either LEMAC or NORWELA. Tiger cannot predict the ultimate outcome of this litigation but intends to vigorously prosecute its claim for .mandatory injunctions.

In related litigation at FERC, on April 8, 2024, Energy Transfer filed a petition for order to show cause regarding whether The Williams Companies, Inc. are constructing LEG without first seeking Commission approval under Section 7 of the Natural Gas Act. FERC issued a notice of petition for order to show cause on April 11, 2024, which established a comment deadline of May 13, 2024.

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 March 31, 2024, 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.

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.

On November 17, 2023, the State of Ohio appealed the trial judge's decision to Ohio's Fifth District Court of Appeals. The State filed its initial brief on January 8, 2024. Energy Transfer and Rover filed a responsive brief on February 20, 2024. The State filed a reply brief on February 26, 2024. Oral argument on the appeal is anticipated but is not currently scheduled. Energy Transfer and Rover intend to vigorously defend this claim.

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 al., 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 S. 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. 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 January 19, 2024, the defendants filed a motion for summary judgment on all of the claims asserted in ACERS' amended complaint, and ACERS filed a motion for partial summary judgment.

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 represented at the time 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 was sent back to the trial court so that the district court could 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 ETMT'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. ETMT intends on appealing the entirety of the judgment and filed its Opening Brief on the Merits to the Tenth Circuit on March 14, 2024.

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. Defendants have filed a motion seeking permission from the appellate court to allow an interlocutory appeal of the order denying their Traditional Motion for Partial Summary Judgment Regarding Fraud. That motion remains pending before the appellate court.

Discovery has closed in this matter. Trial on Plaintiff Energy Transfer LP's fraud claim 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%) 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, which the Company has completed as of January 17, 2024.

Crestwood Midstream Partners, LP – Linde Litigation

On December 23, 2019, Linde Engineering North America Inc. ("Linde") filed a lawsuit in the District Court of Harris County, Texas alleging that Arrow Field Services, LLC, our consolidated subsidiary, and Crestwood Midstream Partners, LP (collectively, "Crestwood") breached a contract entered into in March 2018 under which Linde was to provide engineering, procurement and construction services to Crestwood related to the completion of the construction of the Bear Den II cryogenic processing plant.

Trial was held in June 2022, and a final judgment was entered on October 24, 2022. The final judgment includes an award of damages of approximately $20.7 million, a pre-judgment interest award of approximately $17.7 million and attorney fees and other costs of approximately $4.7 million. Crestwood has insurance coverage related to certain pre-judgment interest awards but has not recorded a receivable related to any potential insurance recovery on June 30, 2023. On January 9, 2023, Crestwood paid approximately $21.2 million to the Court Registry under protest to mitigate the impact of post-judgment interest. Crestwood filed a Notice of Appeal on January 13, 2023, and filed its Appellate Brief on September 29, 2023. Linde's response was filed on February 8, 2024. Crestwood anticipates that oral argument will be held in late 2024. Crestwood is unable to predict the ultimate outcome on the appeal related to this matter.

State of Oklahoma Attorney General – Winter Storm Uri

On April 10, 2024, the State of Oklahoma, through Attorney General Gentner Drummond, ("Plaintiff") filed a Petition on behalf of Grand River Dam Authority ("GRDA") against Defendants ET Gathering & Processing, LLC, successor by merger to Enable Midstream Partners, LP, Enable Oklahoma Intrastate Transmission, LLC, Enable Gas Transmission, LLC and Enable Energy Resources, LLC (collectively, "Defendants") arising out of Winter Storm Uri in February 2021. Specifically, Plaintiff alleges that Defendants violated the Oklahoma Antitrust Reform Act (79 O.S. §201, *et. seq.*) by acting individually and in concert with each other to unreasonably restrain trade in the natural gas market in Oklahoma during the storm. Plaintiff also alleges causes of action for breach of contract, unjust enrichment, fraud, bad faith, conspiracy and negligence. Plaintiff's Petition seeks actual damages, punitive damages, treble damages and attorney's fees and costs. However, the actual amount sought was not specified. Defendants cannot predict the ultimate outcome of this litigation but will vigorously defend against these claims.

Tax Contingencies

Internal Revenue Service Audits

The Partnership's 2020 U.S. Federal income tax return is currently under examination by the Internal Revenue Service ("IRS"). The IRS is also auditing Crestwood's 2020 U.S. Federal income tax return. In general, Energy Transfer and its subsidiaries are no longer subject to examination by the IRS, and most state tax authorities, for the 2018 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 $27 million, including interest. 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, as applicable, with respect to an audited and adjusted return.

USAC - Oklahoma Tax Commission

USAC is currently protesting certain assessments made by the Oklahoma Tax Commission ("OTC"). USAC believes it is reasonably possible that it could incur losses related to this assessment. Whether, and to what extent, USAC incurs losses depends on whether the administrative law judge assigned by the OTC accepts or rejects USAC's position that the transactions are not taxable and, if rejected, whether USAC ultimately loses any and all subsequent legal challenges to such determination. USAC estimates that the range of losses it could incur is up to $28 million, including penalties and interest.

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 March 31, 2024, the Partnership had been named as a PRP at approximately 32 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.

	March 31, 2024	December 31, 2023
Current	$ 47	$ 42
Non-current	233	235
Total environmental liabilities	$ 280	$ 277

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 three months ended March 31, 2024 and 2023, the Partnership recorded $3 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, 2023	$ 749
Additions	291
Revenue recognized	(297)
Balance, March 31, 2024	$ 743
Balance, December 31, 2022	$ 615
Additions	278
Revenue recognized	(301)
Balance, March 31, 2023	$ 592

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

	March 31, 2024	December 31, 2023
Contract assets	$ 264	$ 256
Accounts receivable from contracts with customers	794	809
Contract liabilities	—	—

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 March 31, 2024, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations was $38.12 billion. The Partnership expects to recognize this amount as revenue within the time bands illustrated in the following table:

	Years Ending December 31,				
	2024 (remainder)	2025	2026	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of March 31, 2024	$ 5,754	$ 6,726	$ 5,960	$ 19,677	$ 38,117

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:

	March 31, 2024		December 31, 2023	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	5,653	2024-2025	(1,878)	2024-2025
Basis Swaps IFERC/NYMEX [(1)]	(36,158)	2024-2025	(171,185)	2024
Swing Swaps	—	2024	(900)	2024
Options – Puts	—	2024	1,900	2024
Options – Calls	250	2024	250	2024
Power (Megawatt):				
Forwards	220,220	2024-2029	155,600	2024-2029
Futures	(974,635)	2024-2026	(464,897)	2024
Options – Puts	32,000	2024-2025	136,000	2024
Crude (MBbls):				
Options – Puts	—	2024	(15)	2024
Options – Calls	—	2024	(20)	2024
NGL/Refined Products (MBbls):				
Options – Puts	33	2024-2026	121	2024-2026
Options – Calls	34	2024-2026	(43)	2024-2026
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	71,395	2024-2025	124,210	2024-2025
Swing Swaps IFERC	(104,643)	2024-2025	(96,828)	2024-2025
Fixed Swaps/Futures	10,865	2024-2026	7,125	2024-2026
Forward Physical Contracts	5,790	2024-2026	(1,751)	2024-2026
NGLs (MBbls) – Forwards/Swaps	(3,113)	2024-2027	(13,870)	2024-2027
Crude (MBbls) – Forwards/Swaps	(1,780)	2024-2025	(2,674)	2024-2025
Refined Products (MBbls) – Futures	(2,760)	2024-2026	(4,548)	2024-2025
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(49,858)	2024-2025	(39,013)	2024
Fixed Swaps/Futures	(49,858)	2024-2025	(39,013)	2024
Hedged Item – Inventory	49,858	2024-2025	39,013	2024

(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 USAC’s interest rate swap outstanding which was not designated as a hedge for accounting purposes:

		Notional Amount Outstanding	
Term	Type	March 31, 2024	December 31, 2023
December 2025	Pay a fixed rate of 3.9725% and receive a floating rate based on SOFR	$ 700	$ 700

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 in our financial position or results of operations as a consequence of counterparty non-performance.

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

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

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	March 31, 2024	December 31, 2023	March 31, 2024	December 31, 2023
Derivatives designated as hedging instruments:				
Commodity derivatives – margin deposits	$ 51	$ 51	$ (32)	$ (6)
	51	51	(32)	(6)
Derivatives not designated as hedging instruments:				
Commodity derivatives – margin deposits	500	427	(507)	(374)
Commodity derivatives	92	132	(91)	(80)
Interest rate derivatives	8	6	—	(4)
	600	565	(598)	(458)
Total derivatives	$ 651	$ 616	$ (630)	$ (464)

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

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	March 31, 2024	December 31, 2023	March 31, 2024	December 31, 2023
Derivatives without offsetting agreements	Derivative assets (liabilities)	$ 8	$ 6	$ —	$ (4)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	92	132	(91)	(80)
Broker cleared derivative contracts	Other current assets (liabilities)	551	478	(539)	(380)
Total gross derivatives		651	616	(630)	(464)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(73)	(72)	73	72
Counterparty netting	Other current assets (liabilities)	(514)	(368)	514	368
Total net derivatives		$ 64	$ 176	$ (43)	$ (24)

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 March 31,	
		2024	2023
Derivatives not designated as hedging instruments:			
Commodity derivatives – Trading	Cost of products sold	$ (1)	$ (12)
Commodity derivatives – Non-trading	Cost of products sold	17	68
Interest rate derivatives	Gains on interest rate derivatives	9	(20)
Total		$ 25	$ 36

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 valuation 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 March 31,	
	2024	2023
Revenues:		
Intrastate transportation and storage:		
Revenues from external customers	$ 810	$ 814
Intersegment revenues	108	476
	918	1,290
Interstate transportation and storage:		
Revenues from external customers	595	622
Intersegment revenues	7	12
	602	634
Midstream:		
Revenues from external customers	806	809
Intersegment revenues	1,968	1,945
	2,774	2,754
NGL and refined products transportation and services:		
Revenues from external customers	5,684	4,737
Intersegment revenues	842	866
	6,526	5,603
Crude oil transportation and services:		
Revenues from external customers	7,638	6,079
Intersegment revenues	—	1
	7,638	6,080
Investment in Sunoco LP:		
Revenues from external customers	5,495	5,349
Intersegment revenues	4	13
	5,499	5,362
Investment in USAC:		
Revenues from external customers	223	192
Intersegment revenues	6	5
	229	197
All other:		
Revenues from external customers	378	393
Intersegment revenues	88	151
	466	544
Eliminations	(3,023)	(3,469)
Total revenues	$ 21,629	$ 18,995

	Three Months Ended March 31,	
	2024	2023
Segment Adjusted EBITDA:		
Intrastate transportation and storage	$ 438	$ 409
Interstate transportation and storage	483	536
Midstream	696	641
NGL and refined products transportation and services	989	939
Crude oil transportation and services	848	526
Investment in Sunoco LP	242	221
Investment in USAC	139	118
All other	45	43
Adjusted EBITDA (consolidated)	$ 3,880	$ 3,433

	Three Months Ended March 31,	
	2024	2023
Reconciliation of net income to Adjusted EBITDA:		
Net income	$ 1,692	$ 1,447
Depreciation, depletion and amortization	1,254	1,059
Interest expense, net of interest capitalized	728	619
Income tax expense	89	71
Impairment losses	—	1
(Gains) losses on interest rate derivatives	(9)	20
Non-cash compensation expense	46	37
Unrealized losses on commodity risk management activities	141	130
Inventory valuation adjustments (Sunoco LP)	(130)	(29)
Loss on extinguishment of debt	5	—
Adjusted EBITDA related to unconsolidated affiliates	171	161
Equity in earnings of unconsolidated affiliates	(98)	(88)
Other, net	(9)	5
Adjusted EBITDA (consolidated)	$ 3,880	$ 3,433

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, 2023 filed with the SEC on February 16, 2024. 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, 2023 filed with the SEC on February 16, 2024. 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

Sunoco LP's Acquisitions

On May 3, 2024, Sunoco LP completed the previously announced acquisition of all of the common units of NuStar Energy L.P. ("NuStar"). Under the terms of the merger agreement, NuStar common unitholders received 0.400 Sunoco LP common units for each NuStar common unit. In connection with the acquisition, Sunoco LP issued approximately 50.6 million common units, which had a fair value of approximately $2.8 billion, assumed debt totaling approximately $3.4 billion and assumed preferred units with a fair value of approximately $800 million. NuStar has approximately 9,500 miles of pipeline and 63 terminal and storage facilities that store and distribute crude oil, refined products, renewable fuels, ammonia and specialty liquids.

On March 13, 2024, Sunoco LP completed the previously announced acquisition of liquid fuels terminals in Amsterdam, Netherlands and Bantry Bay, Ireland from Zenith Energy for approximately €170 million ($185 million), including working capital.

Sunoco LP's Divestiture

On April 16, 2024, Sunoco LP completed the previously announced sale of 204 convenience stores located in West Texas, New Mexico and Oklahoma to 7-Eleven, Inc. for approximately $1.00 billion, including customary adjustments for fuel and merchandise inventory. As part of the sale, Sunoco LP also amended its existing take-or-pay fuel supply agreement with 7-Eleven, Inc. to incorporate additional fuel gross profit.

Quarterly Cash Distribution

In April 2024, Energy Transfer announced a quarterly distribution of $0.3175 per unit ($1.27 annualized) on Energy Transfer common units for the quarter ended March 31, 2024.

Regulatory Update

Interstate Natural Gas Transportation Regulation

<u>Rate Regulation</u>

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 on 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 the FERC further considered the requests for rehearing of its December 16, 2022 order. On September 25, 2023, the FERC issued its order addressing arguments raised on rehearing and compliance, which denied our requests for rehearing. Panhandle has timely filed its Petition for Review with the Court of Appeals regarding the September 25, 2023 order. On October 25, 2023, Panhandle filed a limited request for rehearing of the September 25 order addressing arguments raised on rehearing and compliance, which was subsequently denied by operation of law on November 27, 2023. On November 30, 2023, Panhandle submitted a refund report regarding the consolidated rate proceedings, which has been protested by several parties. On January 5, 2024, the FERC issued a second order addressing arguments raised on rehearing in which it modified certain discussion from its September 25, 2023 order and sustained its prior conclusions. Panhandle has timely filed its Petition for Review with the Court of Appeals regarding the January 5, 2024 order.

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 five states and pending a decision on a stay in four other states. Additionally, other operators and industry groups have challenged the Plan and sought a stay 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 was heard on February 21, 2024, all while EPA has proposed adding five more states to the Plan. Thereafter, one of the states whose case was recently transferred to the DC Circuit filed a Petition for Writ of Certiorari with the U.S. Supreme Court, requesting that the Court resolve the Circuit split on venue. The Partnership currently estimates that the final rule would require retrofitting or replacement of approximately 192 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.

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 valuation 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 March 31,		
	2024	2023	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 438	$ 409	$ 29
Interstate transportation and storage	483	536	(53)
Midstream	696	641	55
NGL and refined products transportation and services	989	939	50
Crude oil transportation and services	848	526	322
Investment in Sunoco LP	242	221	21
Investment in USAC	139	118	21
All other	45	43	2
Adjusted EBITDA (consolidated)	$ 3,880	$ 3,433	$ 447

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Change
Reconciliation of net income to Adjusted EBITDA:			
Net income	$ 1,692	$ 1,447	$ 245
Depreciation, depletion and amortization	1,254	1,059	195
Interest expense, net of interest capitalized	728	619	109
Income tax expense	89	71	18
Impairment losses	—	1	(1)
(Gains) losses on interest rate derivatives	(9)	20	(29)
Non-cash compensation expense	46	37	9
Unrealized losses on commodity risk management activities	141	130	11
Inventory valuation adjustments (Sunoco LP)	(130)	(29)	(101)
Loss on extinguishment of debt	5	—	5
Adjusted EBITDA related to unconsolidated affiliates	171	161	10
Equity in earnings of unconsolidated affiliates	(98)	(88)	(10)
Other, net	(9)	5	(14)
Adjusted EBITDA (consolidated)	$ 3,880	$ 3,433	$ 447

Net Income. For the three months ended March 31, 2024 compared to the same period last year, net income increased $245 million, or approximately 17%. Operating income increased $318 million, which reflected higher segment margin from our crude oil transportation and services segment, as well as improved results from multiple other segments, as discussed in more detail in "Segment Operating Results." These increases were partially offset by increases in depreciation, depletion and amortization and interest expense.

Adjusted EBITDA (consolidated). For the three months ended March 31, 2024 compared to the same period last year, Adjusted EBITDA increased $447 million. This increase included a $322 million increase from our crude oil transportation and services segment, primarily driven by recently acquired assets and higher volumes. The increase in Adjusted EBITDA also reflected increases from our other segments, partially offset by a decrease in our interstate transportation and storage segment.

Additional discussion on the changes impacting net income and Adjusted EBITDA for the three months ended March 31, 2024 compared to the same period last year is available below and in "Segment Operating Results."

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased for the three months ended March 31, 2024 compared to the same period 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 months ended March 31, 2024 compared to the same period last year primarily due to higher aggregate debt balances as a result of the Crestwood acquisition as well as higher interest rates on floating rate and recently refinanced debt.

Income Tax Expense. For the three months ended March 31, 2024 compared to the same period last year, income tax expense increased due to higher earnings from the Partnership's consolidated corporate subsidiaries.

Impairment Losses. For the three months ended March 31, 2023, impairment losses included a total of $1 million recognized by USAC related to its compression equipment.

Gains (Losses) on Interest Rate Derivatives. Gains and losses on interest rate derivatives resulted from changes in forward interest rates, which caused our forward-starting swaps to change in value.

Unrealized 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 March 31, 2024 and March 31, 2023, increases in fuel prices caused the lower of cost or market reserve requirements to decrease by $130 million and $29 million, respectively, which increased net income.

Loss on Extinguishment of Debt. For the three months ended March 31, 2024, the loss on extinguishment of debt was related to USAC's redemption of its $725 million aggregate principal amount of 6.875% senior notes.

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."

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 March 31,		
	2024	2023	Change
Equity in earnings of unconsolidated affiliates:			
Citrus	$ 37	$ 34	$ 3
MEP	17	25	(8)
White Cliffs	6	1	5
Explorer	6	8	(2)
Other	32	20	12
Total equity in earnings of unconsolidated affiliates	$ 98	$ 88	$ 10
Adjusted EBITDA related to unconsolidated affiliates[(1)]:			
Citrus	$ 81	$ 79	$ 2
MEP	26	34	(8)
White Cliffs	11	6	5
Explorer	10	13	(3)
Other	43	29	14
Total Adjusted EBITDA related to unconsolidated affiliates	$ 171	$ 161	$ 10
Distributions received from unconsolidated affiliates:			
Citrus	$ 33	$ 48	$ (15)
MEP	23	33	(10)
White Cliffs	11	5	6
Explorer	8	8	—
Other	32	23	9
Total distributions received from unconsolidated affiliates	$ 107	$ 117	$ (10)

(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 March 31,		
	2024	2023	Change
Natural gas transported (BBtu/d)	14,177	14,697	(520)
Withdrawals from storage natural gas inventory (BBtu)	8,230	6,000	2,230
Revenues	$ 918	$ 1,290	$ (372)
Cost of products sold	487	985	(498)
Segment margin	431	305	126
Unrealized losses on commodity risk management activities	64	174	(110)
Operating expenses, excluding non-cash compensation expense	(53)	(62)	9
Selling, general and administrative expenses, excluding non-cash compensation expense	(12)	(14)	2
Adjusted EBITDA related to unconsolidated affiliates	7	6	1
Other	1	—	1
Segment Adjusted EBITDA	$ 438	$ 409	$ 29

Volumes. For the three months ended March 31, 2024 compared to the same period last year, transported volumes decreased primarily due to decreased production from our Haynesville assets.

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

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Change
Transportation fees	$ 222	$ 216	$ 6
Natural gas sales and other (excluding unrealized gains and losses)	251	176	75
Retained fuel (excluding unrealized gains and losses)	8	15	(7)
Storage margin (excluding unrealized gains and losses and fair value inventory adjustments)	14	72	(58)
Unrealized losses on commodity risk management activities and fair value inventory adjustments	(64)	(174)	110
Total segment margin	$ 431	$ 305	$ 126

Segment Adjusted EBITDA. For the three months ended March 31, 2024 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impact of the following:

- an increase of $75 million in realized natural gas sales and other primarily due to higher pipeline optimization from physical sales and settled derivatives;
- a decrease of $9 million in operating expenses primarily due to a change related to fuel consumption that is offset in cost of goods sold in 2024; and
- an increase of $6 million in transportation fees primarily due to increased demand volumes and new contracts on our Texas system; partially offset by
- a decrease of $58 million in storage margin primarily due to lower storage optimization from settled derivatives; and
- a decrease of $7 million in retained fuel margin primarily due to a change related to fuel consumption that is offset in operating expenses in 2024.

Interstate Transportation and Storage

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Change
Natural gas transported (BBtu/d)	17,665	16,818	847
Natural gas sold (BBtu/d)	23	22	1
Revenues	$ 602	$ 634	$ (32)
Cost of products sold	1	2	(1)
Segment margin	601	632	(31)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(203)	(186)	(17)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(33)	(31)	(2)
Adjusted EBITDA related to unconsolidated affiliates	118	121	(3)
Segment Adjusted EBITDA	$ 483	$ 536	$ (53)

Volumes. For the three months ended March 31, 2024 compared to the same period last year, transported volumes increased primarily due to more capacity sold and higher utilization on our Transwestern, Tiger, Trunkline and Gulf Run systems due to increased demand.

Segment Adjusted EBITDA. For the three months ended March 31, 2024 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impact of the following:

- a decrease of $31 million in segment margin primarily due to a $20 million decrease in operational gas sales resulting from lower prices, an $18 million decrease due to the realization in the prior period of certain amounts related to a shipper bankruptcy and a $6 million decrease in parking revenue. These decreases were partially offset by a $12 million increase in transportation revenue from several of our interstate pipeline systems due to higher contracted volumes at higher rates;

- an increase of $17 million in operating expenses primarily due to a $14 million increase in unplanned maintenance project costs and a $5 million increase in employee costs, partially offset by a $2 million decrease in electricity costs;
- an increase of $2 million in selling, general and administrative expenses primarily due to an increase in professional fees and employee-related costs; and
- a decrease of $3 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to a decrease of $8 million from our Midcontinent Express Pipeline joint venture due to capacity sold at lower rates, partially offset by an increase of $4 million from our Southeast Supply Header joint venture due to capacity sold at higher rates and a $2 million increase from our Citrus joint venture due to revenues from new projects.

Midstream

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Change
Gathered volumes (BBtu/d)	19,922	19,750	172
NGLs produced (MBbls/d)	890	811	79
Equity NGLs (MBbls/d)	52	40	12
Revenues	$ 2,774	$ 2,754	$ 20
Cost of products sold	1,719	1,781	(62)
Segment margin	1,055	973	82
Operating expenses, excluding non-cash compensation expense	(323)	(288)	(35)
Selling, general and administrative expenses, excluding non-cash compensation expense	(44)	(50)	6
Adjusted EBITDA related to unconsolidated affiliates	6	5	1
Other	2	1	1
Segment Adjusted EBITDA	$ 696	$ 641	$ 55

Volumes. For the three months ended March 31, 2024 compared to the same period last year, gathered volumes and NGL production increased primarily due to recently acquired assets and higher volumes from existing customers.

Segment Adjusted EBITDA. For the three months ended March 31, 2024 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impact of the following:

- an increase of $84 million due to recently acquired assets and higher volumes in the Permian region;
- a decrease of $6 million in selling, general and administrative expenses due to a $5 million decrease in workers' compensation reserve and a $2 million decrease in legal expenses; and
- an increase of $1 million in Adjusted EBITDA related to unconsolidated affiliates due to recently acquired assets; partially offset by
- an increase of $35 million in operating expenses primarily due to a $27 million increase from both recently acquired assets and assets placed in service as well as an $8 million increase in employee costs; and
- a decrease of $2 million due to lower natural gas prices of $5 million, partially offset by higher NGL prices of $3 million.

NGL and Refined Products Transportation and Services

	Three Months Ended March 31,		
	2024	2023	Change
NGL transportation volumes (MBbls/d)	2,087	1,984	103
Refined products transportation volumes (MBbls/d)	573	501	72
NGL and refined products terminal volumes (MBbls/d)	1,395	1,344	51
NGL fractionation volumes (MBbls/d)	1,053	949	104
Revenues	$ 6,526	$ 5,603	$ 923
Cost of products sold	5,319	4,402	917
Segment margin	1,207	1,201	6
Unrealized (gains) losses on commodity risk management activities	22	(31)	53
Operating expenses, excluding non-cash compensation expense	(228)	(221)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(42)	(38)	(4)
Adjusted EBITDA related to unconsolidated affiliates	30	28	2
Segment Adjusted EBITDA	$ 989	$ 939	$ 50

Volumes. For the three months ended March 31, 2024 compared to the same period last year, NGL transportation volumes increased primarily due to higher volumes from the Permian region, on our Mariner East pipeline system and on our Gulf Coast export pipelines.

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 NGL Complex.

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

	Three Months Ended March 31,		
	2024	2023	Change
Transportation margin	$ 615	$ 562	$ 53
Fractionators and refinery services margin	233	210	23
Terminal services margin	209	200	9
Storage margin	79	79	—
Marketing margin	93	119	(26)
Unrealized gains (losses) on commodity risk management activities	(22)	31	(53)
Total segment margin	$ 1,207	$ 1,201	$ 6

Segment Adjusted EBITDA. For the three months ended March 31, 2024 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impact of the following:

- an increase of $53 million in transportation margin primarily due to a $20 million increase resulting from higher throughput and contractual rate escalations on our Mariner East pipeline system, a $15 million increase resulting from higher throughput and contractual rate escalations on our Texas y-grade pipeline system, a $15 million increase from higher throughput and contractual rate escalations on our refined product pipelines and a $9 million increase from higher throughput and contractual rate escalations on our Mariner West pipeline. These increases were partially offset by intrasegment charges of $6 million which were fully offset within our marketing margin;
- an increase of $23 million in fractionators and refinery services margin primarily due to a $19 million increase resulting from higher throughput and contractual rate escalations at our Mont Belvieu fractionators and a $4 million increase from our refinery services business; and
- an increase of $9 million in terminal services margin primarily due to a $4 million increase due to higher throughput from our refined product marketing terminals, a $3 million increase from higher export volumes loaded at our Nederland

Terminal and a $2 million increase from our Marcus Hook Terminal due to higher throughput and contractual rate escalations; partially offset by

- a decrease of $26 million in marketing margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to lower gains from the optimization of hedged NGL and refined product inventories. This decrease was partially offset by intrasegment margin of $6 million which was fully offset within our transportation margin;
- an increase of $7 million in operating expenses primarily from recently acquired assets; and
- an increase of $4 million in selling, general and administrative expenses primarily due to a $2 million increase in employee costs and a $2 million increase in overhead expenses.

Crude Oil Transportation and Services

	Three Months Ended March 31,		
	2024	2023	Change
Crude oil transportation volumes (MBbls/d)	6,102	4,238	1,864
Crude oil terminal volumes (MBbls/d)	3,241	2,940	301
Revenues	$ 7,638	$ 6,080	$ 1,558
Cost of products sold	6,594	5,374	1,220
Segment margin	1,044	706	338
Unrealized losses on commodity risk management activities	19	2	17
Operating expenses, excluding non-cash compensation expense	(188)	(153)	(35)
Selling, general and administrative expenses, excluding non-cash compensation expense	(36)	(31)	(5)
Adjusted EBITDA related to unconsolidated affiliates	9	1	8
Other	—	1	(1)
Segment Adjusted EBITDA	$ 848	$ 526	$ 322

Volumes. For the three months ended March 31, 2024 compared to the same period last year, crude oil transportation volumes were higher across all regions. Texas pipeline system volumes were higher due to continued growth on our gathering systems and contributions from recently acquired assets. Bakken Pipeline volumes were also higher due to lower impacts on basin production from winter weather compared to the prior year. Midcontinent systems were higher, driven by contributions from recently acquired assets. Bakken gathering volumes increased, driven by higher production in the basin as well as contributions from recently acquired assets. Volumes on our Bayou Bridge Pipeline were also slightly higher. Crude terminal volumes were higher due to growth in Permian and Bakken production, stronger Gulf Coast refinery utilization and contributions from recently acquired assets.

Segment Adjusted EBITDA. For the three months ended March 31, 2024 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 impact of the following:

- an increase of $355 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $168 million increase from recently acquired assets, a $122 million increase from higher throughput volumes on our crude pipelines, a $60 million increase from our crude oil acquisition and marketing business primarily due to higher volumes and more favorable optimization conditions and a $4 million increase from our Gulf Coast terminals due to higher throughput and exports; and
- an increase of $8 million in Adjusted EBITDA related to unconsolidated affiliates due to recently acquired assets and higher volumes on our White Cliffs crude pipeline; partially offset by
- an increase of $5 million in selling, general and administrative expenses primarily due to recently acquired assets; and
- an increase of $35 million in operating expenses primarily due to a $33 million increase from recently acquired assets.

Investment in Sunoco LP

	Three Months Ended March 31,		
	2024	2023	Change
Revenues	$ 5,499	$ 5,362	$ 137
Cost of products sold	5,015	4,987	28
Segment margin	484	375	109
Unrealized (gains) losses on commodity risk management activities	13	(11)	24
Operating expenses, excluding non-cash compensation expense	(105)	(97)	(8)
Selling, general and administrative expenses, excluding non-cash compensation expense	(32)	(25)	(7)
Adjusted EBITDA related to unconsolidated affiliates	3	3	—
Inventory valuation adjustments	(130)	(29)	(101)
Other	9	5	4
Segment Adjusted EBITDA	$ 242	$ 221	$ 21

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

Segment Adjusted EBITDA. For the three months ended March 31, 2024 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment increased primarily due to the net impact of the following:

- an increase in the profit on motor fuel sales of $25 million primarily due to a 9% increase in gallons sold, partially offset by a decrease in profit per gallon; and
- an increase in non-motor fuel sales and lease profit of $11 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 $15 million, including other operating expense, general and administrative expense and lease expense, primarily due to recent acquisitions of refined product terminals and the transmix processing and terminal facility.

Investment in USAC

	Three Months Ended March 31,		
	2024	2023	Change
Revenues	$ 229	$ 197	$ 32
Cost of products sold	36	34	2
Segment margin	193	163	30
Operating expenses, excluding non-cash compensation expense	(39)	(32)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(15)	(13)	(2)
Segment Adjusted EBITDA	$ 139	$ 118	$ 21

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

Segment Adjusted EBITDA. For the three months ended March 31, 2024 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment increased primarily due to the net impact of the following:

- an increase of $30 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 $7 million in operating expenses primarily due to higher employee costs associated with increased revenue-generating horsepower.

All Other

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023	Change
Revenues	$ 466	$ 544	$ (78)
Cost of products sold	451	502	(51)
Segment margin	15	42	(27)
Unrealized (gains) losses on commodity risk management activities	23	(4)	27
Operating expenses, excluding non-cash compensation expense	(6)	(6)	—
Selling, general and administrative expenses, excluding non-cash compensation expense	(12)	(9)	(3)
Adjusted EBITDA related to unconsolidated affiliates	1	—	1
Other and eliminations	24	20	4
Segment Adjusted EBITDA	$ 45	$ 43	$ 2

Amounts reflected in our all other segment primarily include:

- our natural gas marketing operations;
- our wholly-owned natural gas compression operations; and
- our investment in coal handling facilities.

Segment Adjusted EBITDA. For the three months ended March 31, 2024 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment increased primarily due to the net impact of the following:

- an increase of $8 million in our natural gas marketing business from the sale of stored natural gas; and
- an increase of $2 million due to improved power trading market conditions; partially offset by
- a decrease of $3 million in our dual drive compression business due to lower margin resulting from lower natural gas prices; and
- a decrease of $2 million due to lower 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 2024 to be within the following ranges (including capitalized interest and overhead and only our proportionate share for joint ventures, but excluding capital expenditures related to our investments in Sunoco LP and USAC):

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 60	$ 65	$ 60	$ 65
Interstate transportation and storage	160	170	205	210
Midstream	775	875	225	230
NGL and refined products transportation and services	1,450	1,500	120	125
Crude oil transportation and services	250	280	150	155
All other (including eliminations)	105	110	75	80
Total capital expenditures	$ 2,800	$ 3,000	$ 835	$ 865

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 has not announced its updated expectations for growth and maintenance capital expenditures in 2024, subsequent to its completion of the NuStar acquisition.

USAC currently plans to spend approximately $32 million in maintenance capital expenditures and between $115 million and $125 million in expansion capital expenditures for the full year 2024.

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.

Three months ended March 31, 2024 compared to three months ended March 31, 2023. Cash provided by operating activities during 2024 was $3.77 billion compared to $3.35 billion for 2023, and net income was $1.69 billion for 2024 and $1.45 billion for 2023. The difference between net income and net cash provided by operating activities for the three months ended March 31, 2024 primarily consisted of net changes in operating assets and liabilities (net of effects of acquisitions and divestitures) of $873 million and non-cash items totaling $1.14 billion.

The non-cash activity in 2024 and 2023 consisted primarily of depreciation, depletion and amortization of $1.25 billion and $1.06 billion, respectively, non-cash compensation expense of $46 million and $37 million, respectively, favorable inventory valuation adjustments of $130 million and $29 million, respectively, and deferred income taxes of $67 million and $53 million, respectively. Net income also included equity in earnings of unconsolidated affiliates of $98 million and $88 million in 2024 and 2023, 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 $84 million in 2024 and $87 million in 2023.

Cash paid for interest, net of interest capitalized, was $444 million and $406 million for the three months ended March 31, 2024 and 2023, respectively. Interest capitalized was $23 million and $15 million for the three months ended March 31, 2024 and 2023, 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.

Three months ended March 31, 2024 compared to three months ended March 31, 2023. Cash used in investing activities during 2024 was $1.20 billion compared to $803 million for 2023. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2024 were $770 million compared to $837 million for 2023. Additional detail related to our capital expenditures is provided in the table below.

In 2024, Sunoco LP paid $185 million in cash for the acquisition of liquid fuels terminals in Amsterdam, Netherlands and Bantry Bay, Ireland from Zenith Energy. In 2024, we paid $84 million to acquire the outstanding noncontrolling interest in Edwards Lime Gathering, LLC, which is now a wholly owned subsidiary, and we also paid $180 million for other acquisitions.

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 three months ended March 31, 2024:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$ 6	$ 8	$ 14
Interstate transportation and storage	29	20	49
Midstream	138	40	178
NGL and refined products transportation and services	205	15	220
Crude oil transportation and services	69	20	89
Investment in Sunoco LP	27	14	41
Investment in USAC	105	6	111
All other (including eliminations)	14	12	26
Total capital expenditures	$ 593	$ 135	$ 728

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.

Three months ended March 31, 2024 compared to three months ended March 31, 2023. Cash used in financing activities during 2024 was $791 million compared to $2.47 billion for 2023. During 2024, we had a net increase in our debt level of $1.88 billion compared to a net decrease of $1.02 billion for 2023. In 2024, we paid debt issuance costs of $60 million, paid $895 million in cash for the redemption of our Series C and Series D Preferred Units and paid $37 million in cash to redeem a portion of the outstanding Crestwood Niobrara LLC preferred units. In 2024, USAC paid $749 million in cash for investments in government securities in connection with the legal defeasance of senior notes.

In 2024 and 2023, we paid distributions of $1.13 billion and $1.00 billion, respectively, to our partners. In 2024 and 2023, we paid distributions of $421 million and $441 million, respectively, to noncontrolling interests. In 2024 and 2023, we paid distributions of $22 million and $12 million, respectively, to our redeemable noncontrolling interests.

In 2024 and 2023, we received capital contributions of $637 million and $3 million, respectively, in cash from noncontrolling interests.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	March 31, 2024	December 31, 2023
Energy Transfer Indebtedness:		
Notes and Debentures[(1)] [(2)]	$ 45,234	$ 43,016
Five-Year Credit Facility[(2)]	—	1,412
Subsidiary Indebtedness:		
Transwestern Senior Notes	250	250
Bakken Project Senior Notes[(2)]	1,850	1,850
Sunoco LP Senior Notes and lease-related obligations [(2)]	3,194	3,194
USAC Senior Notes[(2)]	1,750	1,475
Sunoco LP Credit Facility	625	411
USAC Credit Facility	736	872
Other long-term debt	15	18
Net unamortized premiums, discounts and fair value adjustments	105	127
Deferred debt issuance costs	(283)	(237)
Total debt	53,476	52,388
Less: current maturities of long-term debt[(3)]	1,181	1,008
Long-term debt, less current maturities	$ 52,295	$ 51,380

(1) As of March 31, 2024, this balance included a total of $2.92 billion aggregate principal amount of senior notes due on or before March 31, 2025, 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 March 31, 2024, 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 were repaid in April 2024, as described below under “Recent Transactions.” The Partnership’s proportional ownership in the Bakken Pipeline entities is 36.4%.

Recent Transactions

Energy Transfer Senior Notes Redemptions

During the first quarter of 2024, the Partnership redeemed its $1.15 billion aggregate principal amount of 5.875% Senior Notes due January 2024, $350 million aggregate principal amount of 4.90% Senior Notes due February 2024 and $82 million aggregate principal amount of 7.60% Senior Notes due February 2024 using proceeds from its January 2024 notes issuance described below.

In April 2024, the Partnership redeemed its $500 million aggregate principal amount of 4.25% Senior Notes due April 2024, $750 million aggregate principal amount of 4.50% Senior Notes due April 2024 and $450 million aggregate principal amount of 8.00% Senior Notes due April 2029 using cash on hand and proceeds from its Five-Year Credit Facility (defined below).

Bakken Project Debt Redemption

In April 2024, the Bakken Pipeline entities redeemed $1.00 billion aggregate principal amount of 3.90% Senior Notes due April 2024 using proceeds from member contributions. The Partnership indirectly owns 36.4% of the ownership interests in the Bakken Pipeline entities.

Energy Transfer January 2024 Notes Issuance

In January 2024, the Partnership issued $1.25 billion aggregate principal amount of 5.55% Senior Notes due 2034, $1.75 billion aggregate principal amount of 5.95% Senior Notes due 2054 and $800 million aggregate principal amount of 8.00% fixed-to-fixed reset rate Junior Subordinated Notes due 2054. The Partnership used the net proceeds to refinance existing indebtedness, including borrowings under its Five-Year Credit Facility, to redeem its outstanding Series C Preferred Units and Series D

Preferred Units and for general partnership purposes. The Partnership will also use the net proceeds to redeem its outstanding Series E Preferred Units in May 2024.

Sunoco LP April 2024 Notes Issuance

On April 30, 2024, Sunoco LP issued $750 million of 7.000% senior notes due 2029 and $750 million of 7.250% senior notes due 2032 in a private offering. Sunoco LP used the net proceeds from the offering to (i) repay certain outstanding indebtedness of NuStar, in connection with the merger between Sunoco LP and NuStar, (ii) fund the redemption of NuStar's preferred units in connection with the merger and (iii) pay offering fees and expenses.

USAC March 2024 Notes Issuance

In March 2024, USAC issued $1.00 billion aggregate principal amount of 7.125% Senior Notes due 2029. The net proceeds from this issuance were used to repay a portion of existing borrowings under USAC’s revolving credit facility, to redeem its $725 million aggregate principal amount of 6.875% senior notes due 2026, which constituted a legal defeasance under GAAP (the “Defeasance”), and for general partnership purposes.

The Defeasance required a cash outlay in the net amount of $749 million, which was used to purchase U.S. government securities. These securities generated sufficient cash upon maturity to fund interest payments on the senior notes due 2026 occurring between the effective date of the Defeasance through April 4, 2024, when the senior notes due 2026 were redeemed at par, as well as fund the redemption of the senior notes due 2026 in full. As a result of the Defeasance, USAC recognized a loss on early extinguishment of debt of $5 million for the three months ended March 31, 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 March 31, 2024, the Five-Year Credit Facility had no outstanding borrowings and no outstanding commercial paper. The amount available for future borrowings was $4.97 billion, after accounting for outstanding letters of credit in the amount of $29 million.

Sunoco LP Credit Facility

As of March 31, 2024, Sunoco LP’s credit facility had $625 million of outstanding borrowings and $5 million in standby letters of credit and matures in May 2029 (as amended in May 2024). The amount available for future borrowings at March 31, 2024 was $870 million. The weighted average interest rate on the total amount outstanding as of March 31, 2024 was 7.18%.

USAC Credit Facility

As of March 31, 2024, USAC’s credit facility, which matures in December 2026, had $736 million of outstanding borrowings and $1 million outstanding letters of credit. As of March 31, 2024, USAC’s credit facility had $863 million of remaining unused availability of which, due to restrictions related to compliance with the applicable financial covenants, $429 million was available to be drawn. The weighted average interest rate on the total amount outstanding as of March 31, 2024 was 8.00%.

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 March 31, 2024.

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, 2023 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2023	February 7, 2024	February 20, 2024	$ 0.3150
March 31, 2024	May 13, 2024	May 20, 2024	0.3175

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	Series B [1]	Series C	Series D	Series E	Series F [1]	Series G [1]	Series H [1]	Series I
December 31, 2023	February 1, 2024	February 15, 2024	$ 24.710	$ 33.125	$ 0.6075	$ 0.6199	$ 0.475	$ —	$ —	$ —	$ 0.2111
March 31, 2024	May 1, 2024	May 15, 2024	23.992	—	—	—	0.475	33.750	35.630	32.500	0.2111

(1) Series B, Series F, Series G and Series H distributions are currently paid on a semi-annual basis. Pursuant to its terms, distributions on the Series B Preferred Units will begin to be paid quarterly on February 15, 2028.

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[1]	May 15, 2024	5.161 %	0.26161 %	Three-month SOFR

(1) The Partnership will redeem all of its outstanding Series E Preferred Units on May 15, 2024.

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, 2023 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2023	February 7, 2024	February 20, 2024	$ 0.8420
March 31, 2024	May 13, 2024	May 20, 2024	0.8756

Cash Distributions Paid by USAC

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2023 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2023	January 22, 2024	February 2, 2024	$ 0.525
March 31, 2024	April 22, 2024	May 3, 2024	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 16, 2024. 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 Sunoco LP's business with that of NuStar.

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, 2023 filed with the SEC on February 16, 2024. 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, 2023 filed with the SEC on February 16, 2024, 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, 2023. Since December 31, 2023, there have been no material changes to our primary market risk exposures or how those exposures are managed.

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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.

	March 31, 2024			December 31, 2023		
	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	5,653	$ —	$ 1	(1,878)	$ 4	$ —
Basis Swaps IFERC/NYMEX [1]	(36,158)	(6)	1	(171,185)	16	4
Swing Swaps IFERC	—	—	—	(900)	—	—
Options – Puts	—	—	—	1,900	(2)	—
Options – Calls	250	—	—	250	—	—
Power (Megawatt):						
Forwards	220,220	1	1	155,600	1	—
Futures	(974,635)	3	2	(464,897)	—	1
Options – Puts	32,000	—	—	136,000	—	—
Crude (MBbls):						
Options – Puts	—	—	—	(15)	—	—
Options – Calls	—	—	—	(20)	—	—
NGL/Refined Products (MBbls):						
Options – Puts	33	—	—	121	(1)	—
Options – Calls	34	—	—	(43)	(1)	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	71,395	6	1	124,210	4	1
Swing Swaps IFERC	(104,643)	—	1	(96,828)	18	1
Fixed Swaps/Futures	10,865	(11)	2	7,125	12	2
Forward Physical Contracts	5,790	9	3	(1,751)	8	1
NGLs (MBbls) – Forwards/Swaps	(3,113)	18	13	(13,870)	20	43
Crude (MBbls) – Forwards/Swaps	(1,780)	(10)	19	(2,674)	8	5
Refined Products (MBbls) – Futures	(2,760)	(16)	32	(4,548)	17	38
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(49,858)	(6)	2	(39,013)	1	1
Fixed Swaps/Futures	(49,858)	25	15	(39,013)	45	9

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

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

Interest Rate Risk

As of March 31, 2024, we and our subsidiaries had $1.96 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $20 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 USAC's interest rate swap outstanding which was not designated as a hedge for accounting purposes:

		Notional Amount Outstanding	
Term	Type	March 31, 2024	December 31, 2023
December 2025	Pay a fixed rate of 3.9725% and receive a floating rate based on SOFR	$ 700	$ 700

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 $13 million as of March 31, 2024. 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 with an aggregate liquidation preference of $950 million as of March 31, 2024, for which distributions are based on a floating rate. A hypothetical change of 100 basis points in interest rates would result in a net change in preferred unit distributions of $10 million annually.

As of March 31, 2024, the Partnership had $600 million of Floating Rate Junior Subordinated Notes outstanding as well as the Series A Preferred Units, the floating rates 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 the Series A 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 March 31, 2024 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

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 March 31, 2024 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 16, 2024 and Note 10 in “Item 1. Financial Statements” in this Quarterly Report on Form 10-Q for the quarter ended March 31, 2024.

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 could result in monetary sanctions in excess of $0.3 million.

On February 3, 2022, the State of New Mexico, ex rel. Hector Balderas, Attorney General filed a complaint against ETO, Transwestern, Kinder Morgan, Inc., El Paso Natural Gas Company, L.L.C. and Northwest Pipeline LLC in Cause No. D-101-CV-2022-00174 in the First Judicial District Court, County of Santa Fe, State of New Mexico, seeking to recover statewide damages for contamination with PCBs used for decades by the oil and gas industry in the operation and maintenance of pipeline infrastructure. The complaint alleges discharge or release of PCBs into the natural environment from compressor stations in connection with the operation of the Transwestern Pipeline. The parties have largely completed document discovery and begin depositions in late May 2024. Once discovery has been completed, the Partnership will be able to provide an assessment of the potential outcome or range of potential liability, if any. Trial has been set for January 2025.

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

Sunoco LP’s acquisitions of NuStar and the Zenith terminals in May 2024 and March 2024, respectively, present several risks. Certain risks associated with these recently acquired businesses are described below, to the extent those risks represent new risks related to our business or existing risks that have become more significant. In some cases, certain elements of the risks described below are similar to the risks associated with our existing business that have recently been disclosed; however, such disclosure is repeated herein to fully describe the relevant risk.

The following risk factors should be read in conjunction with our risk factors described in “Part I — Item 1A. Risk Factors” of our Annual Report on Form 10-K for the year ended December 31, 2023.

Extended periods of reduced demand for or supply of crude oil, refined products, renewable fuels and anhydrous ammonia could have an adverse impact on Sunoco LP’s results of operations, cash flows and ability to make distributions to its unitholders.

A significant portion of Sunoco LP’s business is ultimately dependent upon the demand for and supply of the crude oil, refined products, renewable fuels and anhydrous ammonia it transports in pipelines and store in its terminals. Market prices for these products are subject to wide fluctuation in response to changes in global and regional supply and demand that are beyond Sunoco LP’s control. Increases in the price of crude oil may result in a lower demand for refined products that Sunoco LP transports, stores and markets, including fuel oil, while sustained low prices may lead to reduced production in the markets served by Sunoco LP’s pipelines and storage terminals.

Any sustained decrease in demand for crude oil, refined products, renewable fuels or anhydrous ammonia in the markets Sunoco LP’s pipelines and terminals serve that extends beyond the expiration of its existing throughput and deficiency agreements could result in a significant reduction in throughputs in its pipelines and storage in its terminals, which would reduce Sunoco LP’s cash flows and impair Sunoco LP’s ability to make distributions to its unitholders. Factors that tend to decrease market demand include:

- a recession, high interest rates, inflation or other adverse economic conditions that result in lower spending by consumers on gasoline, diesel and travel;
- events that negatively impact global economic activity, travel and demand generally;

- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline;
- an increase in aggregate automotive engine fuel economy;
- new government and regulatory actions or court decisions requiring the phase out or reduced use of gasoline-fueled vehicles;
- the increased use of and public demand for use of alternative fuel sources or electric vehicles;
- an increase in the market price of crude oil that increases refined product prices, which may reduce demand for refined products and increase demand for alternative products; and
- adverse weather events resulting in decreased corn acres planted, which may reduce demand for anhydrous ammonia.

Similarly, any sustained decrease in the supply of crude oil, refined products, renewable fuels or anhydrous ammonia in markets Sunoco LP serves could result in a significant reduction in throughputs in its pipelines and storage in its terminals, which would reduce Sunoco LP's cash flows and undermine Sunoco LP's ability to make distributions to its unitholders. Factors that tend to decrease supply and, by extension, utilization of Sunoco LP's pipelines and terminals include:

- prolonged periods of low prices for crude oil and refined products that result in decreased exploration and development activity and reduced production in markets served by Sunoco LP's pipelines and storage terminals;
- macroeconomic forces affecting, or actions taken by, oil and gas producing nations that impact the supply of and prices for crude oil and refined products;
- a lack of drilling services, equipment or skilled personnel available to producers to accommodate production needs;
- changes in laws, regulations, sanctions or taxation that directly or indirectly delay supply or production or increase the cost of production of refined products; and
- political unrest or hostilities, activist interference and the resulting governmental response thereto.

Sunoco LP's operations are subject to federal, state and local laws and regulations, in the U.S., in Mexico and in Europe, relating to environmental, health, safety and security that require it to make substantial expenditures.

Sunoco LP's operations are subject to increasingly stringent international, federal, state and local environmental, health, safety and security laws and regulations. Transporting, storing and distributing hazardous materials, including petroleum products, entails the risk of releasing these products into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies including for damages to natural resources, personal injury or property damages to private parties and significant business interruption. Further, Sunoco LP's pipeline facilities are subject to the pipeline integrity and safety regulations of various federal and state regulatory agencies, as well as cybersecurity directives. In recent years, increased regulatory focus on pipeline integrity, safety and security has resulted in various proposed or adopted regulations. The implementation of these regulations has required, and the adoption of future regulations could require Sunoco LP to make additional capital or other expenditures, including to install new or modified safety or security measures, or to conduct new or more extensive inspection and maintenance programs.

Legislative action and regulatory initiatives have resulted in, and could in the future result in, changes to operating permits, imposition of carbon taxes or methane fees, material changes in operations, increased capital expenditures and operating costs, increased costs of the goods Sunoco LP transports and/or decreased demand for products it handles. Future impacts cannot be assessed with certainty at this time. Required expenditures to modify operations or install pollution control equipment or release prevention and containment systems or other environmental, health, safety or security measures could materially and adversely affect Sunoco LP's business, financial condition, results of operations and liquidity if these expenditures, as with all costs, are not ultimately reflected in the tariffs and other fees Sunoco LP receives for their services.

Sunoco LP owns or leases a number of properties that were used to transport, store or distribute products for many years before Sunoco LP acquired them; therefore, such properties were operated by third parties whose handling, disposal or release of products and wastes was not under Sunoco LP's control. Environmental laws and regulations could impose obligations to conduct assessment or remediation efforts at Sunoco LP's facilities, third-party sites where Sunoco LP take wastes for disposal, or where wastes have migrated. Environmental laws and regulations also may impose joint and several liability on Sunoco LP for the conduct of third parties or for actions that complied with applicable requirements when taken, regardless of negligence or fault. If Sunoco LP were to incur a significant liability pursuant to environmental, health, safety or security laws or regulations, such a liability could have a material adverse effect on Sunoco LP's financial position.

Sunoco LP operates assets outside of the United States, which exposes Sunoco LP to different legal and regulatory requirements and additional risk.

A portion of Sunoco LP's revenues are generated from its assets located in northern Mexico and Europe. Sunoco LP's foreign operations are subject to various risks that could have a material adverse effect on its business, results of operations and financial condition, including political and economic instability from civil unrest; labor strikes; war and other armed conflict; inflation; currency fluctuations, devaluation and conversion restrictions or other factors. Any deterioration of social, political, labor or economic conditions, including the increasing threat of terrorist organizations and drug cartels in Mexico, or affecting a customer with whom Sunoco LP does business, as well as difficulties in staffing, obtaining necessary equipment and supplies and managing foreign operations, may adversely affect Sunoco LP's operations or financial results. Sunoco LP is also exposed to the risk of foreign and domestic governmental actions that may: impose additional costs on Sunoco LP; delay permits or otherwise impede Sunoco LP's operations; limit or disrupt markets for Sunoco LP's operations, restrict payments or limit the movement of funds; impose sanctions on or otherwise restrict Sunoco LP's ability to conduct business with certain customers or persons or in certain countries; or result in the deprivation of contract rights. Sunoco LP's operations outside the United States may also be affected by changes in trade protection laws, policies and measures, and other regulatory requirements affecting trade and investment, including the Foreign Corrupt Practices Act and foreign laws prohibiting corrupt payments, as well as travel restrictions and import and export regulations.

Sunoco LP could be subject to liabilities from its assets that predate its acquisition of those assets, but that are not covered by indemnification rights Sunoco LP has against the sellers of the assets.

Sunoco LP has acquired assets and businesses and is not always indemnified by the seller for liabilities that precede its ownership. In addition, in some cases, Sunoco LP has indemnified the previous owners and operators of acquired assets or businesses. Some of its assets have been used for many years to transport and store crude oil and refined products, and past releases could require costly future remediation. If a significant release or event occurred in the past, the liability for which was not retained by the seller, or for which indemnification by the seller is not available, it could adversely affect Sunoco LP's financial position and results of operations. Conversely, if liabilities arise from assets Sunoco LP has sold, Sunoco LP could incur costs related to those liabilities if the buyer possesses valid indemnification rights against Sunoco LP with respect to those assets.

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	Fourth Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated November 3, 2023 (incorporated by reference to Exhibit 3.2 to Form 8-K (File No. 1-32740) filed November 6, 2023)
4.1	Third Supplemental Indenture, dated as of January 25, 2024, between Energy Transfer LP, as issuer, and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-32740) filed January 25, 2024)
4.2	Fourth Supplemental Indenture, dated as of January 25, 2024, between Energy Transfer LP, as issuer, and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K (File No. 1-32740) filed January 25, 2024)
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: May 9, 2024

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: May 9, 2024

/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: May 9, 2024

/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: May 9, 2024

/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 March 31, 2024, 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: May 9, 2024

/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 March 31, 2024, 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: May 9, 2024

/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 March 31, 2024, 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: May 9, 2024

/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.