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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 June 30, 2022

or

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

Commission file number 1-32740

ENERGY TRANSFER LP

(Exact name of registrant as specified in its charter)

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

8111 Westchester Drive, Suite 600, Dallas, Texas 75225

(Address of principal executive offices) (zip code)

(214) 981-0700

(Registrant’s telephone number, including area code)

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

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

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

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

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

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

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

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

At July 29, 2022, the registrant had 3,086,970,948 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 (loss)
BBtu	billion British thermal units
Citrus	Citrus, LLC, a 50/50 joint venture which owns FGT
Dakota Access	Dakota Access, LLC, a less than wholly-owned subsidiary of Energy Transfer
Enable	Enable Midstream Partners, LP, a Delaware limited partnership
Energy Transfer Canada	Energy Transfer Canada ULC, a less than wholly-owned subsidiary of Energy Transfer
Energy Transfer R&M	Energy Transfer (R&M), LLC (formerly Sunoco (R&M), LLC)
Energy Transfer Preferred Units	Collectively, the Series A Preferred Units, Series B Preferred Units, Series C Preferred Units, Series D Preferred Units, Series E Preferred Units, Series F Preferred Units, Series G Preferred Units and Series H Preferred Units
ETC Tiger	ETC Tiger Pipeline, LLC, a wholly-owned subsidiary of Energy Transfer, which owns the Tiger Pipeline
ETO	Energy Transfer Operating, L.P., formerly a less than 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
FGT	Florida Gas Transmission Company, LLC, a wholly-owned subsidiary of Citrus
GAAP	accounting principles generally accepted in the United States of America
General Partner	LE GP, LLC, the general partner of Energy Transfer
HFOTCO	Houston Fuel Oil Terminal Company, a wholly-owned subsidiary of Energy Transfer, which owns the Houston Terminal
IFERC	Inside FERC's Gas Market Report
LIBOR	London Interbank Offered Rate
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGL	natural gas liquid, such as propane, butane and natural gasoline
NYMEX	New York Mercantile Exchange
OSHA	Federal Occupational Safety and Health Act
OTC	over-the-counter
Panhandle	Panhandle Eastern Pipe Line Company, LP, a wholly-owned subsidiary of Energy Transfer
Rover	Rover Pipeline LLC, a less than wholly-owned subsidiary of Energy Transfer
SEC	Securities and Exchange Commission
Series A Preferred Units	6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units

Series B Preferred Units	6.625% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series C Preferred Units	7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series D Preferred Units	7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series E Preferred Units	7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units
Series F Preferred Units	6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series G Preferred Units	7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
Series H Preferred Units	6.500% Series H Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units
SCOOP	South Central Oklahoma Oil Province
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
Trunkline	Trunkline Gas Company, LLC, a wholly-owned subsidiary of Panhandle
USAC	USA Compression Partners, LP, a publicly traded partnership, of which Energy Transfer owns the general partner interests and 46.1 million common units
White Cliffs	White Cliffs Pipeline, L.L.C.

PART I – FINANCIAL INFORMATION

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

	June 30, 2022	December 31, 2021
ASSETS		
Current assets:		
Cash and cash equivalents	$ 353	$ 336
Accounts receivable, net	10,163	7,654
Accounts receivable from related companies	122	54
Inventories	2,216	2,014
Income taxes receivable	86	32
Derivative assets	57	10
Other current assets	726	437
Current assets held for sale	1,711	—
Total current assets	15,434	10,537
Property, plant and equipment	103,724	103,991
Accumulated depreciation and depletion	(23,856)	(22,384)
Property, plant and equipment, net	79,868	81,607
Investments in unconsolidated affiliates	2,924	2,947
Lease right-of-use assets, net	822	838
Other non-current assets, net	1,561	1,645
Intangible assets, net	5,607	5,856
Goodwill	2,553	2,533
Total assets	$ 108,769	$ 105,963

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)

LIABILITIES AND EQUITY	June 30, 2022	December 31, 2021
Current liabilities:		
Accounts payable	$ 8,897	$ 6,834
Accounts payable to related companies	17	—
Derivative liabilities	13	203
Operating lease current liabilities	44	47
Accrued and other current liabilities	3,413	3,071
Current maturities of long-term debt	2	680
Current liabilities held for sale	1,089	—
Total current liabilities	13,475	10,835
Long-term debt, less current maturities	48,104	49,022
Non-current derivative liabilities	144	193
Non-current operating lease liabilities	801	814
Deferred income taxes	3,611	3,648
Other non-current liabilities	1,376	1,323
Commitments and contingencies		
Redeemable noncontrolling interests	493	783
Equity:		
Limited Partners:		
Preferred Unitholders	6,051	6,051
Common Unitholders	26,507	25,230
General Partner	(3)	(4)
Accumulated other comprehensive income	29	23
Total partners’ capital	32,584	31,300
Noncontrolling interests	8,181	8,045
Total equity	40,765	39,345
Total liabilities and equity	$ 108,769	$ 105,963

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 June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
REVENUES:				
Refined product sales	$ 7,950	$ 4,403	$ 13,396	$ 7,927
Crude sales	6,683	3,911	11,985	6,899
NGL sales	5,896	3,364	11,005	6,270
Gathering, transportation and other fees	2,765	2,255	5,458	4,521
Natural gas sales	2,429	1,007	4,182	6,131
Other	222	161	410	348
Total revenues	25,945	15,101	46,436	32,096
COSTS AND EXPENSES:				
Cost of products sold	21,515	11,505	37,653	22,453
Operating expenses	1,060	867	2,009	1,687
Depreciation, depletion and amortization	1,046	940	2,074	1,894
Selling, general and administrative	211	184	441	385
Impairment losses	—	8	300	11
Total costs and expenses	23,832	13,504	42,477	26,430
OPERATING INCOME	2,113	1,597	3,959	5,666
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(578)	(566)	(1,137)	(1,155)
Equity in earnings of unconsolidated affiliates	62	65	118	120
Losses on extinguishments of debt	—	(1)	—	(8)
Gains (losses) on interest rate derivatives	129	(123)	243	71
Other, net	(18)	18	3	12
INCOME BEFORE INCOME TAX EXPENSE	1,708	990	3,186	4,706
Income tax expense	86	82	77	157
NET INCOME	1,622	908	3,109	4,549
Less: Net income attributable to noncontrolling interests	284	269	489	610
Less: Net income attributable to redeemable noncontrolling interests	12	13	25	25
NET INCOME ATTRIBUTABLE TO PARTNERS	1,326	626	2,595	3,914
General Partner’s interest in net income	1	1	2	4
Preferred Unitholders’ interest in net income	105	86	211	86
Common Unitholders’ interest in net income	$ 1,220	$ 539	$ 2,382	$ 3,824
NET INCOME PER COMMON UNIT:				
Basic	$ 0.40	$ 0.20	$ 0.77	$ 1.41
Diluted	$ 0.39	$ 0.20	$ 0.77	$ 1.41

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 June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Net income	$ 1,622	$ 908	$ 3,109	$ 4,549
Other comprehensive income, net of tax:				
Change in value of available-for-sale securities	(4)	3	(9)	3
Actuarial gain related to pension and other postretirement benefit plans	—	—	7	5
Foreign currency translation adjustments	(30)	12	(19)	24
Change in other comprehensive income from unconsolidated affiliates	6	9	18	—
	(28)	24	(3)	32
Comprehensive income	1,594	932	3,106	4,581
Less: Comprehensive income attributable to noncontrolling interests	270	275	480	622
Less: Comprehensive income attributable to redeemable noncontrolling interests	12	13	25	25
Comprehensive income attributable to partners	$ 1,312	$ 644	$ 2,601	$ 3,934

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, 2021	$ 25,230	$ 6,051	$ (4)	$ 23	$ 8,045	$ 39,345
Distributions to partners	(528)	(80)	—	—	—	(608)
Distributions to noncontrolling interests	—	—	—	—	(307)	(307)
Capital contributions from noncontrolling interests	—	—	—	—	373	373
Other comprehensive income, net of tax	—	—	—	20	5	25
Other, net	17	—	—	—	10	27
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,162	106	1	—	205	1,474
Balance, March 31, 2022	25,881	6,077	(3)	43	8,331	40,329
Distributions to partners	(603)	(131)	(1)	—	—	(735)
Distributions to noncontrolling interests	—	—	—	—	(446)	(446)
Capital contributions from noncontrolling interests	—	—	—	—	24	24
Other comprehensive income, net of tax	—	—	—	(14)	(14)	(28)
Other, net	9	—	—	—	2	11
Net income, excluding amounts attributable to redeemable noncontrolling interests	1,220	105	1	—	284	1,610
Balance, June 30, 2022	$ 26,507	$ 6,051	$ (3)	$ 29	$ 8,181	$ 40,765

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

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)

	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021
OPERATING ACTIVITIES:		
Net income	$ 3,109	$ 4,549
Reconciliation of net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	2,074	1,894
Deferred income taxes	107	133
Inventory valuation adjustments	(121)	(159)
Non-cash compensation expense	61	55
Impairment losses	300	11
Losses on extinguishments of debt	—	8
Distributions on unvested awards	(27)	(13)
Equity in earnings of unconsolidated affiliates	(118)	(120)
Distributions from unconsolidated affiliates	108	100
Other non-cash	(38)	41
Net change in operating assets and liabilities, net of effects of acquisitions	(731)	661
Net cash provided by operating activities	4,724	7,160
INVESTING ACTIVITIES:		
Cash paid for acquisition of Spindletop Assets	(325)	—
Cash paid for all other acquisitions	(264)	—
Capital expenditures, excluding allowance for equity funds used during construction	(1,458)	(1,429)
Contributions in aid of construction costs	35	16
Contributions to unconsolidated affiliates	—	(4)
Distributions from unconsolidated affiliates in excess of cumulative earnings	46	64
Proceeds from sales of other assets	12	24
Net cash used in investing activities	(1,954)	(1,329)
FINANCING ACTIVITIES:		
Proceeds from borrowings	11,798	8,245
Repayments of debt	(12,819)	(13,425)
Preferred Units issued for cash	—	889
Capital contributions from noncontrolling interests	397	63
Distributions to partners	(1,343)	(898)
Distributions to noncontrolling interests	(753)	(760)
Distributions to redeemable noncontrolling interests	(24)	(24)
Debt issuance costs	(9)	(3)
Other, net	—	(3)
Net cash used in financing activities	(2,753)	(5,916)
Increase (decrease) in cash and cash equivalents	17	(85)
Cash and cash equivalents, beginning of period	336	367
Cash and cash equivalents, end of period	$ 353	$ 282

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, 2021, filed with the SEC on February 18, 2022. 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 DIVESTITURE TRANSACTIONS

Woodford Express Acquisition

In August 2022, Energy Transfer entered into an agreement to acquire 100% of the membership interests in Woodford Express, LLC, a Mid-Continent gas gathering and processing system, for approximately $485 million in cash consideration. The system, which is located in the heart of the SCOOP play, has 450 MMcf/d of cryogenic gas processing and treating capacity and over 200 miles of gathering lines, which are connected to Energy Transfer's pipeline network. The transaction is expected to close by the end of the third quarter, subject to customary closing conditions including Hart-Scott-Rodino Act clearance.

Energy Transfer Canada Sale

In March 2022, the Partnership announced a definitive agreement to sell its 51% interest in Energy Transfer Canada. The sale is expected to result in cash proceeds to Energy Transfer of approximately C$340 million (US$264 million at the June 30, 2022 exchange rate), subject to certain purchase price adjustments. The transaction is expected to close by the third quarter of 2022.

Energy Transfer Canada's assets and liabilities were reflected as held for sale in the Partnership's consolidated balance sheet as of June 30, 2022. Energy Transfer Canada's assets and operations are included in the all other segment. Energy Transfer Canada does not meet the criteria to be reflected as discontinued operations in the Partnership's consolidated statement of operations. Based on the anticipated proceeds of the sale, during the three months ended March 31, 2022, the Partnership recorded a write-down on Energy Transfer Canada's assets of $300 million, of which $164 million was allocated to noncontrolling interests and $136 million was reflected in net income attributable to partners.

The following table presents the assets and liabilities classified as held for sale in the Partnership's consolidated balance sheet as of June 30, 2022:

	June 30, 2022
Carrying amounts of assets held for sale	
Cash and cash equivalents	$ 3
Accounts receivable, net	102
Other current assets	7
Property, plant and equipment, net	1,486
Other non-current assets, net	16
Intangible assets, net	97
Total assets held for sale	$ 1,711
Carrying amounts of liabilities held for sale	
Accounts payable	$ 2
Accrued and other current liabilities	58
Long-term debt, including current maturities	543
Other non-current liabilities, net	195
Redeemable noncontrolling interests	291
Total liabilities held for sale	$ 1,089

Spindletop Assets Purchase

In March 2022, the Partnership purchased the membership interests in Caliche Coastal Holdings, LLC (subsequently renamed Energy Transfer Spindletop LLC), which owns an underground storage facility near Mont Belvieu, Texas, for approximately $325 million.

Enable Acquisition

On December 2, 2021, the Partnership completed the acquisition of Enable. As of August 4, 2022, there has been no material changes to the preliminary purchase price allocation disclosed in our Annual Report on Form 10-K for the year ended December 31, 2021, filed with the SEC on February 18, 2022.

Sunoco LP Acquisition

On April 1, 2022, Sunoco LP completed the acquisition of a transmix processing and terminal facility in Huntington, Indiana for $264 million, of which $96 million was allocated to intangible assets, $19 million to goodwill, $72 million to property, plant and equipment, and $77 million to working capital.

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 June 30, 2022 or December 31, 2021.

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

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

	Six Months Ended June 30,	
	2022	2021
Accounts receivable	$ (2,555)	$ (1,946)
Accounts receivable from related companies	(67)	(40)
Inventories	26	234
Other current assets	(333)	(48)
Other non-current assets, net	83	(12)
Accounts payable	2,029	2,207
Accounts payable to related companies	22	(24)
Accrued and other current liabilities	252	326
Other non-current liabilities	98	84
Derivative assets and liabilities, net	(286)	(120)
Net change in operating assets and liabilities, net of effects of acquisitions	$ (731)	$ 661

Non-cash investing and financing activities were as follows:

	Six Months Ended June 30,	
	2022	2021
Accrued capital expenditures	$ 595	$ 396
Lease assets obtained in exchange for new lease liabilities	32	10
Distribution reinvestment	26	15

4. INVENTORIES

Inventories consisted of the following:

	June 30, 2022	December 31, 2021
Natural gas, NGLs and refined products	$ 1,614	$ 1,259
Crude oil	167	328
Spare parts and other	435	427
Total inventories	$ 2,216	$ 2,014

Sunoco LP's fuel inventories are stated at the lower of cost or market using the last-in, first-out ("LIFO") method. As of June 30, 2022 and December 31, 2021, the carrying value of Sunoco LP's fuel inventory included lower of cost or market reserves of zero and $121 million, respectively. The fuel inventory replacement cost was $253 million higher than the fuel inventory balance as of June 30, 2022. For the three and six months ended June 30, 2022 and 2021, 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 June 30, 2022 and June 30, 2021, the Partnership's cost of products sold included favorable inventory adjustments of $1 million and $59 million, respectively, related to Sunoco LP's LIFO inventory. For the six months ended June 30, 2022 and 2021, the Partnership's cost of products sold included favorable inventory adjustments of $121 million and $159 million, respectively, related to Sunoco LP's LIFO inventory.

5. FAIR VALUE MEASURES

We have commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider options transacted through a clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. The valuation methodologies employed for our interest rate derivatives do not necessitate material judgment, and the inputs are observed from actively quoted public markets and therefore are categorized in Level 2. Level 3 inputs are unobservable. During the six months ended June 30, 2022, 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 June 30, 2022 and December 31, 2021 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2022	
	Fair Value Total	Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 11	$ 11	$ —
Swing Swaps IFERC	16	16	—
Fixed Swaps/Futures	51	51	—
Forward Physical Contracts	7	—	7
Power:			
Forwards	88	—	88
Futures	21	21	—
Options – Calls	1	1	—
NGLs – Forwards/Swaps	236	236	—
Refined Products – Futures	36	36	—
Crude – Forwards/Swaps	21	21	—
Total commodity derivatives	488	393	95
Other non-current assets	36	23	13
Total assets	$ 524	$ 416	$ 108
Liabilities:			
Interest rate derivatives	$ (144)	$ —	$ (144)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(5)	(5)	—
Swing Swaps IFERC	(3)	(3)	—
Fixed Swaps/Futures	(50)	(50)	—
Forward Physical Contracts	(4)	—	(4)
Power:			
Forwards	(67)	—	(67)
Futures	(30)	(30)	—
Options – Calls	(8)	(8)	—
NGLs – Forwards/Swaps	(204)	(204)	—
Refined Products – Futures	(3)	(3)	—
Crude – Forwards/Swaps	(7)	(7)	—
Total commodity derivatives	(381)	(310)	(71)
Total liabilities	$ (525)	$ (310)	$ (215)

	Fair Value Total	Fair Value Measurements at December 31, 2021	
		Level 1	Level 2
Assets:			
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	$ 7	$ 7	$ —
Swing Swaps IFERC	38	38	—
Fixed Swaps/Futures	26	26	—
Forward Physical Contracts	7	—	7
Power:			
Forwards	17	—	17
Futures	6	6	—
NGLs – Forwards/Swaps	152	152	—
Refined Products – Futures	3	3	—
Crude – Forwards/Swaps	16	16	—
Total commodity derivatives	272	248	24
Other non-current assets	39	26	13
Total assets	$ 311	$ 274	$ 37
Liabilities:			
Interest rate derivatives	$ (387)	$ —	$ (387)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(10)	(10)	—
Swing Swaps IFERC	(6)	(6)	—
Fixed Swaps/Futures	(9)	(9)	—
Forward Physical Contracts	(6)	—	(6)
Power:			
Forwards	(15)	—	(15)
Futures	(4)	(4)	—
NGLs – Forwards/Swaps	(140)	(140)	—
Refined Products – Futures	(18)	(18)	—
Crude – Forwards/Swaps	(3)	(3)	—
Total commodity derivatives	(211)	(190)	(21)
Total liabilities	$ (598)	$ (190)	$ (408)

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations as of June 30, 2022 were $46.29 billion and $48.65 billion, respectively, including a fair value of $543 million and a carrying amount of $543 million related to Energy Transfer Canada debt reflected in liabilities held for sale on the Partnership's consolidated balance sheet. As of December 31, 2021, the aggregate fair value and carrying amount of our consolidated debt obligations were $54.97 billion and $49.70 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 June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Net income	$ 1,622	$ 908	$ 3,109	$ 4,549
Less: Net income attributable to noncontrolling interests	284	269	489	610
Less: Net income attributable to redeemable noncontrolling interests	12	13	25	25
Net income, net of noncontrolling interests	1,326	626	2,595	3,914
Less: General Partner's interest in net income	1	1	2	4
Less: Preferred Unitholders' interest in net income	105	86	211	86
Common Unitholders' interest in net income	$ 1,220	$ 539	$ 2,382	$ 3,824
Basic Income per Common Unit:				
Weighted average common units	3,085.9	2,704.0	3,084.7	2,703.4
Basic income per common unit	$ 0.40	$ 0.20	$ 0.77	$ 1.41
Diluted Income per Common Unit:				
Common Unitholders' interest in net income	$ 1,220	$ 539	$ 2,382	$ 3,824
Dilutive effect of equity-based compensation of subsidiaries [(1)]	—	1	1	1
Diluted income attributable to Common Unitholders	$ 1,220	$ 538	$ 2,381	$ 3,823
Weighted average common units	3,085.9	2,704.0	3,084.7	2,703.4
Dilutive effect of unvested restricted unit awards [(1)]	19.8	13.8	19.5	12.1
Weighted average common units, assuming dilutive effect of unvested restricted unit awards	3,105.7	2,717.8	3,104.2	2,715.5
Diluted income per common unit	$ 0.39	$ 0.20	$ 0.77	$ 1.41

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

7. DEBT OBLIGATIONS

Senior Notes

In February 2022, the Partnership redeemed its $300 million aggregate principal amount of 4.65% Senior Notes due February 2022 using proceeds from its Five-Year Credit Facility (defined below).

In April 2022, Dakota Access redeemed its $650 million aggregate principal amount of 3.625% Senior Notes due April 2022 using proceeds from contributions made by the partners of Dakota Access. The Partnership indirectly owns 36.4% of the ownership interests in Dakota Access.

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 on April 11, 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 June 30, 2022, the Five-Year Credit Facility had $2.53 billion of outstanding borrowings, of which $1.03 billion consisted of commercial paper. The amount available for future borrowings was $2.44 billion, after accounting for outstanding letters of credit in the amount of $33 million. The weighted average interest rate on the total amount outstanding as of June 30, 2022 was 2.68%.

Sunoco LP Credit Facility

As of June 30, 2022, the Sunoco LP Credit Facility, as described in the Partnership's Form 10-K filed on February 18, 2022, had $869 million of outstanding borrowings and $6 million in standby letters of credit and, as amended in April 2022, matures in April 2027. The amount available for future borrowings at June 30, 2022 was $625 million. The weighted average interest rate on the total amount outstanding as of June 30, 2022 was 3.48%.

USAC Credit Facility

As of June 30, 2022, USAC had $559 million of outstanding borrowings and no outstanding letters of credit under the USAC Credit Facility, as described in the Partnership's Form 10-K filed on February 18, 2022. As of June 30, 2022, USAC had $1.0 billion of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $361 million. The weighted average interest rate on the total amount outstanding as of June 30, 2022 was 4.13%.

Energy Transfer Canada Credit Facilities

As of June 30, 2022, the Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility, both as described in the Partnership's Form 10-K filed on February 18, 2022, had outstanding borrowings of C$301 million and C$102 million, respectively (US$234 million and US$79 million, respectively, at the June 30, 2022 exchange rate). As of June 30, 2022, the KAPS Facility had outstanding borrowings of C$300 million (US$233 million at the June 30, 2022 exchange rate). The Energy Transfer Canada credit facilities were reflected in current liabilities held for sale on the Partnership's consolidated balance sheet as of June 30, 2022.

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 June 30, 2022. For the quarter ended June 30, 2022, our leverage ratio, as calculated pursuant to the covenant related to our revolving credit facility, was 3.45x.

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 June 30, 2022 included a balance of $477 million related to the USAC Series A preferred units and a balance of $16 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. As of December 31, 2021, redeemable noncontrolling interests included a balance of $477 million related to the USAC Series A preferred units, a balance of $15 million related to noncontrolling interest holders in one of the Partnership's consolidated subsidiaries that have the option to sell their interests to the Partnership, and a balance of $291 million related to Energy Transfer Canada preferred shares. The Energy Transfer Canada preferred shares were reflected in current liabilities held for sale as of June 30, 2022.

9. EQUITY

Energy Transfer Common Units

Changes in Energy Transfer common units during the six months ended June 30, 2022 were as follows:

	Number of Units
Number of common units at December 31, 2021	3,082.5
Common units issued under the distribution reinvestment plan	2.4
Common units vested under equity incentive plans and other	1.9
Number of common units at June 30, 2022	3,086.8

Energy Transfer Repurchase Program

During the six months ended June 30, 2022, Energy Transfer did not repurchase any of its common units under its current buyback program. As of June 30, 2022, $880 million remained available to repurchase under the current program.

Energy Transfer Distribution Reinvestment Program

During the six months ended June 30, 2022, distributions of $26 million were reinvested under the distribution reinvestment program. As of June 30, 2022, a total of 14 million Energy Transfer common units remained available to be issued under the existing registration statement in connection with the distribution reinvestment program.

Cash Distributions on Energy Transfer Common Units

Distributions declared and/or paid with respect to Energy Transfer common units subsequent to December 31, 2021 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2021	February 8, 2022	February 18, 2022	$ 0.1750
March 31, 2022	May 9, 2022	May 19, 2022	0.2000
June 30, 2022	August 8, 2022	August 19, 2022	0.2300

Energy Transfer Preferred Units

In connection with the merger of Energy Transfer, ETO, and certain of ETO's subsidiaries (the "Rollup Mergers") on April 1, 2021, as described in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2021, all of ETO's previously outstanding preferred units were converted to Energy Transfer Preferred Units with identical distribution and redemption rights.

As of June 30, 2022 and December 31, 2021, Energy Transfer's outstanding preferred units included 950,000 Series A Preferred Units, 550,000 Series B Preferred Units, 18,000,000 Series C Preferred Units, 17,800,000 Series D Preferred Units, 32,000,000 Series E Preferred Units, 500,000 Series F Preferred Units, 1,484,780 Series G Preferred Units and 900,000 Series H Preferred Units.

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

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

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

Cash Distributions on Energy Transfer Preferred Units

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

Period Ended	Record Date	Payment Date	Series A [(1)]	Series B [(1)]	Series C	Series D	Series E	Series F [(1)]	Series G [(1)]	Series H [(1)]
December 31, 2021	February 1, 2022	February 15, 2022	$ 31.250	$ 33.125	$ 0.4609	$ 0.4766	$ 0.475	$ —	$ —	$ —
March 31, 2022	May 2, 2022	May 16, 2022	—	—	0.4609	0.4766	0.475	33.750	35.625	32.500
June 30, 2022	August 1, 2022	August 15, 2022	31.250	33.125	0.4609	0.4766	0.475	—	—	—

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

Noncontrolling Interests

For the three months ended March 31, 2021, noncontrolling interests included the ETO preferred units, which were converted into Energy Transfer Preferred Units on April 1, 2021 in connection with the Rollup Mergers, as described in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2021.

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

Sunoco LP Cash Distributions

Distributions on Sunoco LP's common units declared and/or paid by Sunoco LP subsequent to December 31, 2021 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2021	February 8, 2022	February 18, 2022	$ 0.8255
March 31, 2022	May 9, 2022	May 19, 2022	0.8255
June 30, 2022	August 8, 2022	August 19, 2022	0.8255

USAC Cash Distributions

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2021 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2021	January 24, 2022	February 4, 2022	$ 0.525
March 31, 2022	April 25, 2022	May 6, 2022	0.525
June 30, 2022	July 25, 2022	August 5, 2022	0.525

USAC's Warrant Exercise

As of December 31, 2021, USAC had outstanding two tranches of warrants to purchase USAC common units (the "USAC Warrants"), which included USAC Warrants to purchase 5,000,000 common units with a strike price of $17.03 per unit and USAC Warrants to purchase 10,000,000 common units with a strike price of $19.59 per unit. On April 27, 2022, the tranche of warrants with the right to purchase 5,000,000 common units with a strike price of $17.03 per common unit was exercised in full by the holders. The exercise of the warrants was net settled by USAC for 534,308 of its common units.

As of June 30, 2022, the tranche of Warrants with the right to purchase 10,000,000 common units with a strike price of $19.59 per common unit was outstanding and may be exercised by the holders at any time before April 2, 2028.

Accumulated Other Comprehensive Income

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

	June 30, 2022	December 31, 2021
Available-for-sale securities	$ 10	$ 19
Foreign currency translation adjustment	(8)	13
Actuarial gains related to pensions and other postretirement benefits	12	5
Investments in unconsolidated affiliates, net	7	(11)
Total AOCI, net of tax	21	26
Amounts attributable to noncontrolling interest	8	(3)
Total AOCI included in partners' capital, net of tax	$ 29	$ 23

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Winter Storm Impacts

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

FERC Proceedings

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.

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 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 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, which are slated for briefing in late September 2022, with decisions unlikely until 2023. Energy Transfer and Rover intend to vigorously defend this claim.

Rover – FERC - Tuscarawas

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

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

Transwestern - FERC

On July 1, 2022, Transwestern filed a rate case pursuant to Section 4 of the Natural Gas Act. A procedural schedule for the case will be established in the third quarter, and a hearing is expected in 2023.

Other FERC Proceedings

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

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 is ongoing.

Commitments

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
ROW expense	$ 14	$ 9	$ 28	$ 15

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 June 30, 2022 and December 31, 2021, accruals of approximately $182 million and $144 million, respectively, were reflected on our consolidated balance sheets related to contingent losses 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 $600 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 sections below 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 below, 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 Dakota Access to be shut down and emptied of oil by August 5, 2020. Dakota Access and the USACE appealed to the United States Court of Appeals for the District of Columbia ("Court of Appeals") which granted an administrative stay of the District Court's July 6 order and ordered further briefing on whether to fully stay the July 6 order. On August 5, 2020, the Court of Appeals 1) granted a stay of the portion of the District Court order that required Dakota Access to shut the pipeline down and empty it of oil, 2) denied a motion to stay the March 25 order pending a decision on the merits by the Court of Appeals as to whether the USACE would be required to prepare an EIS, and 3) denied a motion to stay the District Court's order to vacate the easement during this appeal process. The August 5 order also states that the Court of Appeals expected the USACE to clarify its position with respect to whether USACE intended to allow the continued operation of the pipeline notwithstanding the vacatur of the easement and that the District Court may consider additional relief, if necessary.

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

The pipeline continues to operate pending completion of the EIS. Energy Transfer anticipates the draft EIS will be completed and published by the USACE in the Spring of 2023, subject to additional delays by the USACE. Currently, the release of the draft EIS is paused following the SRST's withdrawal as a cooperating agency on January 20, 2022. Energy Transfer cannot determine when or how future lawsuits will be resolved or the impact they may have on the Dakota Access pipelines; however, Energy Transfer expects after the law and complete record are fully considered, any such proceeding will be resolved in a manner that will allow the pipeline to continue to operate.

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

Mont Belvieu Incident

On June 26, 2016, a hydrocarbon storage well located on another operator's facility adjacent to Lone Star NGL 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 MTBE contamination of groundwater. The plaintiffs, state-level governmental entities, assert product liability, nuisance, trespass, negligence, violation of environmental laws, and/or deceptive business practices claims. The plaintiffs seek to recover compensatory damages, and in some cases also seek natural resource damages, injunctive relief, punitive damages, and attorneys' fees.

As of June 30, 2022, Sunoco Defendants are defendants in four cases, including one case initiated by the State of Maryland, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants ETO, ETP Holdco, and Sunoco Partners Marketing & Terminals L.P., now known as Energy Transfer Marketing & Terminals L.P. ("ETMT").

It is reasonably possible that a loss may be realized in the remaining cases; however, we are unable to estimate the possible loss or range of loss in excess of amounts accrued. An adverse determination with respect to one or more of the MTBE cases could have a significant impact on results of operations during the period in which any such adverse determination occurs, but such an adverse determination likely would not have a material adverse effect on the Partnership's consolidated financial position.

Litigation Filed By or Against Williams

In April and May 2016, The William Companies, Inc. ("Williams") filed two lawsuits (the "Williams Litigation") against Energy Transfer, LE GP, LLC, and, in one of the lawsuits, Energy Transfer Corp LP, ETE Corp GP, LLC, and Energy Transfer Equity GP, LLC (collectively, "Energy Transfer Defendants"), alleging that Energy Transfer Defendants breached their obligations under the Energy Transfer-Williams merger agreement (the "Merger Agreement"). In general, Williams alleges that Energy Transfer Defendants breached the Merger Agreement by (a) failing to use commercially reasonable efforts to obtain from Latham & Watkins LLP ("Latham") the delivery of a tax opinion concerning Section 721 of the

Internal Revenue Code ("721 Opinion"), (b) issuing the Partnership's Series A convertible preferred units (the "Issuance"), and (c) making allegedly untrue representations and warranties in the Merger Agreement.

After a two-day trial on June 20 and 21, 2016, the Court ruled in favor of Energy Transfer Defendants and issued a declaratory judgment that Energy Transfer could terminate the merger after June 28, 2016 because of Latham's inability to provide the required 721 Opinion. The Court did not reach a decision regarding Williams' claims related to the Issuance nor certain of the alleged untrue representations and warranties. On March 23, 2017, the Delaware Supreme Court affirmed the Court's ruling on the June 2016 trial. In September 2016, the parties filed amended pleadings. Williams filed an amended complaint seeking a $410 million termination fee (the "Termination Fee") based on the alleged breaches of the Merger Agreement listed above. Energy Transfer Defendants filed amended counterclaims and affirmative defenses, asserting that Williams materially breached the Merger Agreement by, among other things, (a) failing to use its reasonable best efforts to consummate the merger, (b) failing to provide material information to Energy Transfer for inclusion in the Form S-4 related to the merger, (c) failing to facilitate the financing of the merger, and (d) breaching the Merger Agreement's forum-selection clause.

Trial was held regarding the parties' amended claims on May 10-17, 2021, and on December 29, 2021, the Court ruled in favor of Williams and awarded it the Termination Fee plus certain fees and expenses, holding that the Issuance breached the Merger Agreement and that Williams had not materially breached the Merger Agreement, though the Court awarded sanctions against Williams due to its CEO's intentional spoliation of evidence.

On May 19, 2022, the Court held a hearing on Williams' motion for attorneys' fees and interest. The ruling has been taken under advisement. A final judgment has not yet been entered. Energy Transfer Defendants' deadline to file an appeal to the Delaware Supreme Court has not yet been set.

Rover - State of Ohio

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency (together "the Ohio EPA") filed suit against Rover and five other defendants seeking to recover civil penalties allegedly owed and certain injunctive relief related to permit compliance. The defendants filed several motions to dismiss, which were granted on all counts. The Ohio EPA appealed, and on December 9, 2019, the Fifth District Court of Appeals entered a unanimous judgment affirming the trial court. The Ohio EPA sought review from the Ohio Supreme Court, which the defendants opposed in briefs filed in February 2020. On April 22, 2020, the Ohio Supreme Court granted the Ohio EPA's request for review. 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 if 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, with Motions due August 1, 2022, Responses due October 4, 2022 and Replies due November 4, 2022.

Revolution

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

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

On February 2, 2022, the AG issued a press release related to the Revolution pipeline, and released a Grand Jury Presentment and filed a criminal complaint against ETC Northeast Pipeline, LLC in Magisterial District Court No. 12-2-02 in Dauphin County, Pennsylvania, with respect to nine misdemeanor charges related to various alleged violations of the Clean Streams Law associated with the construction of the Revolution pipeline. The Partnership will defend itself vigorously against these charges.

Chester County, Pennsylvania Investigation

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

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

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

On April 22, 2021, the Chester County DA filed a Complaint and Consent Decree in the Court of Common Pleas of Chester County, Pennsylvania constituting a settlement agreement between the Chester County DA and the Partnership. A status conference was held on May 10, 2021, and an Amended Consent Decree was filed on June 16, 2021, which was approved and entered by the Court on December 20, 2021. In accordance with the terms of the Amended Consent Decree, when the Mariner East 2/Mariner East 2X pipelines reached the point of mechanical completion in Chester County on March 23, 2022, the Amended Consent Decree terminated, which the Partnership communicated to the Chester County DA via letter on March 29, 2022.

Delaware County, Pennsylvania Investigation

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

Shareholder Litigation Regarding Pipeline Construction

Six purported unitholders of Energy Transfer 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 limited 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.); King v. LE GP, Case No. 3:20-cv-00719-X (N.D. Tex.); Inter-Marketing Group USA, Inc. v. LE GP, et at., Case No. 2022-0139-SG (Del. Ch.); and Elliot v. LE GP LLC, Case No. 3:22-cv-01527-B (N.D. Tex.). Another purported unitholder of Energy Transfer, Allegheny County Employees' Retirement System ("ACERS"), individually and on behalf of all others similarly situated, filed a suit under the federal securities laws purportedly on behalf of a class, against Energy Transfer and three of Energy Transfer's directors, Kelcy L. Warren, John W. McReynolds, and Thomas E. Long. See Allegheny County Emps.' Ret. Sys. v. Energy Transfer LP, Case No. 2:20-00200-GAM (E.D. Pa.). On June 15, 2020, ACERS filed an amended complaint and added as additional defendants Energy Transfer directors Marshall McCrea and Matthew 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. Fact discovery is ongoing. On July 8, 2022, the Court held a hearing on ACERS' motion for class certification.

On June 3, 2022, another purported unitholder of Energy Transfer, Mike Vega, filed suit, purportedly on behalf of a class, against Energy Transfer, Energy Transfer's CFO Brad Whitehurst, and Messrs. Warren, Long, and McCrea. See Vega v. Energy Transfer LP et al., Case No. 1:22-cv-4614 (S.D.N.Y.). Vega 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 the Rover pipeline in Ohio and Michigan.

On July 14, 2022, Gary Elliot, a purported unitholder of Energy Transfer, filed a derivative action against various past and current members of Energy Transfer's Board of Directors, LE GP, LLC, and Energy Transfer, as a nominal defendant, that asserts claims for breach of fiduciary duties, unjust enrichment, waste of corporate assets, abuse of control, and gross mismanagement related primarily to matters involving the construction of the Rover Pipeline. See Elliot v. LE GP, LLC, et al., Case No. 3:22-cv-1527 (N.D. Tex.).

The defendants cannot predict the outcome of these lawsuits or any lawsuits that might be filed subsequent to the date of this filing; nor can the defendants predict the amount of time and expense that will be required to resolve these lawsuits. However, the defendants believe that the claims are without merit and intend to vigorously contest them.

Cline Class Action

On July 7, 2017, Perry Cline filed a class action complaint in the Eastern District of Oklahoma against Sunoco (R&M), LLC (now known as Energy Transfer R&M) and 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 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 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. Sunoco 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. 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. However, ETMT intends to vigorously appeal the entirety of the Order, and has appealed the partial denial of the injunction and denial of the Motion to Modify to the 10th Circuit. Additionally, a Petition for Writ of Certiorari was filed with the United States Supreme Court on April 28, 2022, seeking review of the 10th Circuit's dismissal of ETMT's appeal. Cline's brief of opposition was filed on July 15, 2022.

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

On April 8, 2022, Energy Transfer LP ("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," and together with Culberson and Culberson Equity, "Defendants"). 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 Defendants asserting claims for declaratory judgment and breach of contract. Plaintiffs contend that Defendants 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 Defendants' put notice is void. Defendants have answered the lawsuit. 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 in Dallas County, Texas. On April 27, 2022, Defendants filed an application for a temporary restraining order, temporary injunction, and permanent injunction. 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. 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. 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 "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 AG seeks a refund to NEG's ratepayers for approximately $18 million in legal fees associated with SUG environmental response activities. The 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 AG contends only qualify for a lesser (i.e., 50 percent) level of recovery. Respondents maintain that, by tariff, these costs are recoverable through rates charged to NEG customers pursuant to the environmental remediation adjustment clause program. After the Respondents answered the complaint and filed a motion to dismiss in 2011, the Hearing Officer deferred decision on the motion to dismiss and issued a stay of discovery pending resolution of a discovery dispute, which it later lifted on June 24, 2013, permitting the case to resume. However, the 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 final procedural schedule on March 16, 2022. The parties are now actively engaged in discovery and the preparation of pre-filed testimony. Respondents submitted their pre-filed testimony on July 11, 2022. The AG's deadline to submit pre-filed testimony is September 13, 2022. Both sides will have an opportunity to issue discovery requests and submit rebuttal testimony. Subsequently, the parties will submit briefing to the DPU and may also request an evidentiary hearing. Respondents cannot predict the ultimate outcome of this regulatory proceeding, nor can they predict the amount of time and expense that will be required to resolve these claims; however, Respondents will vigorously defend themselves against the AG's claims.

Environmental Matters

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

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on our results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

Environmental Remediation

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

- certain of our interstate pipelines conduct soil and groundwater remediation related to contamination from past uses of polychlorinated biphenyls ("PCBs"). PCB assessments are ongoing and, in some cases, our subsidiaries could be contractually responsible for contamination caused by other parties.
- certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.
- legacy sites related to Sunoco, Inc. 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 June 30, 2022, the Partnership had been named as a PRP at approximately 34 identified or potentially identifiable "Superfund" sites under federal and/or comparable state law. The Partnership is usually one of a number of companies identified as a PRP at a site. The Partnership has reviewed the nature and extent of its involvement at each site and other relevant circumstances and, based upon the Partnership's purported nexus to the sites, believes that its potential liability associated with such sites will not be significant.

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

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

	June 30, 2022	December 31, 2021
Current	$ 50	$ 46
Non-current	231	247
Total environmental liabilities	$ 281	$ 293

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 six months ended June 30, 2022 and 2021, the Partnership recorded $6 million and $12 million, respectively, of expenditures related to environmental cleanup programs.

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

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

11. REVENUE

Disaggregation of Revenue

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

Contract Balances with Customers

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

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

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

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

	Contract Liabilities
Balance, December 31, 2021	$ 459
Additions	550
Revenue recognized	(441)
Other	(11)
Balance, June 30, 2022	$ 557
Balance, December 31, 2020	$ 309
Additions	434
Revenue recognized	(357)
Balance, June 30, 2021	$ 386

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

	June 30, 2022	December 31, 2021
Contract balances:		
Contract assets	$ 182	$ 157
Accounts receivable from contracts with customers	802	463

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 expected contract consideration 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 table below.

As of June 30, 2022, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations was $40.34 billion, of which $1.32 billion related to Energy Transfer Canada. The Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	Years Ending December 31,				
	2022 (remainder)	2023	2024	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of June 30, 2022	$ 3,634	$ 6,463	$ 5,567	$ 24,672	$ 40,336

12. DERIVATIVE ASSETS AND LIABILITIES

Commodity Price Risk

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

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

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

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

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

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

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

The following table details our outstanding commodity-related derivatives:

	June 30, 2022		December 31, 2021	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	1,023	2022-2023	585	2022-2023
Basis Swaps IFERC/NYMEX [(1)]	12,198	2022-2023	(66,665)	2022
Swing Swaps	543	2022	—	—
Power (Megawatt):				
Forwards	527,200	2023-2029	653,000	2023-2029
Futures	(289,086)	2022-2023	(604,920)	2022-2023
Options – Puts	119,200	2022-2023	(7,859)	2022
Options – Calls	(308,800)	2022-2023	(30,932)	2022
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	20,253	2022-2024	6,738	2022-2023
Swing Swaps IFERC	(39,755)	2022-2024	(106,333)	2022-2023
Fixed Swaps/Futures	(25,520)	2022-2023	(63,898)	2022-2023
Forward Physical Contracts	(7,498)	2022-2024	(5,950)	2023
NGLs (MBbls) – Forwards/Swaps	9,869	2022-2024	8,493	2022-2024
Crude (MBbls) – Forwards/Swaps	779	2022-2023	3,672	2022-2023
Refined Products (MBbls) – Futures	(2,748)	2022-2024	(3,349)	2022-2023
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(20,383)	2022	(40,533)	2022
Fixed Swaps/Futures	(20,383)	2022	(40,533)	2022
Hedged Item – Inventory	20,383	2022	40,533	2022

(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 utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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

		Notional Amount Outstanding	
Term	Type[(1)]	June 30, 2022	December 31, 2021
July 2022[(2)]	Forward-starting to pay an average fixed rate of 3.80% and receive a floating rate	$ —	$ 400
July 2023[(2)]	Forward-starting to pay an average fixed rate of 3.845% and receive a floating rate	400	200
July 2024[(2)]	Forward-starting to pay an average fixed rate of 3.512% and receive a floating rate	400	200

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

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

Credit Risk

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

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

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

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

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2022	December 31, 2021	June 30, 2022	December 31, 2021
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 56	$ 46	$ (26)	$ (3)
	56	46	(26)	(3)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	286	173	(253)	(156)
Commodity derivatives	146	53	(102)	(52)
Interest rate derivatives	—	—	(144)	(387)
	432	226	(499)	(595)
Total derivatives	$ 488	$ 272	$ (525)	$ (598)

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	June 30, 2022	December 31, 2021	June 30, 2022	December 31, 2021
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (144)	$ (387)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	146	53	(102)	(52)
Broker cleared derivative contracts	Other current assets (liabilities)	342	219	(279)	(159)
Total gross derivatives		488	272	(525)	(598)
Offsetting agreements:					
Collateral paid to OTC counterparties	Other current assets	—	—	—	—
Counterparty netting	Derivative assets (liabilities)	(89)	(43)	89	43
Counterparty netting	Other current assets (liabilities)	(210)	(150)	210	150
Total net derivatives		$ 189	$ 79	$ (226)	$ (405)

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 June 30,		Six Months Ended June 30,	
		2022	2021	2022	2021
Derivatives not designated as hedging instruments:					
Commodity derivatives – Trading	Cost of products sold	$ 11	$ (5)	$ 28	$ (2)
Commodity derivatives – Non-trading	Cost of products sold	(175)	(93)	(192)	(135)
Interest rate derivatives	Gains (losses) on interest rate derivatives	129	(123)	243	71
Total		$ (35)	$ (221)	$ 79	$ (66)

13. REPORTABLE SEGMENTS

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

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

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

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

We report Segment Adjusted EBITDA and consolidated Adjusted EBITDA as measures of segment performance. We define Segment Adjusted EBITDA and consolidated Adjusted EBITDA as total partnership earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Inventory adjustments that are excluded from the calculation of Adjusted EBITDA represent only the changes in lower of cost or market reserves on inventory that is carried at LIFO. These amounts are unrealized valuation adjustments applied to Sunoco LP’s fuel volumes remaining in inventory at the end of the period.

Segment Adjusted EBITDA and consolidated Adjusted EBITDA reflect amounts for unconsolidated affiliates based on the same recognition and measurement methods used to record equity in earnings of unconsolidated affiliates. Adjusted

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

The following tables present financial information by segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 1,994	$ 852	$ 3,469	$ 4,828
Intersegment revenues	209	97	366	1,021
	2,203	949	3,835	5,849
Interstate transportation and storage:				
Revenues from external customers	511	404	1,058	905
Intersegment revenues	19	3	38	27
	530	407	1,096	932
Midstream:				
Revenues from external customers	1,153	571	2,284	1,149
Intersegment revenues	3,897	1,628	6,691	3,722
	5,050	2,199	8,975	4,871
NGL and refined products transportation and services:				
Revenues from external customers	6,230	3,830	11,475	7,227
Intersegment revenues	1,327	692	2,359	1,285
	7,557	4,522	13,834	8,512
Crude oil transportation and services:				
Revenues from external customers	7,299	4,420	13,225	7,920
Intersegment revenues	1	—	1	—
	7,300	4,420	13,226	7,920
Investment in Sunoco LP:				
Revenues from external customers	7,793	4,385	13,190	7,854
Intersegment revenues	22	7	27	9
	7,815	4,392	13,217	7,863
Investment in USAC:				
Revenues from external customers	168	153	327	308
Intersegment revenues	4	3	8	6
	172	156	335	314
All other:				
Revenues from external customers	797	486	1,408	1,905
Intersegment revenues	165	90	269	183
	962	576	1,677	2,088
Eliminations	(5,644)	(2,520)	(9,759)	(6,253)
Total revenues	$ 25,945	$ 15,101	$ 46,436	$ 32,096

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Segment Adjusted EBITDA:				
Intrastate transportation and storage	$ 218	$ 224	$ 662	$ 3,037
Interstate transportation and storage	397	331	850	784
Midstream	903	477	1,710	765
NGL and refined products transportation and services	763	736	1,463	1,383
Crude oil transportation and services	562	484	1,155	994
Investment in Sunoco LP	214	201	405	358
Investment in USAC	106	100	204	200
All other	65	63	119	135
Adjusted EBITDA (consolidated)	3,228	2,616	6,568	7,656
Depreciation, depletion and amortization	(1,046)	(940)	(2,074)	(1,894)
Interest expense, net of interest capitalized	(578)	(566)	(1,137)	(1,155)
Impairment losses	—	(8)	(300)	(11)
Gains (losses) on interest rate derivatives	129	(123)	243	71
Non-cash compensation expense	(25)	(27)	(61)	(55)
Unrealized gains on commodity risk management activities	99	47	54	93
Inventory valuation adjustments (Sunoco LP)	1	59	121	159
Losses on extinguishments of debt	—	(1)	—	(8)
Adjusted EBITDA related to unconsolidated affiliates	(137)	(136)	(262)	(259)
Equity in earnings of unconsolidated affiliates	62	65	118	120
Other, net	(25)	4	(84)	(11)
Income before income tax expense	1,708	990	3,186	4,706
Income tax expense	(86)	(82)	(77)	(157)
Net income	$ 1,622	$ 908	$ 3,109	$ 4,549

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, 2021 filed with the SEC on February 18, 2022. 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, 2021 filed with the SEC on February 18, 2022. Additional information on forward-looking statements is discussed below in "Forward-Looking Statements."

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

RECENT DEVELOPMENTS

Woodford Express Acquisition

In August 2022, Energy Transfer entered into an agreement to acquire 100% of the membership interests in Woodford Express, LLC, a Mid-Continent gas gathering and processing system, for approximately $485 million in cash consideration. The system, which is located in the heart of the SCOOP play, has 450 MMcf/d of cryogenic gas processing and treating capacity and over 200 miles of gathering lines, which are connected to Energy Transfer's pipeline network. The transaction is expected to close by the end of the third quarter, subject to customary closing conditions including Hart-Scott-Rodino Act clearance.

Energy Transfer Canada Sale

In March 2022, the Partnership announced a definitive agreement to sell its 51% interest in Energy Transfer Canada. The sale is expected to result in cash proceeds to Energy Transfer of approximately C$340 million (US$264 million at the June 30, 2022 exchange rate), subject to certain purchase price adjustments. The transaction is expected to close by the third quarter of 2022.

Spindletop Assets Purchase

In March 2022, the Partnership purchased the membership interests in Caliche Coastal Holdings, LLC (subsequently renamed Energy Transfer Spindletop LLC), which owns an underground storage facility near Mont Belvieu, Texas, for approximately $325 million.

Sunoco LP Acquisition

On April 1, 2022, Sunoco LP completed the acquisition of a transmix processing and terminal facility in Huntington, Indiana for $264 million.

Quarterly Cash Distribution

In July 2022, Energy Transfer announced its quarterly distribution of $0.23 per unit ($0.92 annualized) on Energy Transfer common units for the quarter ended June 30, 2022.

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 recent rate making-related policy statements and rulemakings, the FERC or our shippers may challenge the cost-of-service rates we charge. The FERC's establishment of a just and reasonable rate is based on many components, including ROE and tax-related components, 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 ETC Tiger, Midcontinent Express and Fayetteville Express, have negotiated market rates that were agreed to by customers in connection with long-term contracts entered into to support the construction of the pipelines. Other systems, such as FGT, Transwestern and Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. The revenues we receive from natural gas transportation services we provide pursuant to cost-of-service based rates may decrease in the future as a result of changes to FERC policies, combined with the reduced corporate federal income tax rate established in the Tax Act. The extent of any revenue reduction related to our cost-of-service rates, if any, will depend on a detailed review of all of our cost-of-service components and the outcomes of any challenges to our rates by the FERC or our shippers.

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

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) a Policy Statement on the Certificate 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 are 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

The FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods, or PPI-FG. Many existing pipelines utilize the FERC liquids index to change transportation rates annually. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. The FERC's indexing methodology is subject to review every five years. In a December 2020 order, FERC determined that during the five-year period commencing July 1, 2021 and ending June 30, 2026, common carriers charging indexed rates will be permitted to adjust their indexed ceilings annually by PPI-FG plus 0.78 percent. 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, liquids pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by Producer Price Index minus 0.21%. FERC directed liquids pipelines to recompute their ceiling levels for July 1, 2021 through June 30, 2022 based on the new index level. Various pipelines have filed petitions for review of this decision with the U.S. Court of Appeals for the Fifth Circuit. 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 have sought rehearing of the January 20, 2022 order with FERC while others have appealed to the Fifth Circuit and DC Circuit. On May 6, 2022, FERC issued its order denying the rehearing requests. Certain shippers have now filed an appeal with the DC Circuit challenging the May 6th rehearing order.

Results of Operations

We report Segment Adjusted EBITDA and consolidated Adjusted EBITDA as measures of segment performance. We define Segment Adjusted EBITDA and consolidated Adjusted EBITDA as total partnership earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, inventory valuation adjustments, non-cash impairment charges, losses on extinguishments of debt and other non-operating income or expense items. Inventory adjustments that are excluded from the calculation of Adjusted EBITDA represent only the changes in lower of cost or market reserves on inventory that is carried at LIFO. These amounts are unrealized valuation adjustments applied to Sunoco LP's fuel volumes remaining in inventory at the end of the period.

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

Segment Adjusted EBITDA, as reported for each segment in the table below, is analyzed for each segment in the section titled "Segment Operating Results." Adjusted EBITDA is a non-GAAP measure used by industry analysts, investors, lenders and rating agencies to assess the financial performance and the operating results of the Partnership's fundamental business activities and should not be considered in isolation or as a substitution for net income, income from operations, cash flows from operating activities or other GAAP measures.

Consolidated Results

	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	Change	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	Change
Segment Adjusted EBITDA:						
Intrastate transportation and storage	$ 218	$ 224	$ (6)	$ 662	$ 3,037	$ (2,375)
Interstate transportation and storage	397	331	66	850	784	66
Midstream	903	477	426	1,710	765	945
NGL and refined products transportation and services	763	736	27	1,463	1,383	80
Crude oil transportation and services	562	484	78	1,155	994	161
Investment in Sunoco LP	214	201	13	405	358	47
Investment in USAC	106	100	6	204	200	4
All other	65	63	2	119	135	(16)
Adjusted EBITDA (consolidated)	3,228	2,616	612	6,568	7,656	(1,088)
Depreciation, depletion and amortization	(1,046)	(940)	(106)	(2,074)	(1,894)	(180)
Interest expense, net of interest capitalized	(578)	(566)	(12)	(1,137)	(1,155)	18
Impairment losses	—	(8)	8	(300)	(11)	(289)
Gains (losses) on interest rate derivatives	129	(123)	252	243	71	172
Non-cash compensation expense	(25)	(27)	2	(61)	(55)	(6)
Unrealized gains on commodity risk management activities	99	47	52	54	93	(39)
Inventory valuation adjustments (Sunoco LP)	1	59	(58)	121	159	(38)
Losses on extinguishments of debt	—	(1)	1	—	(8)	8
Adjusted EBITDA related to unconsolidated affiliates	(137)	(136)	(1)	(262)	(259)	(3)
Equity in earnings of unconsolidated affiliates	62	65	(3)	118	120	(2)
Other, net	(25)	4	(29)	(84)	(11)	(73)
Income before income tax expense	1,708	990	718	3,186	4,706	(1,520)
Income tax expense	(86)	(82)	(4)	(77)	(157)	80
Net income	$ 1,622	$ 908	$ 714	$ 3,109	$ 4,549	$ (1,440)

Adjusted EBITDA (consolidated). For the three months ended June 30, 2022 compared to the same period last year, Adjusted EBITDA increased 23% primarily due to the impacts of the recent Enable Acquisition, which contributed $334 million of margin in our midstream segment and $110 million of margin in our interstate transportation and storage segment. In addition, the increase in Adjusted EBITDA also reflected a favorable impact of $137 million from natural gas and NGL prices in our midstream segment.

For the six months ended June 30, 2022 compared to the same period last year, Adjusted EBITDA decreased 14% primarily due to the impacts of Winter Storm Uri in February 2021. The most significant impacts were in our intrastate transportation and storage segment, where Segment Adjusted EBITDA decreased by $2.38 billion primarily due to a $1.51 billion decrease in realized storage margin and an $844 million decrease in realized natural gas sales, both of which were primarily due to the impact of Winter Storm Uri in the prior period. These decreases were partially offset by favorable results in multiple segments, the most significant of which were in our midstream segment, where Segment Adjusted EBITDA increased by $945 million primarily due to favorable natural gas and NGL prices and the impact of the recent Enable Acquisition.

Additional information on changes impacting Adjusted EBITDA for the three and six months ended June 30, 2022 compared to the same periods last year, including other impacts from Winter Storm Uri and other non-storm-related factors, is available below in “Segment Operating Results.”

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased for the three and six months ended June 30, 2022 compared to the same period last year primarily due to incremental depreciation and amortization related to the Enable assets acquired in December 2021 and assets recently placed in service.

Interest Expense, net. Interest expense, net of interest capitalized, increased for the three months ended June 30, 2022 compared to the same period last year, primarily due to the following:

- the Partnership's interest expense increased by $9 million due to an increase in average long-term debt resulting from the Enable Acquisition as well as higher interest rates on floating rate debt.
- Sunoco LP's interest expense increased by $2 million due to an increase in average total long-term debt and an increase in the weighted average interest rate on long-term debt.
- USAC's interest expense increased by $1 million due to higher weighted-average interest rates and increased borrowings under its credit agreement, partially offset by a decrease in amortization of debt issuance costs related to the amendment and restatement of its credit agreement since the prior period.

Interest expense, net of interest capitalized, decreased for the six months ended June 30, 2022 compared to the same period last year, primarily due to the following:

- the Partnership's interest expense decreased by $20 million due to lower non-cash interest expense in the current period, partially offset by an increase in average long-term debt resulting from the Enable Acquisition as well as higher interest rates on floating rate debt.
- Sunoco LP's interest expense increased by $2 million due to an increase in average total long-term debt and an increase in the weighted average interest rate on long-term debt.

Impairment Losses. For the six months ended June 30, 2022, impairment losses included a $300 million impairment of Energy Transfer Canada's assets based on the anticipated proceeds from the expected sale of those assets.

For the three months ended June 30, 2021 impairment losses reflected $2 million recognized by USAC related to its compression equipment as a result of its evaluations of the future deployment of its idle fleet under current market conditions and a $6 million impairment of intangible assets related to customer contracts within the Partnership's crude operations. For the six months ended June 30, 2021, impairment losses included an additional $3 million recognized by USAC during the first quarter of 2021 related to its compression equipment.

Gains (Losses) on Interest Rate Derivatives. Gains and losses on interest rate derivatives during the three and six months ended June 30, 2022 resulted from changes in forward interest rates, which caused our forward-starting swaps to change in value.

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

Inventory Valuation Adjustments. Inventory valuation adjustments represent changes in lower of cost or market using the last-in, first-out method on Sunoco LP's inventory. These amounts are unrealized valuation adjustments applied to fuel volumes remaining in inventory at the end of the period. For the three months ended June 30, 2022 and June 30, 2021, an increase in fuel prices reduced lower of cost or market reserve requirements by $1 million and $59 million, respectively, resulting in favorable impacts to net income. For the six months ended June 30, 2022 and June 30, 2021, an increase in fuel prices reduced lower of cost or market reserve requirements by $121 million and $159 million, respectively, resulting in favorable impacts to net income.

Losses on Extinguishments of Debt. For the three months ended June 30, 2021, the loss on extinguishment of debt was related to the Partnership's partial repayment of its Term Loan. For the six months ended June 30, 2021, the losses on extinguishments of debt also included Sunoco LP's January 2021 repurchase of the remainder of its 2023 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" below.

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

Income Tax Expense. For the three months ended June 30, 2022 compared to the same period last year, income tax expense increased due to higher earnings from the Partnership's consolidated corporate subsidiaries in the current period. For the six months ended June 30, 2022 compared to the same period last year, income tax expense decreased due to lower earnings from the Partnership's consolidated corporate subsidiaries in the current period.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	Change	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	Change
Equity in earnings (losses) of unconsolidated affiliates:						
Citrus	$ 39	$ 42	$ (3)	$ 73	$ 79	$ (6)
MEP	(2)	(4)	2	(6)	(7)	1
White Cliffs	1	1	—	1	1	—
Explorer	5	8	(3)	9	11	(2)
Other	19	18	1	41	36	5
Total equity in earnings of unconsolidated affiliates	$ 62	$ 65	$ (3)	$ 118	$ 120	$ (2)
Adjusted EBITDA related to unconsolidated affiliates[(1)]:						
Citrus	$ 82	$ 85	$ (3)	$ 159	$ 164	$ (5)
MEP	6	5	1	11	10	1
White Cliffs	5	5	—	10	10	—
Explorer	9	13	(4)	16	19	(3)
Other	35	28	7	66	56	10
Total Adjusted EBITDA related to unconsolidated affiliates	$ 137	$ 136	$ 1	$ 262	$ 259	$ 3
Distributions received from unconsolidated affiliates:						
Citrus	$ 21	$ 29	$ (8)	$ 81	$ 85	$ (4)
MEP	6	4	2	10	8	2
White Cliffs	5	5	—	10	20	(10)
Explorer	9	10	(1)	14	14	—
Other	23	16	7	39	37	2
Total distributions received from unconsolidated affiliates	$ 64	$ 64	$ —	$ 154	$ 164	$ (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 tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

- *Segment margin, operating expenses,* and *selling, general and administrative expenses*. These amounts represent the amounts included in our consolidated financial statements that are attributable to each segment.
- *Unrealized gains or losses on commodity risk management activities and inventory valuation adjustments*. These are the unrealized amounts that are included in cost of products sold to calculate segment margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.

- *Non-cash compensation expense*. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative expenses. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.
- *Adjusted EBITDA related to unconsolidated affiliates*. Adjusted EBITDA related to unconsolidated affiliates excludes the same items with respect to the unconsolidated affiliate as those excluded from the calculation of Segment Adjusted EBITDA, such as interest, taxes, depreciation, depletion, amortization and other non-cash items. Although these amounts are excluded from Adjusted EBITDA related to unconsolidated affiliates, such exclusion should not be understood to imply that we have control over the operations and resulting revenues and expenses of such affiliates. We do not control our unconsolidated affiliates; therefore, we do not control the earnings or cash flows of such affiliates.

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 sections below include information on the components of segment margin by sales type, which components are included in order to provide additional disaggregated information to facilitate the analysis of segment margin and Segment Adjusted EBITDA. For example, these components include transportation margin, storage margin and other margin. These components of segment margin are calculated consistent with the calculation of segment margin; therefore, these components also exclude charges for depreciation, depletion and amortization.

Winter Storm Uri, which occurred in February 2021, resulted in one-time impacts to the Partnership's Adjusted EBITDA and also affected the results of operations in certain segments, as discussed in segment analysis. The recognition of the impacts of Winter Storm Uri during the three months ended March 31, 2021 required management to make certain estimates and assumptions, including estimates of expected credit losses and assumptions related to the resolution of disputes with counterparties with respect to certain purchases and sales of natural gas. The ultimate realization of credit losses and the resolution of disputed purchases and sales of natural gas could materially impact the Partnership's financial condition and results of operations in future periods.

Intrastate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Natural gas transported (BBtu/d)	14,834	12,195	2,639	14,406	11,710	2,696
Withdrawals from storage natural gas inventory (BBtu)	—	10,643	(10,643)	21,858	29,688	(7,830)
Revenues	$ 2,203	$ 949	$ 1,254	$ 3,835	$ 5,849	$ (2,014)
Cost of products sold	1,843	664	1,179	3,014	2,658	356
Segment margin	360	285	75	821	3,191	(2,370)
Unrealized (gains) losses on commodity risk management activities	(41)	(5)	(36)	5	(17)	22
Operating expenses, excluding non-cash compensation expense	(95)	(55)	(40)	(158)	(135)	(23)
Selling, general and administrative expenses, excluding non-cash compensation expense	(13)	(9)	(4)	(25)	(17)	(8)
Adjusted EBITDA related to unconsolidated affiliates	7	7	—	13	13	—
Other	—	1	(1)	6	2	4
Segment Adjusted EBITDA	$ 218	$ 224	$ (6)	$ 662	$ 3,037	$ (2,375)

Volumes. For the three months ended June 30, 2022 compared to the same period last year, transported volumes increased primarily due to the acquisition of the Enable Oklahoma Intrastate Transmission system, as well as increased production in the Permian and Haynesville.

For the six months ended June 30, 2022 compared to the same period last year, transported volumes increased primarily due to the acquisition of the Enable Oklahoma Intrastate Transmission system, as well as increased production in the Permian and Haynesville.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Transportation fees	$ 196	$ 200	$ (4)	$ 411	$ 380	$ 31
Natural gas sales and other (excluding unrealized gains and losses)	75	57	18	284	1,128	(844)
Retained fuel revenues (excluding unrealized gains and losses)	59	23	36	91	116	(25)
Storage margin (excluding unrealized gains and losses and fair value inventory adjustments)	(11)	—	(11)	40	1,550	(1,510)
Unrealized gains (losses) on commodity risk management activities and fair value inventory adjustments	41	5	36	(5)	17	(22)
Total segment margin	$ 360	$ 285	$ 75	$ 821	$ 3,191	$ (2,370)

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment decreased due to the net impacts of the following:

- an increase of $40 million in operating expenses primarily due to an increase of $19 million in cost of fuel consumption, an increase of $10 million in additional expenses from the Enable assets, an increase of $7 million in utilities expenses, and an increase of $2 million in ad valorem taxes;
- an increase of $4 million in selling, general and administrative expenses primarily due to the addition of Enable;
- a decrease of $4 million in transportation fees primarily due to revenues related to Winter Storm Uri in the prior period, partially offset by fees from the Enable Oklahoma Intrastate Transmission System; and
- a decrease of $11 million in storage margin primarily due to lower storage optimization; partially offset by
- an increase of $36 million in retained fuel revenues related to higher natural gas prices; and
- an increase of $18 million in realized natural gas sales and other primarily due to the recognition in the current period of certain contingent amounts related to Winter Storm Uri.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $1.51 billion in realized storage margin primarily due to higher physical storage margin from withdrawals during Winter Storm Uri in the prior period;
- a decrease of $844 million in realized natural gas sales and other primarily due to natural gas sales at prevailing market prices during Winter Storm Uri in the prior period;
- a decrease of $25 million in retained fuel revenues related to natural gas prices, including the impact from Winter Storm Uri in the prior period;
- an increase of $23 million in operating expenses primarily due to an increase of $16 million from additional expenses from the Enable assets, an increase of $4 million in ad valorem taxes, and an increase of $3 million in cost of fuel consumption from higher gas prices; and
- an increase of $8 million in selling, general and administrative expenses primarily due to the addition of Enable and higher corporate expenses; partially offset by
- an increase of $30 million in transportation fees primarily due to fees on the recently acquired Enable Oklahoma Intrastate Transmission system, partially offset by fees related to Winter Storm Uri in the prior period.

Interstate Transportation and Storage

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Natural gas transported (BBtu/d)	13,833	9,735	4,098	14,462	9,695	4,767
Natural gas sold (BBtu/d)	21	18	3	31	20	11
Revenues	$ 530	$ 407	$ 123	$ 1,096	$ 932	$ 164
Cost of products sold	2	—	2	21	—	21
Segment margin	528	407	121	1,075	932	143
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(200)	(143)	(57)	(371)	(277)	(94)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(32)	(21)	(11)	(63)	(42)	(21)
Adjusted EBITDA related to unconsolidated affiliates	99	89	10	187	174	13
Other	2	(1)	3	22	(3)	25
Segment Adjusted EBITDA	$ 397	$ 331	$ 66	$ 850	$ 784	$ 66

Volumes. For the three and six months ended June 30, 2022 compared to the same periods last year, transported volumes increased primarily due to the impact of the Enable Acquisition, higher utilization on our Tiger system due to increased production in the Haynesville Shale, and higher volumes on our Transwestern system and on our Panhandle system due to increased demand.

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $121 million in segment margin primarily due to a $110 million increase due to the impact of the Enable Acquisition, a $21 million increase in transportation revenue from our Transwestern, Tiger, Rover and Trunkline Gas systems due to higher contracted volumes and higher rates, and a $6 million increase due to higher volumes and higher rates on operational gas sales on Transwestern. These increases were partially offset by an $11 million decrease resulting from shipper contract expirations on our Tiger system and a $5 million decrease on our Panhandle system due to less capacity sold; and
- an increase of $10 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to the Enable Acquisition in December 2021; partially offset by
- an increase of $57 million in operating expenses primarily due to a $40 million increase from the impact of the Enable Acquisition, an $11 million increase resulting from the revaluation of system gas, a $3 million increase in maintenance project costs and a $2 million increase in ad valorem taxes; and
- an increase of $11 million in selling, general and administrative expenses primarily due to the impact of the Enable Acquisition.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment increased due to the net impacts of the following:

- an increase of $143 million in segment margin primarily due to a $218 million increase from the Enable Acquisition and a $45 million increase in transportation revenue from our Transwestern, Tiger, Rover and Trunkline Gas systems due to higher contracted volumes and higher rates. These increases were partially offset by a $77 million decrease primarily due to Winter Storm Uri related operational gas sale gains recorded in the prior period, a $31 million decrease resulting from contract expirations and a shipper bankruptcy on our Tiger system and a $14 million decrease due to less capacity sold on our Panhandle system;
- an increase of $13 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to the Enable Acquisition in December 2021; and
- an increase of $25 million in other primarily due to the realization in the current period of certain amounts related to a shipper bankruptcy that occurred in a prior period; partially offset by

- an increase of $94 million in operating expenses primarily due to a $73 million increase from the impact of the Enable Acquisition, a $9 million increase resulting from the revaluation of system gas and a $12 million increase in maintenance project costs and materials; and
- an increase of $21 million in selling, general and administrative expenses primarily due to the impact of the Enable Acquisition.

Midstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Gathered volumes (BBtu/d)	18,332	13,112	5,220	17,835	12,571	5,264
NGLs produced (MBbls/d)	813	665	148	786	600	186
Equity NGLs (MBbls/d)	46	38	8	44	34	10
Revenues	$ 5,050	$ 2,199	$ 2,851	$ 8,975	$ 4,871	$ 4,104
Cost of products sold	3,855	1,509	2,346	6,740	3,711	3,029
Segment margin	1,195	690	505	2,235	1,160	1,075
Unrealized losses on commodity risk management activities	2	—	2	—	—	—
Operating expenses, excluding non-cash compensation expense	(259)	(196)	(63)	(493)	(360)	(133)
Selling, general and administrative expenses, excluding non-cash compensation expense	(41)	(27)	(14)	(85)	(52)	(33)
Adjusted EBITDA related to unconsolidated affiliates	6	8	(2)	15	15	—
Other	—	2	(2)	38	2	36
Segment Adjusted EBITDA	$ 903	$ 477	$ 426	$ 1,710	$ 765	$ 945

Volumes. Gathered volumes and NGL production increased during the three and six months ended June 30, 2022 compared to the same periods last year due to increased production in the South Texas and Northeast regions, additional gathering capacity from the Permian Bridge, and new volumes from the Enable Acquisition in December 2021.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Gathering and processing fee-based revenues	$ 745	$ 522	$ 223	$ 1,442	$ 1,020	$ 422
Non-fee-based contracts and processing	452	168	284	793	140	653
Unrealized losses on commodity risk management activities	(2)	—	(2)	—	—	—
Total segment margin	$ 1,195	$ 690	$ 505	$ 2,235	$ 1,160	$ 1,075

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $137 million in non-fee-based margin due to favorable natural gas prices of $61 million and NGL prices of $76 million;
- an increase of $146 million in non-fee-based margin due to the Enable Acquisition in December 2021, as well as increased production in the Permian and South Texas regions; and
- an increase of $223 million in fee-based margin due to the Enable Acquisition in December 2021, as well as increased production in the Permian and South Texas regions; partially offset by

- an increase of $63 million in operating expenses due to $57 million in incremental operating expenses related to the Enable assets acquired in December 2021 and a $6 million increase in materials pricing and repairs in the South Texas and Permian regions; and
- an increase of $14 million in selling, general and administrative expenses due to an $11 million increase from the impact of the Enable Acquisition and a $3 million increase in insurance and legal fees.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $243 million in non-fee-based margin due to favorable natural gas prices of $95 million and NGL prices of $148 million;
- an increase of $267 million in non-fee-based margin due to the Enable Acquisition in December 2021, as well as increased production in the Permian, Northeast and South Texas regions;
- an increase of $143 million in non-fee-based margin due to the impacts of Winter Storm Uri in the prior period; and
- an increase of $422 million in fee-based margin due to the Enable Acquisition in December 2021, as well as increased production in the Permian and South Texas regions; partially offset by
- an increase of $133 million in operating expenses due to $99 million in incremental operating expenses related to the Enable assets acquired in December 2021, a $19 million increase in materials pricing and repairs in the South Texas and Permian regions, a $7 million increase in fuel prices, a $4 million increase in ad valorem taxes and a $4 million increase in right-of-way licensing fees; and
- an increase of $33 million in selling, general and administrative expenses due to a $26 million increase from the impact of the Enable Acquisition and a $5 million increase in legal fees.

NGL and Refined Products Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
NGL transportation volumes (MBbls/d)	1,912	1,748	164	1,833	1,625	208
Refined products transportation volumes (MBbls/d)	526	510	16	511	486	25
NGL and refined products terminal volumes (MBbls/d)	1,311	1,186	125	1,246	1,115	131
NGL fractionation volumes (MBbls/d)	938	833	105	872	780	92
Revenues	$ 7,557	$ 4,522	$ 3,035	$ 13,834	$ 8,512	$ 5,322
Cost of products sold	6,521	3,547	2,974	11,877	6,688	5,189
Segment margin	1,036	975	61	1,957	1,824	133
Unrealized gains on commodity risk management activities	(27)	(46)	19	(32)	(69)	37
Operating expenses, excluding non-cash compensation expense	(241)	(194)	(47)	(443)	(366)	(77)
Selling, general and administrative expenses, excluding non-cash compensation expense	(28)	(27)	(1)	(63)	(55)	(8)
Adjusted EBITDA related to unconsolidated affiliates	23	28	(5)	44	49	(5)
Segment Adjusted EBITDA	$ 763	$ 736	$ 27	$ 1,463	$ 1,383	$ 80

Volumes. For the three and six months ended June 30, 2022 compared to the same period last year, NGL transportation volumes increased primarily due to higher volumes from the Permian and Eagle Ford regions and the ramp-up in volumes on our propane and ethane export pipelines into our Nederland Terminal.

Refined products transportation volumes increased for the three and six months ended June 30, 2022 compared to the same period last year due to recovery from COVID-19 related demand reduction in the prior period.

NGL and refined products terminal volumes increased for the three and six months ended June 30, 2022 compared to the same period last year primarily due to the ramp-up in volumes on our propane and ethane export pipelines and refined product demand recovery.

Average fractionated volumes at our Mont Belvieu, Texas fractionation facility increased for the three and six months ended June 30, 2022 compared to the same periods last year due to increased production to our system, primarily from the Permian and Eagle Ford regions.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Transportation margin	$ 520	$ 489	$ 31	$ 999	$ 981	$ 18
Fractionators and refinery services margin	215	183	32	400	328	72
Terminal services margin	191	163	28	342	304	38
Storage margin	67	70	(3)	139	137	2
Marketing margin	16	24	(8)	45	5	40
Unrealized gains on commodity risk management activities	27	46	(19)	32	69	(37)
Total segment margin	$ 1,036	$ 975	$ 61	$ 1,957	$ 1,824	$ 133

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $32 million in fractionators and refinery services margin primarily due to a $46 million increase from higher volumes and increased utilization of our ethane optimization strategy in 2022. This increase was partially offset by a $9 million decrease from a less favorable pricing environment impacting our refinery services business and a $7 million intrasegment charge, which is fully offset in our transportation margin;
- an increase of $31 million in transportation margin primarily due to a $32 million increase resulting from higher y-grade throughput on our Texas pipeline system, a $7 million intrasegment charge, which is offset in our fractionators margin, a $6 million increase from higher exported volumes feeding into our Nederland Terminal, and a $5 million increase from higher throughput on our Mariner East pipeline system. These increases were partially offset by an $11 million decrease from lower throughput on our Mariner West pipeline due to the timing of customer facility maintenance and intrasegment charges of $9 million, which are fully offset within our marketing margin; and
- an increase of $28 million in terminal services margin primarily due to an $18 million increase from higher export volumes loaded at our Nederland Terminal and an $8 million increase from higher throughput at our Marcus Hook Terminal; partially offset by
- an increase of $47 million in operating expenses primarily due to a $35 million increase in gas and power utility costs, an $8 million increase from maintenance project costs and a $3 million increase in ad valorem taxes;
- a decrease of $8 million in marketing margin primarily due to a $39 million decrease due to lower gains from the optimization of NGL component products from our Gulf Coast NGL activities. This decrease was partially offset by a $20 million increase from our northeast blending and optimization activities and intrasegment charges of $9 million, which are fully offset within our transportation margin; and
- a decrease of $5 million in Adjusted EBITDA related to unconsolidated affiliates due to a $4 million decrease from lower volumes on the Explorer pipeline and a $2 million decrease from lower volumes on the White Cliffs pipeline.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our NGL and refined products transportation and services segment increased due to the net impacts of the following:

- an increase of $72 million in fractionators and refinery services margin primarily due to a $75 million increase from higher volumes and increased utilization of our ethane optimization strategy in 2022 and a $9 million intrasegment charge , which is fully offset in our transportation margin. These increases were partially offset by a $12 million decrease from a less favorable pricing environment impacting our refinery services business;

- an increase of $40 million in marketing margin due to intrasegment charges of $53 million, which are fully offset within our transportation margin, and a $47 million increase from our northeast blending and optimization activities. These increases were partially offset by a $59 million decrease due to lower gains from the optimization of NGL component products from our Gulf Coast NGL activities;
- an increase of $38 million in terminal services margin primarily due to a $25 million increase from higher export volumes loaded at our Nederland Terminal and an $11 million increase from higher throughput at our Marcus Hook Terminal; and
- an increase of $18 million in transportation margin primarily due to a $76 million increase resulting from higher y-grade throughput on our Texas pipeline system and a $14 million increase from higher exported volumes feeding into our Nederland Terminal. These increases were partially offset by intrasegment charges of $53 million, which are fully offset within our marketing margin, a $15 million decrease resulting from lower throughput on our Mariner West pipeline due to customer maintenance, and a $9 million intrasegment charge related to cavern withdrawals, which is offset in our fractionators margin; partially offset by
- an increase of $77 million in operating expenses due to a $54 million increase in gas and power utility costs, a $9 million increase in ad valorem taxes, a $7 million increase from maintenance project costs, a $3 million increase in office expenses, and a $3 million increase in employee costs;
- an increase of $8 million in selling, general and administrative expenses primarily due to a $5 million increase in insurance, information technology, legal and advertising costs and a $2 million increase in employee related costs; and
- a decrease of $5 million in Adjusted EBITDA related to unconsolidated affiliates due to a $3 million decrease from lower volumes on the Explorer pipeline and a $3 million decrease from lower volumes on the White Cliffs pipeline.

Crude Oil Transportation and Services

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Crude transportation volumes (MBbls/d)	4,318	3,987	331	4,267	3,763	504
Crude terminal volumes (MBbls/d)	3,056	2,594	462	2,911	2,477	434
Revenues	$ 7,300	$ 4,420	$ 2,880	$ 13,226	$ 7,920	$ 5,306
Cost of products sold	6,541	3,764	2,777	11,720	6,602	5,118
Segment margin	759	656	103	1,506	1,318	188
Unrealized (gains) losses on commodity risk management activities	(17)	3	(20)	(6)	(2)	(4)
Operating expenses, excluding non-cash compensation expense	(154)	(150)	(4)	(291)	(272)	(19)
Selling, general and administrative expenses, excluding non-cash compensation expense	(27)	(28)	1	(57)	(58)	1
Adjusted EBITDA related to unconsolidated affiliates	1	3	(2)	2	8	(6)
Other	—	—	—	1	—	1
Segment Adjusted EBITDA	$ 562	$ 484	$ 78	$ 1,155	$ 994	$ 161

Volumes. For the three and six months ended June 30, 2022 compared to the same periods last year, crude transportation volumes were higher on our Texas pipeline system and Bakken Pipeline, driven by continued recovery in crude oil production in these regions as a result of higher crude oil prices and refinery demand. Additionally, volumes benefited from assets acquired in the Enable Acquisition as well as new assets placed into service. Crude terminal volumes were higher due to increased refinery demand and increased export activity at our Gulf Coast terminals.

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $83 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $58 million increase due to higher volumes on our Bakken Pipeline, a $20 million increase from assets acquired in the Enable Acquisition, and an $11 million increase in throughput at our Gulf Coast terminals due to stronger refinery and export demand, partially offset by a $3 million decrease due to lower volumes on our Bayou Bridge pipeline; partially offset by
- an increase of $4 million in operating expenses primarily due to higher volume-driven expenses, and expenses related to assets acquired in the Enable Acquisition; and
- a decrease of $2 million in Adjusted EBITDA related to unconsolidated affiliates due to the consolidation of certain operations that were previously reflected as unconsolidated affiliates.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our crude oil transportation and services segment increased due to the net impacts of the following:

- an increase of $184 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $140 million increase due to higher volumes on our Bakken Pipeline, a $35 million increase related to assets acquired in the Enable Acquisition, a $16 million increase in throughput at our Gulf Coast terminals due to higher refinery and export demand, a $12 million increase from our Texas crude pipeline system due to higher volumes transported, and a $4 million increase due to higher volumes on our Bayou Bridge pipeline, partially offset by a $19 million decrease from our crude oil acquisition and marketing business due to less favorable pricing conditions impacting our trading operations; partially offset by
- an increase of $19 million in operating expenses primarily due to higher volume-driven expenses and expenses related to assets acquired in the Enable Acquisition; and
- a decrease of $6 million in Adjusted EBITDA related to unconsolidated affiliates due to the consolidation of certain operations that were previously reflected as unconsolidated affiliates.

Investment in Sunoco LP

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Revenues	$ 7,815	$ 4,392	$ 3,423	$ 13,217	$ 7,863	$ 5,354
Cost of products sold	7,470	4,039	3,431	12,442	7,159	5,283
Segment margin	345	353	(8)	775	704	71
Unrealized gains on commodity risk management activities	(11)	(2)	(9)	(20)	(7)	(13)
Operating expenses, excluding non-cash compensation expense	(98)	(75)	(23)	(195)	(151)	(44)
Selling, general and administrative expenses, excluding non-cash compensation expense	(27)	(24)	(3)	(49)	(44)	(5)
Adjusted EBITDA related to unconsolidated affiliates	3	2	1	5	4	1
Inventory valuation adjustments	(1)	(59)	58	(121)	(159)	38
Other	3	6	(3)	10	11	(1)
Segment Adjusted EBITDA	$ 214	$ 201	$ 13	$ 405	$ 358	$ 47

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

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment increased due to the net impacts of the following:

- an increase in the gross profit on motor fuel sales of $15 million primarily due to a 9.6% increase in gross profit per gallon sold and a 2.7% increase in gallons sold; and

- an increase in non-motor fuel gross profit of $24 million primarily due to the 2021 fourth quarter acquisition of refined product terminals, as well as increased credit card transactions and merchandise gross profit; partially offset by
- an increase in operating expenses and selling, general and administrative expenses of $26 million primarily due to the recent acquisitions of refined product terminals and a transmix processing and terminal facility, higher employee costs and credit card processing fees.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our investment in Sunoco LP segment increased due to the net impacts of the following:

- an increase in the gross profit on motor fuel sales of $51 million primarily due to a 14.1% increase in gross profit per gallon sold and a 1.8% increase in gallons sold; and
- an increase in non-motor fuel gross profit of $45 million primarily due to the 2021 fourth quarter acquisition of refined product terminals, as well as increased credit card transactions and merchandise gross profit; partially offset by
- an increase in operating expenses and selling, general and administrative expenses of $49 million primarily due to higher costs as a result of the 2021 fourth quarter acquisition of refined product terminals and the transmix processing and terminal facility, higher employee costs, credit card processing fees, environmental costs, maintenance costs and acquisition costs.

Investment in USAC

	Three Months Ended June 30,			Six Months Ended June 30,		
	2022	2021	Change	2022	2021	Change
Revenues	$ 172	$ 156	$ 16	$ 335	$ 314	$ 21
Cost of products sold	25	21	4	50	42	8
Segment margin	147	135	12	285	272	13
Operating expenses, excluding non-cash compensation expense	(30)	(24)	(6)	(59)	(52)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(11)	(11)	—	(22)	(20)	(2)
Segment Adjusted EBITDA	$ 106	$ 100	$ 6	$ 204	$ 200	$ 4

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

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment increased primarily due to the net impacts of the following:

- an increase of $12 million in segment margin primarily due to an increase in contract operations revenue as a result of select price increases on USAC's existing fleet and higher revenue generating horsepower, and an increase in parts and service revenue related to an increase in maintenance work performed on units; partially offset by
- an increase of $6 million in operating expenses primarily due to sales tax refunds received in the prior period, an increase in retail parts and services expenses, and an increase in direct labor costs due to higher employee costs in the current period.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our investment in USAC segment increased primarily due to the net impacts of the following:

- an increase of $13 million in segment margin primarily due to an increase in contract operations revenue as a result of select price increases on USAC's existing fleet, higher revenue generating horsepower, and an increase in parts and service revenue related to an increase in maintenance work performed on units; partially offset by
- an increase of $7 million in operating expenses primarily due to sales tax refunds received in the prior period, an increase in USAC's vehicle fleet expenses, an increase in retail parts and services expenses, and an increase in direct labor costs due to higher employee costs in the current period.

All Other

	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	Change	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	Change
Revenues	$ 962	$ 576	$ 386	$ 1,677	$ 2,088	$ (411)
Cost of products sold	882	470	412	1,496	1,812	(316)
Segment margin	80	106	(26)	181	276	(95)
Unrealized (gains) losses on commodity risk management activities	(5)	3	(8)	(1)	2	(3)
Operating expenses, excluding non-cash compensation expense	(24)	(38)	14	(58)	(89)	31
Selling, general and administrative expenses, excluding non-cash compensation expense	(16)	(19)	3	(33)	(58)	25
Adjusted EBITDA related to unconsolidated affiliates	1	—	1	1	(1)	2
Other and eliminations	29	11	18	29	5	24
Segment Adjusted EBITDA	$ 65	$ 63	$ 2	$ 119	$ 135	$ (16)

Amounts reflected in our all other segment primarily include:

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

Segment Adjusted EBITDA. For the three months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment increased primarily due to the net impacts of the following:

- an increase of $9 million due to lower contract labor usage for Energy Transfer Canada;
- an increase of $4 million due to higher coal royalties at our natural resources business; and
- an increase of $3 million due to a favorable environment for our power trading activities; partially offset by
- a decrease of $13 million due to gains in the prior period related to Winter Storm Uri.

Segment Adjusted EBITDA. For the six months ended June 30, 2022 compared to the same period last year, Segment Adjusted EBITDA related to our all other segment decreased primarily due to the net impacts of the following:

- a decrease of $68 million due to gains in the prior period related to Winter Storm Uri; partially offset by
- an increase of $17 million due to higher merger and acquisition expenses in the prior period;
- an increase of $14 million due to lower contract labor usage for Energy Transfer Canada;
- a decrease of $13 million in ad valorem taxes; and
- an increase of $4 million due to higher coal royalties at our natural resources 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 2022 to be within the following ranges (excluding capital expenditures related to our investments in Sunoco LP and USAC):

	Growth		Maintenance	
	Low	High	Low	High
Intrastate transportation and storage	$ 175	$ 200	$ 40	$ 45
Interstate transportation and storage [(1)]	450	500	150	160
Midstream	650	790	140	145
NGL and refined products transportation and services	400	450	120	135
Crude oil transportation and services [(1)]	115	145	105	110
All other (including eliminations)	10	15	60	70
Total capital expenditures	$ 1,800	$ 2,100	$ 615	$ 665

(1) Includes capital expenditures related to our proportionate share of the Bakken, Rover, and Bayou Bridge pipeline joint ventures, as well as the Orbit Gulf Coast NGL Exports joint venture.

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

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally expect to fund growth capital expenditures with proceeds of borrowings under our credit facilities, along with cash from operations.

Sunoco LP currently expects to invest approximately $150 million in growth capital expenditures and approximately $50 million on maintenance capital expenditures for the full year 2022.

USAC currently plans to spend approximately $23 million in maintenance capital expenditures and spend between $100 million and $110 million in expansion capital expenditures for the full year 2022.

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.

Six months ended June 30, 2022 compared to six months ended June 30, 2021. Cash provided by operating activities during 2022 was $4.72 billion compared to $7.16 billion for 2021, and net income was $3.11 billion for 2022 and $4.55 billion for 2021. The difference between net income and net cash provided by operating activities for the six months ended June 30, 2022 primarily consisted of net changes in operating assets and liabilities (net of effects of acquisitions) of $731 million and other non-cash items totaling $2.27 billion.

The non-cash activity in 2022 and 2021 consisted primarily of depreciation, depletion and amortization of $2.07 billion and $1.89 billion, respectively, non-cash compensation expense of $61 million and $55 million, respectively, favorable inventory valuation adjustments of $121 million and $159 million, respectively, deferred income taxes of $107 million and $133 million, respectively, and impairment losses of $300 million and $11 million, respectively. Non-cash activity also included equity in earnings of unconsolidated affiliates of $118 million and $120 million in 2022 and 2021, respectively. In 2021, we also had losses on extinguishments of debt of $8 million.

Cash provided by operating activities includes cash distributions received from unconsolidated affiliates that are deemed to be paid from cumulative earnings, which distributions were $108 million in 2022 and $100 million in 2021.

Cash paid for interest, net of interest capitalized, was $1.10 billion and $1.14 billion for the six months ended June 30, 2022 and 2021, respectively. Interest capitalized was $55 million and $60 million for the six months ended June 30, 2022 and 2021, 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.

Six months ended June 30, 2022 compared to six months ended June 30, 2021. Cash used in investing activities during 2022 was $1.95 billion compared to $1.33 billion for 2021. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2022 were $1.42 billion compared to $1.41 billion for 2021. Additional detail related to our capital expenditures is provided in the table below. In 2022, we paid $325 million in cash for the acquisition of Caliche Coastal Holdings, LLC (subsequently renamed Energy Transfer Spindletop LLC) and Sunoco LP paid $264 million in cash related to its acquisition of a transmix processing and terminal facility.

The following is a summary of capital expenditures (including only our proportionate share of the Bakken, Rover, Bayou Bridge, and Orbit Gulf Coast NGL Exports joint ventures, net of contributions in aid of construction costs) on an accrual basis for the six months ended June 30, 2022:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Intrastate transportation and storage	$ 35	$ 20	$ 55
Interstate transportation and storage	262	64	326
Midstream	299	66	365
NGL and refined products transportation and services	144	49	193
Crude oil transportation and services	74	39	113
Investment in Sunoco LP	45	10	55
Investment in USAC	52	12	64
All other (including eliminations)	11	20	31
Total capital expenditures	$ 922	$ 280	$ 1,202

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.

Six months ended June 30, 2022 compared to six months ended June 30, 2021. Cash used in financing activities during 2022 was $2.75 billion compared to $5.92 billion for 2021. During 2022, we had a net decrease in our debt level of $1.02 billion compared to a net decrease of $5.18 billion for 2021.

In 2022 and 2021, we paid distributions of $1.34 billion and $898 million, respectively, to our partners. In 2022 and 2021, we paid distributions of $753 million and $760 million, respectively, to noncontrolling interests. In 2022 and 2021, we paid distributions of $24 million to our redeemable noncontrolling interests. In 2022 and 2021, we paid debt issuance costs of $9 million and $3 million, respectively.

In 2022 and 2021, we received capital contributions of $397 million and $63 million, respectively, in cash from noncontrolling interests. During 2021, we received $889 million from a sale of preferred units.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	June 30, 2022	December 31, 2021
Energy Transfer Indebtedness:		
Notes and Debentures	$ 37,433	$ 37,733
Five-Year Credit Facility	2,527	2,937
Subsidiary Indebtedness:		
Transwestern Senior Notes	250	400
Panhandle Notes and Debentures	235	235
Bakken Senior Notes [(1)]	1,850	2,500
Sunoco LP Senior Notes and lease-related obligations	2,694	2,700
USAC Senior Notes	1,475	1,475
HFOTCO Tax Exempt Notes	225	225
Revolving credit facilities:		
Sunoco LP Credit Facility	869	581
USAC Credit Facility	559	516
Energy Transfer Canada Revolving Credit Facility [(2)]	79	7
Energy Transfer Canada KAPS Facility [(2)]	233	142
Energy Transfer Canada Term Loan A [(2)]	234	249
Other long-term debt	3	3
Net unamortized premiums, discounts, and fair value adjustments	210	238
Deferred debt issuance costs	(227)	(239)
Total debt	48,649	49,702
Less: current maturities of long-term debt	2	680
Less: long-term debt held for sale	543	—
Long-term debt, less current maturities	$ 48,104	$ 49,022

(1) For December 31, 2021, this balance includes $650 million aggregate principal amount of 3.625% Senior Notes due April 2022 included in current maturities of long-term debt. These notes were repaid in April 2022.

(2) These balances are included in current liabilities held for sale on the Partnership’s consolidated balance sheet as of June 30, 2022.

Recent Transactions

Senior Notes

In February 2022, the Partnership redeemed its $300 million aggregate principal amount of 4.65% Senior Notes due February 2022 using proceeds from its Five-Year Credit Facility (defined below).

In April 2022, Dakota Access redeemed its $650 million aggregate principal amount of 3.625% Senior Notes due April 2022 using proceeds from contributions made by the partners of Dakota Access. The Partnership indirectly owns 36.4% of the ownership interests in Dakota Access.

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 on April 11, 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 June 30, 2022, the Five-Year Credit Facility had $2.53 billion of outstanding borrowings, of which $1.03 billion consisted of commercial paper. The amount available for future borrowings was $2.44 billion, after accounting for outstanding letters of credit in the amount of $33 million. The weighted average interest rate on the total amount outstanding as of June 30, 2022 was 2.68%.

Sunoco LP Credit Facility

As of June 30, 2022, the Sunoco LP Credit Facility had $869 million of outstanding borrowings and $6 million in standby letters of credit and, as amended in April 2022, matures in April 2027. The amount available for future borrowings at June 30, 2022 was $625 million. The weighted average interest rate on the total amount outstanding as of June 30, 2022 was 3.48%.

USAC Credit Facility

As of June 30, 2022, USAC had $559 million of outstanding borrowings and no outstanding letters of credit under the USAC Credit Facility. As of June 30, 2022, USAC had $1.04 billion of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $361 million. The weighted average interest rate on the total amount outstanding as of June 30, 2022 was 4.13%.

Energy Transfer Canada Credit Facilities

As of June 30, 2022, the Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility had outstanding borrowings of C$301 million and C$102 million, respectively (US$234 million and US$79 million, respectively, at the June 30, 2022 exchange rate). As of June 30, 2022, the KAPS Facility had outstanding borrowings of C$300 million (US$233 million at the June 30, 2022 exchange rate).

Compliance with our Covenants

We and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of June 30, 2022.

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 that is necessary or appropriate 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, 2021 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2021	February 8, 2022	February 18, 2022	$ 0.1750
March 31, 2022	May 9, 2022	May 19, 2022	0.2000
June 30, 2022	August 8, 2022	August 19, 2022	0.2300

Cash Distributions on Energy Transfer Preferred Units

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

Period Ended	Record Date	Payment Date	Series A [1]	Series B [1]	Series C	Series D	Series E	Series F [1]	Series G [1]	Series H [1]
December 31, 2021	February 1, 2022	February 15, 2022	$ 31.250	$ 33.125	$ 0.4609	$ 0.4766	$ 0.475	$ —	$ —	$ —
March 31, 2022	May 2, 2022	May 16, 2022	—	—	0.4609	0.4766	0.475	33.750	35.625	32.500
June 30, 2022	August 1, 2022	August 15, 2022	31.250	33.125	0.4609	0.4766	0.475	—	—	—

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

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

Cash Distributions Paid by Sunoco LP

Distributions on Sunoco LP's common units declared and/or paid by Sunoco LP subsequent to December 31, 2021 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2021	February 8, 2022	February 18, 2022	$ 0.8255
March 31, 2022	May 9, 2022	May 19, 2022	0.8255
June 30, 2022	August 8, 2022	August 19, 2022	0.8255

Cash Distributions Paid by USAC

Distributions on USAC's common units declared and/or paid by USAC subsequent to December 31, 2021 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2021	January 24, 2022	February 4, 2022	$ 0.525
March 31, 2022	April 25, 2022	May 6, 2022	0.525
June 30, 2022	July 25, 2022	August 5, 2022	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 18, 2022. No significant changes have occurred subsequent to the Form 10-K filing.

FORWARD-LOOKING STATEMENTS

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

- the volumes transported on our pipelines and gathering systems;
- the level of throughput in our processing and treating facilities;
- the fees we charge and the margins they realize for their gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- impacts of world health events, including the COVID-19 pandemic, escalating global trade tensions and the conflict between Russia and Ukraine and resulting expansion of sanctions and trade restrictions;
- general economic conditions, including sustained periods of inflation and associated central bank monetary policies;
- the possibility of cyber and malware attacks;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas, and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our internal growth projects, such as our construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities, including difficulties in obtaining permits and rights-of-way or other regulatory approvals and the performance by third-party contractors;
- the availability and cost of capital and our ability to access certain capital sources;

- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which we own less than a controlling interests, including risks related to management actions at such entities that we may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;
- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations;
- the costs and effects of legal and administrative proceedings; and
- the risks associated with a potential failure to successfully combine our business with that of Enable.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under “Part I - Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2021 filed with the SEC on February 18, 2022. 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, 2021 filed with the SEC on February 18, 2022, 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, 2021. Since December 31, 2021, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

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

	June 30, 2022			December 31, 2021		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (BBtu):						
Fixed Swaps/Futures	1,023	$ (1)	$ —	585	$ —	$ —
Basis Swaps IFERC/NYMEX [1]	12,198	8	1	(66,665)	(5)	1
Swing Swaps IFERC	543	(1)	—	—	—	—
Power (Megawatt):						
Forwards	527,200	21	3	653,000	2	—
Futures	(289,086)	(9)	1	(604,920)	2	2
Options – Puts	119,200	—	—	(7,859)	—	—
Options – Calls	(308,800)	(7)	1	(30,932)	—	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	20,253	(6)	1	6,738	1	1
Swing Swaps IFERC	(39,755)	14	—	(106,333)	32	31
Fixed Swaps/Futures	(25,520)	(24)	14	(63,898)	(24)	38
Forward Physical Contracts	(7,498)	3	4	(5,950)	1	—
NGLs (MBbls) – Forwards/Swaps	9,869	32	45	8,493	12	19
Crude (MBbls) – Forwards/Swaps	779	14	3	3,672	13	2
Refined Products (MBbls) – Futures	(2,748)	33	41	(3,349)	(15)	32
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(20,383)	4	—	(40,533)	1	—
Fixed Swaps/Futures	(20,383)	26	12	(40,533)	41	14

(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 June 30, 2022, we and our subsidiaries had $5.33 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $53 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

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

		Notional Amount Outstanding	
Term	Type[(1)]	June 30, 2022	December 31, 2021
July 2022[(2)]	Forward-starting to pay an average fixed rate of 3.80% and receive a floating rate	$ —	$ 400
July 2023[(2)]	Forward-starting to pay an average fixed rate of 3.845% and receive a floating rate	400	200
July 2024[(2)]	Forward-starting to pay an average fixed rate of 3.512% and receive a floating rate	400	200

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

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

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $176 million as of June 30, 2022. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of senior management, including the Co-Chief Executive Officers (“Co-Principal Executive Officer”) and the Chief Financial Officer (“Principal Financial Officer”) of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officers and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of June 30, 2022 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officers and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended June 30, 2022 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 18, 2022 and Note 10 in "Item 1. Financial Statements" in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2022.

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

Pursuant to the instructions to Form 10-Q, matters disclosed in this Part II - Item 1 include any reportable legal proceeding (i) that has been terminated during the period covered by this report, (ii) that became a reportable event during the period covered by this report, or (iii) for which there has been a material development during the period covered by this report.

On June 29, 2022, near Henderson, Tennessee, a Mid Valley Pipeline Company mowing contractor struck an exposed section of the 22-inch diameter Hornsby to Denver line segment while mowing. The brush cutter mowing implement cut open the pipeline and released an estimated 4,345 barrels of crude oil into the surrounding area. Approximately 3,343 barrels of crude oil were recovered during initial remediation activities with the remaining volume contained within the materials being removed and disposed of in accordance with applicable environmental laws and regulations. No injuries resulted from the incident. Mid Valley received a Notice of Federal Interest regarding the incident and has also supplied PHMSA with information as requested. No other government agency action has occurred at this time.

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

There have been no material changes from the risk factors described in Part I, Item 1A in the Partnership's Annual Report on Form10-K for the year ended December 31, 2021 filed with the SEC on February 18, 2022.

ITEM 6. EXHIBITS

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.2 of Form S-1 (File No. 333-128097) filed September 2, 2005)
3.2	Certificate of Amendment of Certificate of Limited Partnership of Energy Transfer Equity, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed October 19, 2018)
3.3	Third Amended Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated February 8, 2006 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed February 14, 2006)
3.4	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated November 1, 2006 (incorporated by reference to Exhibit 3.3.1 of Form 10-K (File No. 1-32740) filed November 29, 2006)
3.5	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated November 9, 2007 (incorporated by reference to Exhibit 3.3.2 of Form 8-K (File No. 1-32740) filed November 13, 2007)
3.6	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated May 26, 2010 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed June 2, 2010)
3.7	Amendment No. 4 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated December 23, 2013 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed December 27, 2013)

Exhibit Number	Description
3.8	Amendment No. 5 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated March 8, 2016 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed March 9, 2016)
3.9	Amendment No. 6 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated October 19, 2018 (incorporated by reference to Exhibit 3.9 of Form 10-Q (File No. 1-32740) filed November 8, 2018)
3.10	Amendment No. 7 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated August 6, 2019 (incorporated by reference to Exhibit 3.10 of Form 10-Q (File No. 1-32740) filed August 8, 2019)
3.11	Amendment No. 8 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated April 1, 2021 (incorporated by reference to Exhibit 2.2 of Form 8-K (File No. 1-32740) filed April 1, 2021)
3.12	Amendment No. 9 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated June 15, 2021 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed June 15, 2021)
10.1	Amended and Restated Credit Agreement, dated as of April 11, 2022, by and among Energy Transfer LP, as borrower, Wells Fargo Bank, National Association., as administrative agent, swingline lender and an LC issuer and the lenders party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K (File No. 1-32740) filed April 12, 2022)
22.1	Issuers and Guarantors of Registered Securities (incorporated by reference to Exhibit 22.1 of Form 10-Q (File No. 1-32740) filed August 5, 2021)
31.1*	Certification of Co-Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Co-Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Co-Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Co-Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.3**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101*	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets; (ii) our Consolidated Statements of Operations; (iii) our Consolidated Statements of Comprehensive Income (Loss); (iv) our Consolidated Statements of 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: August 4, 2022

By: /s/ A. Troy Sturrock

A. Troy Sturrock

Senior Vice President, Controller and Principal Accounting Officer (duly authorized to sign on behalf of the registrant)

Exhibit 31.1

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

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

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

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

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

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

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

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

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

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

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

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

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

Date: August 4, 2022

/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: August 4, 2022

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

Exhibit 31.3

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

I, Bradford D. Whitehurst, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 4, 2022

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

Exhibit 32.1

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

In connection with the quarterly report of Energy Transfer LP (the “Partnership”) on Form 10-Q for the quarter ended June 30, 2022, 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: August 4, 2022

/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 June 30, 2022, 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: August 4, 2022

/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 June 30, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bradford D. Whitehurst, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Date: August 4, 2022

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

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