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

FORM 10-K

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

For the fiscal year ended DECEMBER 31, 2021

or

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

Commission file number 1-32740

ENERGY TRANSFER LP

(Exact name of registrant as specified in its charter)

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

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

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

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**

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value as of June 30, 2021, of the registrant's Common Units held by non-affiliates of the registrant, based on the reported closing price of such Common Units on the New York Stock Exchange on such date, was $28.65 billion.

At February 11, 2022, the registrant had 3,082,828,515 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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Definitions

The following is a list of certain acronyms and terms used throughout this document:

/d	per day
Adjusted EBITDA	a non-GAAP measure defined as earnings before interest, taxes, depreciation, depletion, amortization and other non-cash items, as further described in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations”
AOCI	accumulated other comprehensive income (loss)
AROs	asset retirement obligations
BBtu	billion British thermal units
Bcf	billion cubic feet
Btu	British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy content
Capacity	capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels
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
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
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 GC NGL	Energy Transfer GC NGLs LLC, formerly Lone Star NGL LLC, a wholly-owned subsidiary of Energy Transfer
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 and Series G Preferred Units (all as originally issued by ETO and exchanged for preferred units issued by Energy Transfer on April 1, 2021), as well as the Series H Preferred Units issued by Energy Transfer in June 2021
Energy Transfer R&M	Energy Transfer (R&M), LLC (formerly Sunoco (R&M), LLC)
EPA	United States Environmental Protection Agency
ETC Sunoco	ETC Sunoco Holdings LLC (formerly Sunoco, Inc.), a wholly-owned subsidiary of Energy Transfer
ETC Tiger	ETC Tiger Pipeline, LLC, a wholly-owned subsidiary of Energy Transfer, which owns the Tiger Pipeline
ETO	Energy Transfer Operating, L.P., a wholly-owned subsidiary of Energy Transfer (formerly less than wholly-owned until April 2021)
ETP Holdco	ETP Holdco Corporation, a wholly-owned subsidiary of Energy Transfer
Exchange Act	Securities Exchange Act of 1934, as amended
FEP	Fayetteville Express Pipeline LLC
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Pipeline and/or 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
IDRs	incentive distribution rights
IRS	Internal Revenue Service
Lake Charles LNG	Lake Charles LNG Company, LLC, a wholly-owned subsidiary of Energy Transfer
LCL	Lake Charles LNG Export Company, LLC, a wholly-owned subsidiary of Energy Transfer
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Lobo	Lobo Pipeline Company LLC, a wholly-owned subsidiary of Energy Transfer
MBbls	thousand barrels
MEP	Midcontinent Express Pipeline LLC
Mid-Valley	Mid-Valley Pipeline Company, a wholly-owned subsidiary of Energy Transfer
MMBbls	million barrels
MMcf	million cubic feet
MTBE	methyl tertiary butyl ether
NGA	Natural Gas Act of 1938
NGL	natural gas liquid, such as propane, butane and natural gasoline
NGPA	Natural Gas Policy Act of 1978
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
ORS	Ohio River System LLC, a less than wholly-owned subsidiary of Energy Transfer
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
PCBs	polychlorinated biphenyls
Pelico	Pelico Pipeline, LLC, a wholly-owned subsidiary of Energy Transfer
PEP	Permian Express Partners LLC, a less than wholly-owned subsidiary of Energy Transfer
PHMSA	Pipeline Hazardous Materials Safety Administration
Preferred Unitholders	Unitholders of 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, collectively
Regency	Regency Energy Partners LP, a wholly-owned subsidiary of Energy Transfer
RIGS	Regency Intrastate Gas System, a wholly-owned subsidiary of Energy Transfer
Rover	Rover Pipeline LLC, a less than wholly-owned subsidiary of Energy Transfer
Sea Robin	Sea Robin Pipeline Company, LLC, a wholly-owned subsidiary of Panhandle
SEC	Securities and Exchange Commission
SemGroup	SemGroup, LLC (formerly SemGroup Corporation), a wholly-owned subsidiary of Energy Transfer
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
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas Storage Company)
SPLP	Sunoco Pipeline L.P., a wholly-owned subsidiary of Energy Transfer
Transwestern	Transwestern Pipeline Company, LLC, a wholly-owned subsidiary of Energy Transfer
TRRC	Texas Railroad Commission
Trunkline	Trunkline Gas Company, LLC, a wholly-owned subsidiary of Panhandle
Unitholders	Preferred Unitholders and holders of Energy Transfer LP common units
USAC	USA Compression Partners, LP, a subsidiary of Energy Transfer
White Cliffs	White Cliffs Pipeline, L.L.C.

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer LP (the "Partnership" or "Energy Transfer") in periodic press releases and some oral statements of the Partnership's officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend," "continue," "could," "believe," "may," "will" or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from those anticipated, estimated, projected, forecasted, expressed or expected in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management's control. For additional discussion of risks, uncertainties and assumptions, see the risk factor summary below and "Item 1A. Risk Factors" included in this annual report.

Risk Factor Summary

Summary of Risks Related to the Partnership's Business

Results of Operations and Financial Condition. Our results of operations and financial condition could be impacted by many risks that are beyond our control, including the following:

- fluctuations in the demand for and price of natural gas, NGLs, crude oil and refined products;
- the outbreak of COVID-19 and recent geopolitical developments in the crude oil market;
- failure to successfully combine the businesses of Energy Transfer and Enable;
- an impairment of goodwill and intangible assets;
- an interruption of supply of crude oil to our facilities;
- the loss of any key producers or customers;
- failure to retain or replace existing customers or volumes due to declining demand or increased competition;
- unfavorable changes in natural gas price spreads between two or more physical locations;
- production declines over time, which we may not be able to replace with production from newly drilled wells;
- competition for water resources or limitations on water usage for hydraulic fracturing;
- our customers' ability to use our pipelines and third-party pipelines over which we have no control;
- the inability to access or continue to access lands owned by third parties;
- the overall forward market for crude oil and other products we store;
- a natural disaster, catastrophe, terrorist attack or other similar event;
- extreme weather events that may be more severe or frequent than historically experienced and that may be attributable to changes in climate due to the adverse effects of an industrialized economy;
- union disputes and strikes or work stoppages by unionized employees;
- cybersecurity breaches and other disruptions or failures of our information systems;
- failure to establish or maintain adequate corporate governance;
- product liability claims and litigation, or increased insurance costs including as a result of increased risks due to the potential adverse effects of changes in climate;
- actions taken by certain of our joint ventures that we do not control;
- increasing levels of congestion in the Houston Ship Channel;
- the costs of providing pension and other postretirement health care benefits and related funding requirements;
- mergers among customers and competitors;
- fraudulent activity or misuse of proprietary data involving our outsourcing partners; and
- losses resulting from the use of derivative financial instruments.

Indebtedness. Our business, results of operations, cash flows and financial condition, as well as our ability to make distributions, could be impacted by the following:

- our debt level and debt agreements, or increases in interest rates;
- the credit and risk profile of our general partner and its owners; and
- a downgrade of our credit ratings.

Capital Projects and Future Growth. Our business, results of operations, cash flows, financial condition, and future growth could be impacted by the following:

- failure to make acquisitions on economically acceptable terms, or to successfully integrate acquired assets;
- failure to secure debt and equity financing for capital projects on acceptable terms, including as a result of changes in financial institutions' policies or practices concerning businesses linked to fossil fuels;
- failure to construct new pipelines or to do so efficiently;
- failure to execute our growth strategy due to increased competition within any of our core businesses; and
- failure to attract and retain qualified employees; and
- failure of the liquefaction project to secure long-term contractual arrangements or necessary approvals.

Regulatory Matters. Our business, results of operations, cash flows, financial condition, and future growth could be impacted by the following:

- increased regulation of hydraulic fracturing or produced water disposal;
- legal or regulatory actions related to the Dakota Access Pipeline;
- laws, regulations and policies governing the rates, terms and conditions of our services;
- failure to recover the full amount of increases in the costs of our pipeline operations;
- imposition of regulation on assets not previously subject to regulation;
- costs and liabilities resulting from performance of pipeline integrity programs and related repairs;

- new or more stringent pipeline safety controls or enforcement of legal requirements;
- costs and liabilities associated with environmental and worker health and safety laws and regulations;
- climate change legislation or regulations restricting emissions of greenhouse gases, limiting oil and gas leases on federal lands, discouraging oil and gas development or otherwise increasing our or our customers' costs;
- increased attention to environmental, social, and governance ("ESG") matters and conservation measures;
- regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder;
- deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration, development, oil spill-response and decommissioning plans, and related developments; and
- laws and regulations governing the specifications of products that we store and transport.

Risks Relating to Our Partnership Structure

Cash Distributions to Unitholders. Our cash distributions could be impacted by the following:

- our general partner's absolute discretion in issuing an unlimited number of limited partner interests or other classes of equity without the consent of our Unitholders;
- cash distributions are not guaranteed and may fluctuate with our performance and other external factors;
- limitations on available cash that are imposed by our distribution policy;
- our general partner's absolute discretion in determining the level of cash reserves; and
- unitholders' potential liability to repay distributions.

Our General Partner. Our stakeholders could be impacted by risks related to our general partner, including:

- transfer of control of our general partner to a third party without unitholder consent;
- the rights of the majority owner of our general partner that protect him against dilution; and
- substantial cost reimbursements due to our general partner.

Our Subsidiaries. Risks that are unique to our subsidiaries and/or our relationship to our subsidiaries could reduce our subsidiaries' cash available for distributions to us, including:

- the potential issuance of additional common units by Sunoco LP or USAC;
- a significant decrease in demand for or the price of motor fuel in the areas Sunoco LP serves;
- disruptions in Sunoco LP's operations due to dangers inherent in motor fuel transportation;
- seasonal industry trends, which may cause Sunoco LP's operating costs to fluctuate;
- adverse publicity for Sunoco LP resulting from negative events or developments;
- increased costs to retain necessary land use, which could disrupt Sunoco LP's operations; and
- federal, state and local laws and regulations that govern the industries in which our subsidiaries operate.

Risks Related to Conflicts of Interest. Our stakeholders could be impacted by conflicts of interest, including:

- our general partner may favor its own interests to the detriment of our Unitholders;
- fiduciary duties owed to Sunoco LP, USAC and their respective unitholders by their general partners; and
- potential conflicts of interest faced by directors and officers in managing our business.

Tax Risks. Our stakeholders could be impacted by tax risks, including:

- our tax treatment depends on our status as a partnership for federal income tax purposes, and not being subject to a material amount of entity-level taxation;
- our cash available for distribution to Unitholders may be substantially reduced if we become subject to entity-level taxation as a result of the IRS treating us as a corporation or legislative, judicial or administrative changes, and may also be reduced by any audit adjustments if imposed directly on the partnership;
- even if Unitholders do not receive any cash distributions from us, Unitholders will be required to pay taxes on their share of our taxable income;
- a Unitholder's share of our taxable income may be increased as a result of the IRS successfully contesting any of the federal income tax positions we take; and
- treatment of distributions on Energy Transfer Preferred Units as guaranteed payments for the use of capital is uncertain and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

PART I

ITEM 1. BUSINESS

Overview

Energy Transfer LP is a Delaware limited partnership with common units publicly traded on the NYSE under the ticker symbol "ET."

Unless the context requires otherwise, references to "we," "us," "our," the "Partnership" and "Energy Transfer" mean Energy Transfer LP and its consolidated subsidiaries, which include Panhandle, Sunoco LP, USAC and Lake Charles LNG.

The primary activities in which we are engaged, which are in the United States and Canada, and the operating subsidiaries through which we conduct those activities are as follows:

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

In addition, we own investments in other businesses, including Sunoco LP and USAC, both of which are publicly traded master limited partnerships.

Energy Transfer derives cash flows from distributions related to its investment in its subsidiaries, including Sunoco LP and USAC. Energy Transfer's primary cash requirements are for distributions to its partners, general and administrative expenses and debt service requirements. Energy Transfer distributes its available cash remaining after satisfaction of the aforementioned cash requirements to its Unitholders on a quarterly basis.

We expect our subsidiaries to utilize their resources, along with cash from their operations, to fund their announced growth capital expenditures and working capital needs; however, Energy Transfer may issue debt or equity securities from time to time as we deem prudent to provide liquidity for new capital projects of our subsidiaries or for other partnership purposes.

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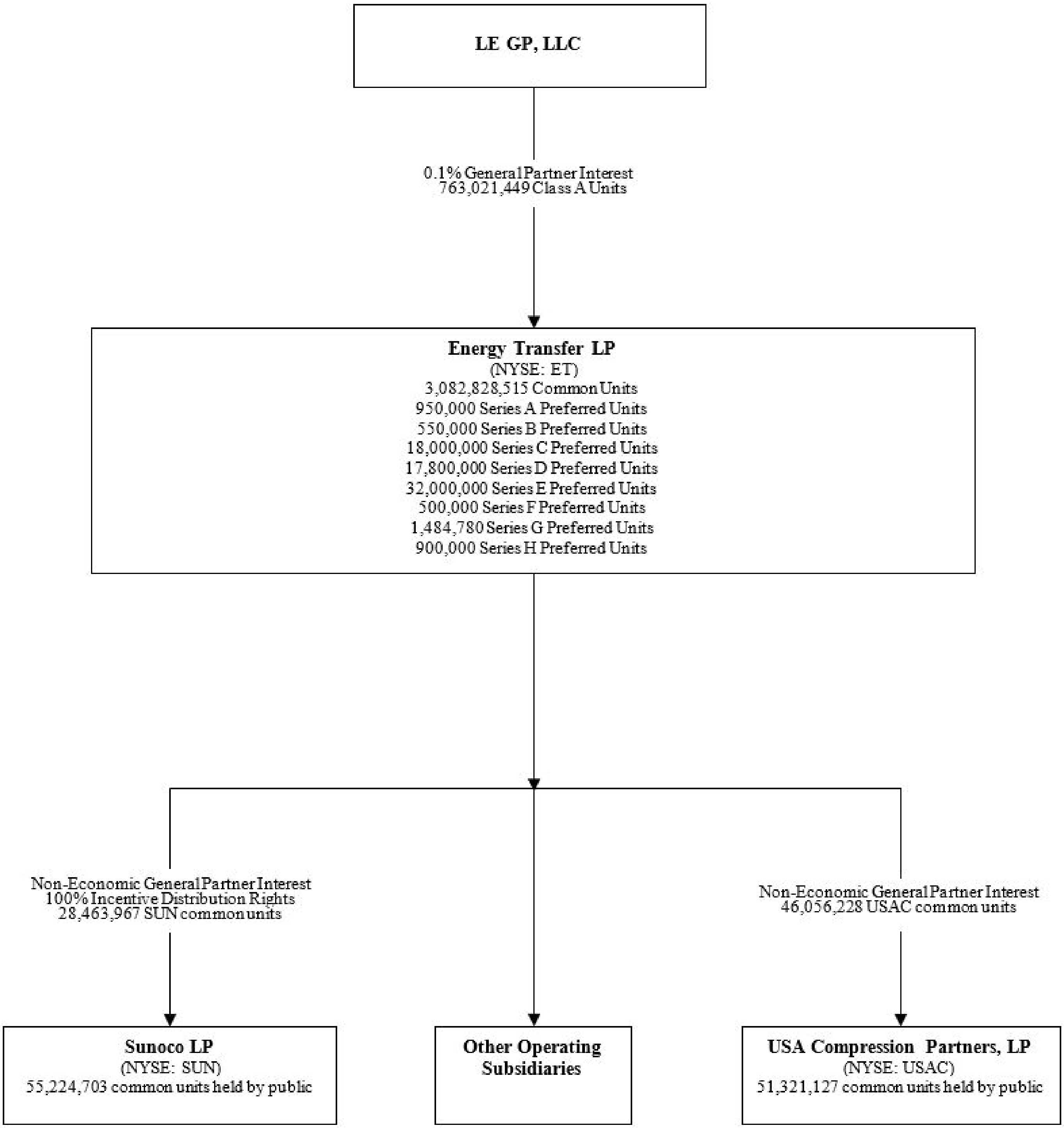
The following chart summarizes our organizational structure as of February 11, 2022. For simplicity, certain immaterial entities and ownership interests have not been depicted.



Significant Achievements in 2021

- In December 2021, Energy Transfer and Enable completed the previously announced merger, under which Enable's common unit holders received 0.8595 of an Energy Transfer common unit in exchange for each Enable common unit (the "Enable Acquisition"). In addition, each outstanding Enable Series A preferred unit was exchanged for 0.0265 of an Energy Transfer Series G preferred unit, and Energy Transfer made a $10 million cash payment for Enable's general partner.
- On April 1, 2021, Energy Transfer, ETO and certain of ETO's subsidiaries consummated several internal reorganization transactions (the "Rollup Mergers"). In connection with the Rollup Mergers, ETO merged with and into Energy Transfer, with Energy Transfer surviving. The impacts of the Rollup Mergers also included the following:
  - All of ETO's long-term debt was assumed by Energy Transfer, as more fully described in Note 6 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data."
  - Each issued and outstanding ETO preferred unit was converted into the right to receive one newly created Energy Transfer preferred unit. A description of the Energy Transfer Preferred Units is included in Note 8 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data."
  - Each of ETO's issued and outstanding Class K, Class L, Class M and Class N units were converted into an aggregate 675,625,000 newly created Class B Units representing limited partner interests in Energy Transfer. All of the Class B Units are held by ETP Holdco, a wholly-owned subsidiary of Energy Transfer.

Segment Overview

See Note 16 to our consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" for additional financial information about our segments.

Intrastate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users, storage facilities, utilities, power generators and other third-party pipelines. Through our intrastate transportation and storage segment, we own and operate (through wholly-owned subsidiaries or through joint venture interests) approximately 11,600 miles of natural gas transportation pipelines with approximately 24 Bcf/d of transportation capacity, three natural gas storage facilities located in the state of Texas and two natural gas storage facilities located in the state of Oklahoma.

Energy Transfer operates one of the largest intrastate pipeline systems in the United States providing energy logistics to major trading hubs and industrial consumption areas throughout the United States. Our intrastate transportation and storage segment focuses on the transportation of natural gas to major markets from various prolific natural gas producing areas (Permian, Barnett, Haynesville and Eagle Ford Shale) through our Oasis pipeline, our ETC Katy pipeline, our natural gas pipeline and storage systems that are referred to as the ET Fuel System, and our HPL System, as further described below.

Our intrastate transportation and storage segment's results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay a fee even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and marketing companies on our HPL System. Generally, we purchase natural gas from either the market (including purchases from our marketing operations) or from producers at the wellhead. To the extent the natural gas comes from producers, it is primarily purchased at a discount to a specified market price and typically resold to customers based on an index price. In addition, our intrastate transportation and storage segment generates revenues from fees charged for storing customers' working natural gas in our storage facilities and from managing natural gas for our own account.

Interstate Transportation and Storage Segment

Natural gas transportation pipelines receive natural gas from supply sources including other transportation pipelines, storage facilities and gathering systems and deliver the natural gas to industrial end-users and other pipelines. Through our interstate transportation and storage segment, we directly own and operate approximately 19,830 miles of interstate natural gas pipelines with approximately 18.5 Bcf/d of transportation capacity and another approximately 7,070 miles and 12.0 Bcf/d of transportation capacity through joint venture interests.

Our vast interstate natural gas network spans the United States from Florida to California and Texas to Michigan, offering a comprehensive array of pipeline and storage services. Our pipelines have the capability to transport natural gas from nearly all Lower 48 onshore and offshore supply basins to customers in the Southeast, Gulf Coast, Southwest, Midwest, Northeast and Canada. Through numerous interconnections with other pipelines, our interstate systems can access virtually any supply or market in the country. As discussed further herein, our interstate segment operations are regulated by the FERC, which has broad regulatory authority over the business and operations of interstate natural gas pipelines.

Lake Charles LNG, our wholly-owned subsidiary, owns an LNG import terminal and regasification facility located on Louisiana's Gulf Coast near Lake Charles, Louisiana. The import terminal has approximately 9.0 Bcf of above ground storage capacity and the regasification facility has a send out capacity of 1.8 Bcf/d. Lake Charles LNG derives all of its revenue from a series of long-term contracts with a wholly-owned subsidiary of Royal Dutch Shell plc ("Shell").

LCL, our wholly-owned subsidiary, is currently developing a natural gas liquefaction project at the site of our Lake Charles LNG import terminal and regasification facility. The project would utilize existing dock and storage facilities owned by Lake Charles LNG located on the Lake Charles site. LCL entered into a prior development agreement with Shell in March 2019; however, Shell withdrew from the project in March 2020 due to adverse market factors affecting Shell's business following the onset of the COVID-19 pandemic. We intend to continue to develop the project, possibly in conjunction with one or more equity partners, and we plan to evaluate a variety of alternatives to advance the project, including the possibility of reducing the size of the project from three trains (16.45 million tonnes per annum of LNG capacity) to two trains (11.0 million tonnes per annum). The project as currently designed is fully permitted by federal, state and local authorities, has all necessary export licenses and benefits from the infrastructure related to the existing regasification facility at the same site, including four LNG storage tanks, two deep water docks and other assets. In light of the existing brownfield infrastructure and the advanced state of the development of the project, we are actively developing the project on a disciplined, cost effective basis, and ultimately we will determine whether to make a final investment decision to proceed with the project based on market conditions, capital expenditure considerations and our success in securing long-term LNG offtake commitments on satisfactory terms. In this regard, market conditions for long-term LNG offtake contracts have improved during the second half of 2021, and LCL is in active discussions with several potential offtake customers for significant volumes of LNG. LCL expects that it would solicit equity participation in the project in order to reduce LCL's capital commitments to the project and correspondingly reduce our capital requirements to construct the project. Based on the estimated time necessary for construction of the liquefaction facility, LCL has filed a request with FERC for approval of an extension of the deadline for completion of construction to December 2028 from the current deadline of December 2025. LCL believes that such approval will be granted in the second quarter of 2022.

The results from our interstate transportation and storage segment are primarily derived from the fees we earn from natural gas transportation and storage services.

Midstream Segment

The midstream industry consists of natural gas gathering, compression, treating, processing, storage, and transportation, and is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells and the proximity of storage facilities to production areas and end-use markets. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems, that collect natural gas from points near producing wells and transports it to larger pipelines for further transportation.

Treating plants remove carbon dioxide and hydrogen sulfide from natural gas that is higher in carbon dioxide, hydrogen sulfide or certain other contaminants, to ensure that it meets pipeline quality specifications. Natural gas processing involves the separation of natural gas into pipeline quality natural gas, or residue gas, and a mixed NGL stream. Some natural gas produced by a well does not meet the pipeline quality specifications established by downstream pipelines or is not suitable for commercial use and must be processed to remove the mixed NGL stream. In addition, some natural gas can be processed to take advantage of favorable margins for NGLs extracted from the gas stream.

Through our midstream segment, we own and operate natural gas gathering and NGL pipelines, natural gas processing plants, natural gas treating facilities and natural gas conditioning facilities with an aggregate processing capacity of approximately 11.2 Bcf/d. Our midstream segment focuses on the gathering, compression, treating, blending, and processing, and our operations are currently concentrated in major producing basins and shales in South Texas, West Texas, New Mexico, North Texas, East Texas, West Virginia, Pennsylvania, Ohio, Oklahoma, Arkansas, Kansas and Louisiana. Many of our midstream assets are integrated with our intrastate transportation and storage assets.

Our midstream segment includes a 60% interest in Edwards Lime Gathering, LLC, which operates natural gas gathering, oil pipeline and oil stabilization facilities in South Texas, a 75% membership interest in ORS, which operates a natural gas gathering system in the Utica shale in Ohio and a 50% membership interest in Atoka Midstream LLC, which owns a natural gas gathering system in Oklahoma.

Our midstream segment results are derived primarily from margins we earn for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems and the natural gas and NGL volumes processed at our processing and treating facilities.

NGL and Refined Products Transportation and Services Segment

Our NGL operations transport, store and execute acquisition and marketing activities utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGL markets.

Our NGL and refined products transportation and services segment includes:

- approximately 5,215 miles of NGL pipelines;
- Nederland Terminal and connecting pipelines which provide transportation of ethane, propane, butane and natural gasoline from our Mont Belvieu Facility to our Nederland Terminal where these products can be exported;
- Marcus Hook Terminal which includes fractionation, storage and exporting assets. This facility is connected to our Mariner East pipeline system, which provides for the transportation of ethane and LPG products from western Pennsylvania, West Virginia and eastern Ohio to our Marcus Hook Terminal where these component products can be exported, processed or locally distributed;
- NGL and propane fractionation facilities with an aggregate capacity of 975 MBbls/d;
- NGL storage facility in Mont Belvieu with a working storage capacity of approximately 50 MMBbls; and
- other NGL storage assets, located at our Cedar Bayou and Hattiesburg storage facilities, and our Nederland, Marcus Hook and Inkster NGL terminals with an aggregate storage capacity of approximately 17 MMBbls.

The NGL pipelines primarily transport NGLs from the Permian and Delaware basins and the Barnett and Eagle Ford Shales to Mont Belvieu.

NGL terminalling services are facilitated by approximately 10 MMBbls of NGL storage capacity. These operations also support our liquids blending activities, including the use of our patented butane blending technology. Refined products operations provide transportation and terminalling services through the use of approximately 3,595 miles of refined products pipelines and 37 active refined products marketing terminals. Our marketing terminals are located primarily in the northeast, midwest and southwest United States, with approximately 8 MMBbls of refined products storage capacity. Our refined products operations utilize our integrated pipeline and terminalling assets, as well as acquisition and marketing activities, to service refined products markets in several regions throughout the United States. The mix of products delivered through our refined products pipelines varies seasonally, with gasoline demand peaking during the summer months, and demand for heating oil and other distillate fuels peaking in the winter. The products transported in these pipelines include multiple grades of gasoline and middle distillates, such as heating oil, diesel and jet fuel. Rates for shipments on these product pipelines are regulated by the FERC and other state regulatory agencies, as applicable.

Revenues in this segment are principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Fees are market-based, negotiated with customers and competitive with regional regulated pipelines and fractionators. Storage revenues are derived from base storage and throughput fees. This segment also derives revenues from the marketing of NGLs and processing and fractionating refinery off-gas.

Crude Oil Transportation and Services Segment

Our crude oil operations provide transportation (via pipeline and trucking), terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest, northwestern and northeastern United States. Through our crude oil transportation and services segment, we own and operate (through wholly-owned subsidiaries or joint venture interests) approximately 11,315 miles of crude oil trunk and gathering pipelines in the southwestern, northwestern and midwestern United States. This segment includes equity ownership interests in six crude oil pipeline systems, the Bakken Pipeline system, Bayou Bridge Pipeline, White Cliffs Pipeline, Maurepas Pipeline, the Permian Express pipelines and Enable South Central Pipeline. Our crude oil terminalling services operate with an aggregate storage capacity of approximately 66 MMBbls, including approximately 31 MMBbls at our Gulf Coast terminal in Nederland, Texas, approximately 18.2 MMBbls at our Gulf coast terminal on the Houston Ship Channel and approximately 7.7 MMBbls at our Cushing facility in Cushing, Oklahoma. Our crude oil acquisition and marketing activities utilize our pipeline and terminal assets, our proprietary fleet crude oil tractor trailers and truck unloading facilities, as well as third-party assets, to service crude oil markets principally in the midcontinent United States.

Revenues throughout our crude oil pipeline systems are generated from tariffs paid by shippers utilizing our transportation services. These tariffs are filed with the FERC and other state regulatory agencies, as applicable.

Our crude oil acquisition and marketing activities include the gathering, purchasing, marketing and selling of crude oil. Specifically, the crude oil acquisition and marketing activities include:

- purchasing crude oil at both the wellhead from producers, and in bulk from aggregators at major pipeline interconnections and trading locations;
- storing inventory during contango market conditions (when the price of crude oil for future delivery is higher than current prices);
- buying and selling crude oil of different grades at different locations in order to maximize value;
- transporting crude oil using the pipelines, terminals and trucks or, when necessary or cost effective, pipelines, terminals or trucks owned and operated by third parties; and
- marketing crude oil to major integrated oil companies, independent refiners and resellers through various types of sale and exchange transactions.

Investment in Sunoco LP

Sunoco LP is engaged in the distribution of motor fuels to independent dealers, distributors, and other commercial customers and the distribution of motor fuels to end-user customers at retail sites operated by commission agents. Additionally, it receives rental income through the leasing or subleasing of real estate used in the retail distribution of motor fuel. Sunoco LP also operates 78 retail stores located in Hawaii and New Jersey.

Sunoco LP is a distributor of motor fuels and other petroleum products which Sunoco LP supplies to third-party dealers and distributors, to independent operators of commission agent locations and other commercial consumers of motor fuel. Also included in the wholesale operations are transmix processing plants and refined products terminals. Transmix is the mixture of various refined products (primarily gasoline and diesel) created in the supply chain (primarily in pipelines and terminals) when various products interface with each other. Transmix processing plants separate this mixture and return it to salable products of gasoline and diesel.

Sunoco LP is the exclusive wholesale supplier of the Sunoco-branded motor fuel, supplying an extensive distribution network of approximately 5,513 Sunoco-branded company and third-party operated locations throughout the East Coast, Midwest, South Central and Southeast regions of the United States. In addition to distributing motor fuels, Sunoco LP also distributes other petroleum products such as propane and lubricating oil, and Sunoco LP receives rental income from real estate that it leases or subleases.

Sunoco LP operations primarily consist of fuel distribution and marketing.

Investment in USAC

USAC provides natural gas compression services throughout the United States, including the Utica, Marcellus, Permian Basin, Delaware Basin, Eagle Ford, Mississippi Lime, Granite Wash, Woodford, Barnett, Haynesville, Niobrara and Fayetteville shales. USAC provides compression services to its customers primarily in connection with infrastructure applications, including both allowing for the processing and transportation of natural gas through the domestic pipeline system and enhancing crude oil production through artificial lift processes. As such, USAC's compression services play a critical role in the production, processing and transportation of both natural gas and crude oil. As of December 31, 2021, USAC had 3.7 million horsepower in its fleet.

USAC operates a modern fleet of compression units, with an average age of approximately nine years. USAC's standard new-build compression units are generally configured for multiple compression stages allowing USAC to operate its units across a broad range of operating conditions. As part of USAC's services, it engineers, designs, operates, services and repairs its compression units and maintains related support inventory and equipment.

USAC provides compression services to its customers under fixed-fee contracts with initial contract terms typically between six months and five years, depending on the application and location of the compression unit. USAC typically continues to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. USAC primarily enters into fixed-fee contracts whereby its customers are required to pay a monthly fee even during periods of limited or disrupted throughput, which enhances the stability and predictability of its cash flows. USAC is not directly exposed to commodity price risk because it does not take title to the natural gas or crude oil involved in its services and because the natural gas used as fuel by its compression units is supplied by its customers without cost to USAC.

USAC’s assets and operations are all located and conducted in the United States.

All Other Segment

Our “All Other” segment includes the following:

- Our marketing operations in which we market the natural gas that flows through our gathering and intrastate transportation assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other suppliers and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices of natural gas, less the costs of transportation. For the off-system gas, we purchase gas or act as an agent for small independent producers that may not have marketing operations.
- Our natural gas compression equipment business which has operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas.
- Our wholly-owned subsidiary, Dual Drive Technologies, Ltd. (“DDT”), which provides compression services to customers engaged in the transportation of natural gas, including our other segments.
- Our subsidiaries are involved in the management of coal and natural resources properties and the related collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. These operations also include end-user coal handling facilities.
- Our 51% ownership interest in Energy Transfer Canada, which owns and operates natural gas processing and gathering facilities in Alberta, Canada.

Asset Overview

The descriptions below include summaries of significant assets within the Partnership’s reportable segments. Amounts, such as capacities, volumes and miles included in the descriptions below are approximate and are based on information currently available; such amounts are subject to change based on future events or additional information.

Intrastate Transportation and Storage

The following details our pipelines and storage facilities in the intrastate transportation and storage segment:

Description of Assets	Ownership Interest	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Storage Capacity (Bcf/d)
ET Fuel System	100 %	3,150	5.2	11.2
Oasis Pipeline [1]	100 %	750	2.0	—
HPL System	100 %	3,920	5.3	52.5
ETC Katy Pipeline	100 %	460	2.9	—
Regency Intrastate Gas	100 %	450	2.1	—
Enable Oklahoma Intrastate Transmission	100 %	2,200	2.4	24.0
Comanche Trail Pipeline	16 %	195	1.1	—
Trans-Pecos Pipeline	16 %	140	1.4	—
Old Ocean Pipeline, LLC	50 %	240	0.2	—
Red Bluff Express Pipeline	70 %	120	1.4	—

(1) Includes bi-directional capabilities

The following information describes our principal intrastate transportation and storage assets:

- The ET Fuel System serves some of the most prolific production areas in the United States and is comprised of intrastate natural gas pipeline and related natural gas storage facilities. The ET Fuel System has many interconnections with pipelines providing direct access to power plants, other intrastate and interstate pipelines, and has bi-directional capabilities. It is strategically located near high-growth production areas and provides access to the three major natural gas trading centers in Texas, the Waha Hub near Pecos, Texas, the Maypearl Hub in Central Texas and the Carthage Hub in East Texas.

  The ET Fuel System also includes our Bethel natural gas storage facility, with a working capacity of 6.0 Bcf, an average withdrawal capacity of 300 MMcf/d and an injection capacity of 75 MMcf/d, and our Bryson natural gas storage facility, with a working capacity of 5.2 Bcf, an average withdrawal capacity of 120 MMcf/d and an average injection capacity of 96 MMcf/d. Storage capacity on the ET Fuel System is contracted to third parties under fee-based arrangements that extend through 2023.

  In addition, the ET Fuel System is integrated with our Godley processing plant which gives us the ability to bypass the plant when processing margins are unfavorable by blending the untreated natural gas from the North Texas System with natural gas on the ET Fuel System while continuing to meet pipeline quality specifications.

- The Oasis Pipeline is primarily a 36-inch natural gas pipeline. It has bi-directional capabilities with approximately 1.3 Bcf/d of throughput capacity moving west-to-east and greater than 750 MMcf/d of throughput capacity moving east-to-west. The Oasis pipeline connects to the Waha and Katy market hubs and has many interconnections with other pipelines, power plants, processing facilities, municipalities and producers.

  The Oasis pipeline is integrated with our gathering system known as the Southeast Texas System and is an important component to maximizing our Southeast Texas System's profitability. The Oasis pipeline enhances the Southeast Texas System by (i) providing access for natural gas gathered on the Southeast Texas System to other third-party supply and market points and interconnecting pipelines and (ii) allowing us to bypass our processing plants and treating facilities on the Southeast Texas System when processing margins are unfavorable by blending untreated natural gas from the Southeast Texas System with gas on the Oasis pipeline while continuing to meet pipeline quality specifications.

- The HPL System is an extensive network of intrastate natural gas pipelines, an underground Bammel storage reservoir and related transportation assets. The system has access to multiple sources of historically significant natural gas supply reserves from South Texas, the Gulf Coast of Texas, East Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City, Beaumont and other cities located along the Gulf Coast of Texas. The HPL System is well situated to gather and transport gas in many of the major gas producing areas in Texas including a strong presence in the key Houston Ship Channel and Katy Hub markets, allowing us to play an important role in the Texas natural gas markets. The HPL System also offers its shippers off-system opportunities due to its numerous interconnections with other pipeline systems, its direct access to multiple market hubs at Katy, the Houston Ship Channel, Carthage and Agua Dulce, as well as our Bammel storage facility.

The Bammel storage facility has a total working gas capacity of approximately 52.5 Bcf, a peak withdrawal rate of 1.3 Bcf/d and a peak injection rate of 0.6 Bcf/d. The Bammel storage facility is located near the Houston Ship Channel market area and the Katy Hub, and is ideally suited to provide a physical backup for on-system and off-system customers. As of December 31, 2021, we had approximately 17.2 Bcf committed under fee-based arrangements with third parties and approximately 40.8 Bcf stored in the facility for our own account.

- The ETC Katy Pipeline connects three treating facilities, one of which we own, with our gathering system known as Southeast Texas System. The ETC Katy pipeline serves producers in East and North Central Texas and provided access to the Katy Hub. The ETC Katy pipeline expansions include the 36-inch East Texas extension to connect our Reed compressor station in Freestone County to our Grimes County compressor station, the 36-inch Katy expansion connecting Grimes to the Katy Hub, and the 42-inch Southeast Bossier pipeline connecting our Cleburne to Carthage pipeline to the HPL System.
- RIGS is a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets.
- Enable Oklahoma Intrastate Transmission (“EOIT”) was acquired in the Enable Acquisition in December 2021 and is a 2,200-mile pipeline that provides natural gas transportation and storage services to customers in Oklahoma. The EOIT pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt points and delivery points. The EOIT system delivers natural gas from the Anadarko and Arkoma Basins, including the SCOOP, STACK, Cana Woodford, Granite Wash, Cleveland, Tonkawa and Mississippi Lime Shale plays in western Oklahoma to utilities and industrial end users connected to EOIT and to interstate and intrastate pipelines interconnected with EOIT. EOIT also has two underground natural gas storage facilities in Oklahoma, which operate at a combined capacity of 24 Bcf with a peak withdrawal rate of 0.60 Bcf/d.
- Comanche Trail Pipeline is a 195-mile intrastate pipeline that delivers natural gas from the Waha Hub near Pecos, Texas to the United States/Mexico border near San Elizario, Texas. The Partnership owns a 16% membership interest in and operates Comanche Trail.
- Trans-Pecos Pipeline is a 143-mile intrastate pipeline that delivers natural gas from the Waha Hub near Pecos, Texas to the United States/Mexico border near Presidio, Texas. The Partnership owns a 16% membership interest in and operates Trans-Pecos.
- Old Ocean is a 240-mile intrastate pipeline system that delivers natural gas from Ellis County, Texas to Brazoria County, Texas. The Partnership owns a 50% membership interest in and operates Old Ocean.
- The Red Bluff Express Pipeline is an approximately 120-mile intrastate pipeline that runs through the heart of the Delaware basin and connects our Orla Plant, as well as third-party plants to the Waha Oasis Header. The Partnership owns a 70% membership interest in and operates Red Bluff Express.

Interstate Transportation and Storage

The following details our pipelines in the interstate transportation and storage segment:

Description of Assets	Ownership Interest	Miles of Natural Gas Pipeline	Pipeline Throughput Capacity (Bcf/d)	Working Gas Capacity (Bcf/d)
Florida Gas Transmission	50 %	5,365	3.7	—
Transwestern Pipeline	100 %	2,610	2.1	—
Panhandle Eastern Pipe Line [(1)]	100 %	6,300	2.8	73.4
Trunkline Gas Company	100 %	2,190	0.9	13.0
Tiger Pipeline	100 %	200	2.4	—
Fayetteville Express Pipeline	50 %	185	2.0	—
Sea Robin Pipeline	100 %	740	2.0	—
Stingray Pipeline	100 %	290	0.4	—
Rover Pipeline	32.6 %	720	3.4	—
Midcontinent Express Pipeline	50 %	510	1.8	—
Enable Gas Transmission	100 %	5,900	6.2	29.0
Mississippi River Transmission	100 %	1,600	1.7	31.5
Southeast Supply Header	50 %	290	1.1	—

(1) Natural gas storage assets are owned by Southwest Gas.

The following information describes our principal interstate transportation and storage assets:

- Florida Gas Transmission Pipeline ("FGT") has mainline capacity of 3.7 Bcf/d and approximately 5,362 miles of pipelines extending from south Texas through the Gulf Coast region of the United States to south Florida. The FGT system receives natural gas from various onshore and offshore natural gas producing basins. FGT is the principal transporter of natural gas to the Florida energy market, delivering approximately 60% of the natural gas consumed in the state. In addition, FGT's system operates and maintains multiple interconnects with major interstate and intrastate natural gas pipelines, which provide FGT's customers access to diverse natural gas producing regions. FGT's customers include electric utilities, independent power producers, industrial end-users and local distribution companies. FGT is owned by Citrus, a 50/50 joint venture with Kinder Morgan, Inc.
- Transwestern Pipeline transports natural gas supply from the Permian Basin in West Texas and eastern New Mexico, the San Juan Basin in northwestern New Mexico and southern Colorado, and the Anadarko Basin in the Texas and Oklahoma panhandles. The system has bi-directional capabilities and can access Texas and Midcontinent natural gas market hubs, as well as major western markets in Arizona, Nevada and California. Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users.
- Panhandle Eastern Pipe Line's transmission system consists of four large diameter pipelines with bi-directional capabilities, extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan. Panhandle contracts for over 73 Bcf of natural gas storage.
- Trunkline Gas Company's transmission system consists of one large diameter pipeline with bi-directional capabilities, extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and Michigan. Trunkline has one natural gas storage field located in Louisiana.
- Tiger Pipeline is a bi-directional system that extends through the heart of the Haynesville Shale and ends near Delhi, Louisiana, interconnecting with multiple interstate pipelines.
- Fayetteville Express Pipeline originates near Conway County, Arkansas and continues eastward to Panola County, Mississippi with multiple pipeline interconnections along the route. Fayetteville Express Pipeline is owned by a 50/50 joint venture with Kinder Morgan, Inc.
- Sea Robin Pipeline's system consists of two offshore Louisiana natural gas supply pipelines extending 120 miles into the Gulf of Mexico.

- Stingray Pipeline is an interstate natural gas pipeline system with related assets located in the western Gulf of Mexico and Johnson Bayou, Louisiana. Stingray has recently filed with the FERC to abandon a portion of its system to be used in non-gas service and the remaining portion to be operated as a non-FERC-regulated gathering system. The proceeding is pending a decision from FERC.
- Rover Pipeline is a large diameter pipeline with total capacity to transport 3.4 Bcf/d natural gas from processing plants in West Virginia, Eastern Ohio and Western Pennsylvania for delivery to other pipeline interconnects in Ohio and Michigan, where the gas is delivered for distribution to markets across the United States, as well as to Ontario, Canada.
- Midcontinent Express Pipeline originates near Bennington, Oklahoma and traverses northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipeline system in Butler, Alabama. The Midcontinent Express Pipeline is owned by a 50/50 joint venture with Kinder Morgan, Inc., the operator of the system.
- Enable Gas Transmission ("EGT") was acquired in the Enable Acquisition in December 2021 and provides natural gas transportation and storage services to customers in Oklahoma, Texas, Arkansas, Louisiana, Missouri and Kansas. EGT has approximately 5,900-miles of interstate pipelines and two underground storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which operate at a combined capacity of 29 Bcf with a peak withdrawal rate of 0.7 Bcf/d. Through interconnections with other pipelines and interconnections at the Perryville Hub, EGT customers have access to the Midwest and Northeast markets, as well as most of the major natural gas consuming markets east of the Mississippi River.
- Mississippi River Transmission ("MRT") was acquired in the Enable Acquisition in December 2021 and provides natural gas transportation and storage services in Texas, Arkansas, Louisiana, Missouri and Illinois. MRT has approximately 1,600-miles of interstate pipeline and underground natural gas storage facilities in Louisiana, including the East Unionville and West Unionville fields, and one underground natural gas storage facility in Illinois, which operate on a combined capacity of 31.5 Bcf with a peak withdrawal rate of 0.6 Bcf/d. MRT receives natural gas from a variety of interstate and intrastate pipelines through its interconnections and delivers natural gas primarily to the St. Louis market.
- Our interest in Southeast Supply Header ("SESH") was acquired in the Enable Acquisition in December 2021. SESH, a 50/50 joint venture with Enbridge Inc., provides transportation services in Louisiana, Mississippi and Alabama. SESH operates a 1.09 Bcf of transportation capacity from the Perryville Hub in Louisiana to its endpoint in Mobile County, Alabama. SESH has interconnections with third party natural gas pipelines and provides access to major Southeast and Northeast markets and transports directly to generating facilities in Mississippi and Alabama and to interconnecting pipelines that supply companies generating electricity for the Florida power market.

Regasification Facility

Lake Charles LNG, our wholly-owned subsidiary, owns an LNG import terminal and regasification facility located on Louisiana's Gulf Coast near Lake Charles, Louisiana. The import terminal has approximately 9.0 Bcf of above ground LNG storage capacity and the regasification facility has a send out capacity of 1.8 Bcf/d.

Liquefaction Project

LCL, our wholly-owned subsidiary, is currently developing a natural gas liquefaction project at the site of our Lake Charles LNG import terminal and regasification facility. The project would utilize existing dock and storage facilities owned by Lake Charles LNG located on the Lake Charles site. LCL entered into a prior development agreement with Shell in March 2019; however, Shell withdrew from the project in March 2020 due to adverse market factors affecting Shell's business following the onset of the COVID-19 pandemic. We intend to continue to develop the project, possibly in conjunction with one or more equity partners, and we plan to evaluate a variety of alternatives to advance the project, including the possibility of reducing the size of the project from three trains (16.45 million tonnes per annum of LNG capacity) to two trains (11.0 million tonnes per annum). The project as currently designed is fully permitted by federal, state and local authorities, has all necessary export licenses and benefits from the infrastructure related to the existing regasification facility at the same site, including four LNG storage tanks, two deep water docks and other assets. In light of the existing brownfield infrastructure and the advanced state of the development of the project, we are actively developing the project on a disciplined, cost effective basis, and ultimately we will determine whether to make a final investment decision to proceed with the project based on market conditions, capital expenditure considerations and our success in securing long-term LNG offtake commitments on satisfactory terms. In this regard, market conditions for long-term LNG offtake contracts have improved during the second half of 2021, and LCL is in active discussions with several potential offtake customers for significant volumes of LNG. LCL expects that it would solicit equity participation in the project in order to reduce LCL's capital commitments to the project and correspondingly reduce our capital requirements to construct the project. Based on the estimated time necessary for construction of the liquefaction facility, LCL has filed a request with FERC for approval of an extension of the deadline for completion of construction to December

2028 from the current deadline of December 2025. LCL believes that such approval will be granted in the second quarter of 2022.

The export of LNG produced by the liquefaction project from the United States would be undertaken under long-term export authorizations issued by the DOE to LCL. In March 2013, LCL obtained a DOE authorization to export LNG to countries with which the United States has or will have Free Trade Agreements (“FTA”) for trade in natural gas (the “FTA Authorization”). In July 2016, LCL also obtained a conditional DOE authorization to export LNG to countries that do not have an FTA for trade in natural gas (the “Non-FTA Authorization”). In October 2020, the DOE extended the FTA Authorization and Non-FTA Authorization to 30- and 25-year terms, respectively, following first deliveries on or before December 2025, consistent with the FERC authorization for the project. The FTA Authorization and Non-FTA Authorization have 25- and 20-year terms, respectively, commencing with the completion of construction of the liquefaction facility. In addition, LCL received its wetlands permits from the USACE to perform wetlands mitigation work and to perform modification and dredging work for the temporary and permanent dock facilities at the Lake Charles LNG facilities.

Midstream

The following details our assets in the midstream segment:

Description of Assets	Net Gas Processing Capacity (MMcf/d)
South Texas Region:	
Southeast Texas System	410
Eagle Ford System	1,920
Ark-La-Tex Region	2,090
North Central Texas Region	700
Permian Region	2,740
Midcontinent Region	3,135
Eastern Region	200

The following information describes our principal midstream assets:

South Texas Region:

- The Southeast Texas System is an integrated system that gathers, compresses, treats, processes, dehydrates and transports natural gas from the Austin Chalk trend and Eagle Ford shale formation. The Southeast Texas System is a large natural gas gathering system covering thirteen counties between Austin and Houston. This system is connected to the Katy Hub through the ETC Katy Pipeline and is also connected to the Oasis Pipeline. The Southeast Texas System includes two natural gas processing plants (La Grange and Alamo) with aggregate capacity of 410 MMcf/d. The La Grange and Alamo processing plants are natural gas processing plants that process the rich gas that flows through our gathering system to produce residue gas and NGLs. Residue gas is delivered into our intrastate pipelines and NGLs are delivered into our NGL pipelines to Lone Star.

  Our treating facilities remove carbon dioxide and hydrogen sulfide from natural gas gathered into our system before the natural gas is introduced to transportation pipelines to ensure that the gas meets pipeline quality specifications.

- The Eagle Ford Gathering System consists of 30-inch and 42-inch natural gas gathering pipelines with over 1.4 Bcf/d of capacity originating in Dimmitt County, Texas, and extending to both our King Ranch gas plant in Kleberg County, Texas and Jackson plant in Jackson County, Texas. The Eagle Ford Gathering System includes four processing plants (Chisholm, Kenedy, Jackson and King Ranch) with aggregate capacity of 1.9 Bcf/d. Our Chisholm, Kenedy, Jackson and King Ranch processing plants are connected to our intrastate transportation pipeline systems for deliveries of residue gas and are also connected with our NGL pipelines for delivery of NGLs to Lone Star.

Ark-La-Tex Region:

- Our Northern Louisiana assets are comprised of several gathering systems in the Haynesville Shale with access to multiple markets through interconnects with several pipelines, including our Tiger Pipeline. Our Northern Louisiana assets include the Bistineau, Creedence, and Tristate Systems, which collectively include three natural gas treating facilities, with aggregate capacity of 2.1 Bcf/d.

- The Ark-La-Tex assets gather, compress, treat and dehydrate natural gas in several parishes in north and west Louisiana and several counties in East Texas. These assets also include cryogenic natural gas processing facilities, a refrigeration plant, a conditioning plant, amine treating plants, a residue gas pipeline that provides market access for natural gas from our processing plants, including connections with pipelines that provide access to the Perryville Hub and other markets in the Gulf Coast region, and an NGL pipeline that provides connections to the Mont Belvieu market for NGLs produced from our processing plants. Collectively, the eleven natural gas processing facilities (Dubach, Dubberly, Lisbon, Salem, Elm Grove, Minden, Ada, Brookeland, Lincoln Parish, Rosewood and Mt. Olive) have an aggregate capacity of 1.4Bcf/d. In connection with the Enable Acquisition in December 2021, we acquired three processing plants (Panola, Sligo and Waskom) which have an aggregate capacity of 0.6 Bcf/d.
- Through the gathering and processing systems described above and their interconnections with RIGS in north Louisiana, as well as other pipelines, we offer producers wellhead-to-market services, including natural gas gathering, compression, processing, treating and transportation.

North Central Texas Region:

- The North Central Texas System is an integrated system located in four counties in North Central Texas that gathers, compresses, treats, processes and transports natural gas from the Barnett and Woodford Shales. Our North Central Texas assets include our Godley plant, which processes rich gas produced from the Barnett Shale and STACK play, with aggregate capacity of 700 MMcf/d. The Godley plant is integrated with the ET Fuel System.

Permian Region:

- The Permian Basin Gathering System offers wellhead-to-market services to producers in eleven counties in West Texas, as well as two counties in New Mexico which surround the Waha Hub, one of Texas's developing NGL-rich natural gas market areas. As a result of the proximity of our system to the Waha Hub, the Waha Gathering System has a variety of market outlets for the natural gas that we gather and process, including several major interstate and intrastate pipelines serving California, the midcontinent region of the United States and Texas natural gas markets. The NGL market outlets includes Lone Star's liquids pipelines. The Permian Basin Gathering System includes eleven processing facilities (Waha, Coyanosa, Red Bluff, Halley, Jal, Keyston, Tippet, Orla, Panther, Rebel and Arrowhead) with an aggregate processing capacity of 2.4 Bcf/d and one natural gas conditioning facility with aggregate capacity of 200 MMcf/d.
- We own a 50% membership interest in Mi Vida JV LLC, a joint venture which owns a 200 MMcf/d cryogenic processing plant in West Texas. We operate the plant and related facilities on behalf of the joint venture.
- We own a 50% membership interest in Ranch Westex JV, LLC, which processes natural gas delivered from the NGL-rich Bone Spring and Avalon Shale formations in West Texas. The joint venture owns a 25 MMcf/d refrigeration plant and a 100 MMcf/d cryogenic processing plant.

Midcontinent Region:

- The Midcontinent Systems are located in two large natural gas producing regions in the United States, the Hugoton Basin in southwest Kansas, and the Anadarko Basin in western Oklahoma and the Texas Panhandle and the STACK in central Oklahoma. These mature basins have continued to provide generally long-lived, predictable production volume. Our Midcontinent assets are extensive systems that gather, compress and dehydrate low-pressure gas. The Midcontinent Systems include twelve natural gas processing facilities (Mocane, Beaver, Antelope Hills, Woodall, Wheeler, Sunray, Hemphill, Hamlin, Spearman, Crescent, Rose Valley, and Hopeton) with an aggregate capacity of approximately 1.2 Bcf/d. In connection with the Enable Acquisition in December 2021, we acquired twelve gas processing facilities (Bradley II, Bradley, McClure, Wheeler, South Canadian, Clinton, Roger Mills, Canute, Cox City, Thomas, Calumet and Wetumka) with an aggregate capacity of 1.9 Bcf/d.
- We operate our Midcontinent Systems at low pressures to maximize the total throughput volumes from the connected wells. Wellhead pressures are therefore adequate to allow for flow of natural gas into the gathering lines without the cost of wellhead compression.
- We own the Hugoton Gathering System that has 1,900 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.
- In connection with the Enable Acquisition in December 2021, we acquired a 50% membership interest in Atoka Midstream LLC, which owns a natural gas gathering system in Oklahoma.

Eastern Region:

- The Eastern Region assets are located in eleven counties in Pennsylvania, four counties in Ohio, three counties in West Virginia, and gather natural gas from the Marcellus and Utica basins. Our Eastern Region assets include approximately 600 miles of natural gas gathering pipeline, natural gas trunklines, fresh-water pipelines, and nine gathering and processing systems, as well as the 200 MMcf/d Revolution processing plant, which feeds into our Mariner East and Rover pipeline systems.

- We also own a 51% membership interest in Aqua – ETC Water Solutions LLC, a joint venture that transports and supplies fresh water to natural gas producers drilling in the Marcellus Shale in Pennsylvania.
- We own a 75% membership interest in ORS. On behalf of ORS, we operate its Ohio Utica River System, which consists of 47 miles of 36-inch, 13 miles of 30-inch and 3 miles of 24-inch gathering trunklines, that delivers up to 3.6 Bcf/d to Rockies Express Pipeline, Texas Eastern Transmission, Leach Xpress, Rover and DEO TPL-18.

NGL and Refined Products Transportation and Services

The following details the assets in our NGL and refined products transportation and services segment:

Description of Assets	Miles of Liquids Pipeline	NGL Fractionation / Processing Capacity (MBbls/d)	Working Storage Capacity (MBbls)
Liquids Pipelines:			
Lone Star Express	900	—	—
West Texas Gateway Pipeline	510	—	—
Energy Transfer GC NGL	1,500	—	—
Mariner East	910	—	—
Mariner South	70	—	—
Mariner West	400	—	—
White Cliffs Pipeline[(1)]	540	—	—
Other NGL Pipelines	315	—	—
Liquids Fractionation and Services Facilities:			
Mont Belvieu Facilities	185	940	50,000
Sea Robin Processing Plant[(2)]	—	26	—
ET Geismar Olefins[(2)]	100	35	—
Hattiesburg Storage Facilities	—	—	5,200
Cedar Bayou	—	—	1,600
NGL Terminals:			
Nederland	—	—	1,900
Orbit Gulf Coast	70	—	1,200
Marcus Hook Terminal	—	132	6,000
Inkster	—	—	860
Refined Products Pipelines:			
Eastern region pipelines	1,580	—	—
Midcontinent region pipelines	440	—	—
Southwest region pipelines	495	—	—
Inland Pipeline	580	—	—
JC Nolan Pipeline	500	—	—
Refined Products Terminals:			
Eagle Point	—	—	6,700
Marcus Hook Terminal	—	—	930
Marcus Hook Tank Farm	—	—	1,900
Marketing Terminals	—	—	7,700
JC Nolan Terminal	—	—	130

(1) The White Cliffs Pipeline consists of two parallel, 12-inch common carrier pipelines: one crude oil pipeline and one NGL pipeline.

(2) Additionally, the Sea Robin Processing Plant and ET Geismar Olefins have inlet volume capacities of 850 MMcf/d and 54 MMcf/d, respectively.

The following information describes our principal NGL and refined products transportation and services assets:

- The Lone Star Express System is an interstate NGL pipeline consisting of 24-inch and 30-inch long-haul transportation pipeline, with throughput capacity of approximately 900 MBbls/d, that delivers mixed NGLs from processing plants in the Permian Basin, the Barnett Shale, and from East Texas to the Mont Belvieu NGL storage facility.
- The West Texas Gateway Pipeline transports NGLs produced in the Permian and Delaware Basins and the Eagle Ford Shale to Mont Belvieu, Texas and has a throughput capacity of approximately 240 MBbls/d.
- The Mariner East pipeline system, consisting of Mariner East 1 and Mariner East 2, has an aggregate capacity of approximately 345 MMbls/d and transports NGLs from the Marcellus and Utica Shales areas in Western Pennsylvania, West Virginia and Eastern Ohio to destinations in Pennsylvania, including our Marcus Hook Terminal on the Delaware River, where they are processed, stored and distributed to local, domestic and waterborne markets.
- The Mariner South liquids pipeline system consists of three pipelines and delivers export-grade propane, butane and natural gasoline from our Mont Belvieu, Texas storage and fractionation complex to our marine terminal in Nederland, Texas and has a total throughput capacity of approximately 600 MBbls/d.
- The Mariner West pipeline provides transportation of ethane from the Marcellus shale processing and fractionating areas in Houston, Pennsylvania to Marysville, Michigan and the Canadian border and has a throughput capacity of approximately 50 MBbls/d.
- The White Cliffs NGL pipeline, in which we have 51% ownership interest, transports NGLs produced in the DJ Basin to Cushing, where it interconnects with the Southern Hills Pipeline to move NGLs to Mont Belvieu, Texas and has a throughput capacity of approximately 90 MBbls/d.
- Other NGL pipelines include the 127 mile Justice pipeline, the 45 mile Freedom pipeline, the 20 mile Spirit pipeline, a 50% interest in the 87 mile Liberty pipeline, and a 51% interest in the 35 mile Maurepas pipeline.
- Our Mont Belvieu storage facility is an integrated liquids storage facility with approximately 50 MMBbls of salt dome capacity providing 100% fee-based cash flows. The Mont Belvieu storage facility has access to multiple NGL and refined products pipelines, the Houston Ship Channel trading hub, and numerous chemical plants, refineries and fractionators.
- Our Mont Belvieu fractionators handle NGLs delivered from several sources, including the Lone Star Express pipeline and the Justice pipeline.
- Sea Robin is a rich gas processing plant located on the Sea Robin Pipeline in southern Louisiana. The plant is connected to nine interstate and four intrastate residue pipelines, as well as various deep-water production fields.
- ET Geismar Olefins consists of a refinery off-gas processing unit and an O-grade NGL fractionation / Refinery-Grade Propylene ("RGP") splitting complex located along the Mississippi River refinery corridor in southern Louisiana. The off-gas processing unit cryogenically processes refinery off-gas, and the fractionation / RGP splitting complex fractionates the streams into higher value components. The O-grade fractionator and RGP splitting complex, located in Geismar, Louisiana, is connected by approximately 100 miles of pipeline to the Chalmette processing plant, which has a processing capacity of 54 MMcf/d.
- The Hattiesburg storage facility is an integrated liquids storage facility with approximately 5 MMBbls of salt dome capacity, providing 100% fee-based cash flows.
- The Cedar Bayou storage facility is an integrated liquids storage facility with approximately 1.6 MMBbls of tank storage, generating revenues from fixed fee storage contracts, throughput fees, and revenue from blending butane into refined gasoline.
- The Nederland Terminal, in addition to crude oil activities, also provides approximately 1.9 MMBbls of storage and distribution services for NGLs in connection with the Mariner South and Mariner South 2 pipelines, which provide transportation of propane and butane products from the Mont Belvieu region to the Nederland Terminal, where such products can be exported via ship.
- The Orbit Gulf Coast joint venture consists of a 70-mile, 20-inch ethane pipeline with a throughput capacity of approximately 180 MBbls/d, delivering from Lone Star's Mont Belvieu, Texas storage and fractionation complex to our

marine terminal in Nederland, Texas, as well as a 180 MBbls/d ethane refrigeration facility and 1.2 MMBbls of storage capacity.

- The Marcus Hook Terminal includes fractionation, terminalling and storage assets, with a capacity of approximately 2 MMBbls of NGL storage capacity in underground caverns, 4 MMBbls of above-ground refrigerated storage, and related commercial agreements. The terminal has a total active refined products storage capacity of approximately 1 MMBbls. The facility can receive NGLs and refined products via marine vessel, pipeline, truck and rail, and can deliver via marine vessel, pipeline and truck. In addition to providing NGL storage and terminalling services to both affiliates and third-party customers, the Marcus Hook Terminal currently serves as an off-take outlet for our Mariner East 1 and Mariner East 2 pipeline systems.
- The Inkster terminal, located near Detroit, Michigan, consists of multiple salt caverns with a total storage capacity of approximately 860 MBbls of NGLs. We use the Inkster terminal's storage in connection with the Toledo North pipeline system and for the storage of NGLs from local producers and a refinery in Western Ohio. The terminal can receive and ship by pipeline in both directions and has a truck loading and unloading rack.
- The Eastern region refined products pipelines consist of 6-inch to 16-inch diameters refined product pipelines in Eastern, Central and North Central Pennsylvania, 8-inch refined products pipeline in western New York and various diameters refined products pipeline in New Jersey (including 80 miles of the 16-inch diameter Harbor Pipeline).
- The midcontinent region refined products pipelines primarily consist of 3-inch to 12-inch refined products pipelines in Ohio and 6-inch and 8-inch refined products pipeline in Michigan.
- The Southwest region refined products pipelines are located in Eastern Texas and consist primarily of 8-inch and 12-inch diameter refined products pipeline.
- The Inland refined products pipeline consists of 12, 10, 8 and 6-inch diameter pipelines in the western, northwestern, and northeastern regions of Ohio.
- The JC Nolan Pipeline is a joint venture between a wholly-owned subsidiary of the Partnership and a wholly-owned subsidiary of Sunoco LP, which transports diesel fuel from a tank farm in Hebert, Texas to Midland, Texas, and has a throughput capacity of approximately 36 MBbls/d.
- We have 37 refined products terminals with an aggregate storage capacity of approximately 8 MMBbls that facilitate the movement of refined products to or from storage or transportation systems, such as a pipeline, to other transportation systems, such as trucks or other pipelines. Each facility typically consists of multiple storage tanks and is equipped with automated truck loading equipment that is operational 24 hours a day.
- In addition to crude oil service, the Eagle Point terminal can accommodate three marine vessels (ships or barges) to receive and deliver refined products to outbound ships and barges. The tank farm has a total active refined products storage capacity of approximately 7 MMBbls and provides customers with access to the facility via ship, barge and pipeline. The terminal can deliver via ship, barge, truck or pipeline, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage.
- The Marcus Hook Terminal also has a tank farm with total refined products storage capacity of approximately 2 MMBbls of refined products storage. The terminal receives and delivers refined products via pipeline and primarily provides terminalling services to support movements on our refined products pipelines.
- The JC Nolan Terminal, located in Midland, Texas, is a joint venture between a wholly-owned subsidiary of the Partnership and a wholly-owned subsidiary of Sunoco LP, which provides diesel fuel storage.
- This segment also includes the following joint ventures: 15% membership interest in the Explorer Pipeline Company, a 1,850-mile pipeline which originates from refining centers in Beaumont, Port Arthur, and Houston, Texas and extends to Chicago, Illinois; 31% membership interest in the Wolverine Pipe Line Company, a 1,055-mile pipeline that originates from Chicago, Illinois and extends to Detroit, Grand Haven, and Bay City, Michigan; 17% membership interest in the West Shore Pipe Line Company, a 650-mile pipeline which originates in Chicago, Illinois and extends to Madison and Green Bay, Wisconsin; a 14% membership interest in the Yellowstone Pipe Line Company, a 710-mile pipeline which originates from Billings, Montana and extends to Moses Lake, Washington.

Crude Oil Transportation and Services

The following details our pipelines and terminals in its crude oil transportation and services operations:

Description of Assets	Ownership Interest	Miles of Crude Pipeline	Working Storage Capacity (MBbls)
Dakota Access Pipeline	36.40 %	1,170	—
Energy Transfer Crude Oil Pipeline	36.40 %	745	—
Bayou Bridge Pipeline	60 %	210	—
Permian Express Pipelines	87.7 %	1,760	—
Wattenberg Oil Trunkline	100 %	75	360
White Cliffs Pipeline(1)	51 %	530	100
Maurepas Pipeline	51 %	35	—
Other Crude Oil Pipelines	100 %	6,790	—
Nederland Terminal	100 %	—	31,000
Fort Mifflin Terminal	100 %	—	3,300
Eagle Point Terminal	100 %	—	1,800
Midland Terminal	100 %	—	1,000
Marcus Hook Terminal	100 %	—	1,000
Houston Terminal	100 %	—	18,200
Cushing Facility	100 %	—	7,600
Patoka, Illinois Terminal	87.7 %	—	1,900

(1) The White Cliffs Pipeline consists of two parallel, 12-inch common carrier crude oil pipelines: one crude oil pipeline and one NGL pipeline.

Our crude oil operations consist of an integrated set of pipeline, terminalling, trucking and acquisition and marketing assets that service the movement of crude oil from producers to end-user markets. The following details our assets in the crude oil transportation and services segment:

Crude Oil Pipelines

Our crude oil pipelines consist of approximately 11,315 miles of crude oil trunk and gathering pipelines in the southwest, northwest and midwest United States, including our wholly-owned interests in West Texas Gulf, Permian Express Terminal LLC, Mid-Valley and Wattenberg Oil Trunkline. Additionally, we have equity ownership interests in two crude oil pipelines. Our crude oil pipelines provide access to several trading hubs, including the largest trading hub for crude oil in the United States located in Cushing, Oklahoma, and other trading hubs located in Midland, Colorado City and Longview, Texas. Our crude oil pipelines also deliver to and connect with other pipelines that deliver crude oil to a number of refineries.

- *Bakken Pipeline.* The Dakota Access and Energy Transfer Crude Oil pipelines are collectively referred to as the "Bakken Pipeline." The Bakken Pipeline is a 1,915-mile pipeline that transports domestically produced crude oil from the Bakken/Three Forks production areas in North Dakota to a storage and terminal hub outside of Patoka, Illinois, or to gulf coast connections including our crude terminal in Nederland, Texas. In the third quarter 2021, completed that Bakken Optimization project, which increased capacity from 570 MBbls/d to approximately 750 MBbls/d.

  The pipeline transports light, sweet crude oil from North Dakota to major refining markets in the Midwest and Gulf Coast regions.

  The Dakota Access Pipeline consists of approximately 1,170 miles of 12, 20, 24 and 30-inch diameter pipeline traversing North Dakota, South Dakota, Iowa and Illinois. Crude oil transported on the Dakota Access Pipeline originates at six terminal locations in the North Dakota counties of Mountrail, Williams and McKenzie. The pipeline delivers the crude oil to a hub outside of Patoka, Illinois where it can be delivered to the Energy Transfer Crude Oil Pipeline for delivery to the Gulf Coast or can be transported via other pipelines to refining markets throughout the Midwest.

The Energy Transfer Crude Oil Pipeline went into service on June 1, 2017 and consists of approximately 675 miles of mostly 30-inch converted natural gas pipeline and 70 miles of new 30-inch pipeline from Patoka, Illinois to Nederland, Texas, where the crude oil can be refined or further transported to additional refining markets.

- *Bayou Bridge Pipeline.* The Bayou Bridge Pipeline is a joint venture between Energy Transfer and a subsidiary of Phillips 66, in which we have a 60% ownership interest and serves as the operator of the pipeline. Phase I of the pipeline is a 30-inch pipeline from Nederland, Texas to Lake Charles, Louisiana, and Phase II of the pipeline, is a 24-inch pipe from Lake Charles, Louisiana to St. James, Louisiana. Bayou Bridge Pipeline has a capacity of approximately 480 MBbls/d of light and heavy crude oil from different sources to the St. James crude oil hub, which is home to important refineries located in the Gulf Coast region.

- *Permian Express Pipelines.* The Permian Express pipelines are part of the PEP joint venture and include the Permian Express 1, Permian Express 2, Permian Express 3, Permian Express 4, Permian Longview, Louisiana Access, Longview to Louisiana and Nederland Access pipelines. These pipelines are comprised of crude oil trunk pipelines and crude oil gathering pipelines in Texas and Oklahoma and provide takeaway capacity from the Permian Basin, with origins in multiple locations in Western Texas.

- *White Cliffs Pipeline.* White Cliffs Pipeline owns a 12-inch common carrier, crude oil pipeline, with a throughput capacity of 100 MBbls/d, that transports crude oil from Platteville, Colorado to Cushing, Oklahoma.

- *Maurepas Pipeline.* The Maurepas Pipeline consists of three pipelines, with an aggregate throughput capacity of 460 MBbls/d, which service refineries in the Gulf Coast region.

- Other Crude Oil pipelines include the Mid-Valley pipeline system which originates in Longview, Texas and passes through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky and Ohio and terminates in Samaria, Michigan. This pipeline provides crude oil to a number of refineries, primarily in the Midwest United States.

  In addition, we own a crude oil pipeline that runs from Marysville, Michigan to Toledo, Ohio, and a truck injection point for local production at Marysville. This pipeline receives crude oil from the Enbridge pipeline system for delivery to refineries located in Toledo, Ohio and to MPLX's Samaria, Michigan tank farm, which supplies Marathon Petroleum Corporation's refinery in Detroit, Michigan.

  We also own and operate crude oil pipeline and gathering systems in Oklahoma and Kansas. We have the ability to deliver substantially all of the crude oil gathered on our Oklahoma and Kansas systems to Cushing. We are one of the largest purchasers of crude oil from producers in the area and our crude oil acquisition and marketing activities business is the primary shipper on our Oklahoma crude oil system.

  In connection with the Enable Acquisition in December 2021, we acquired crude oil and condensate gathering assets in the Anadarko Basin and the Williston Basin. The Anadarko Basin assets were designed and built to serve the crude oil and condensate production in the SCOOP and STACK plays. A portion of these operations are conducted through Enable South Central Pipeline, a joint venture with a subsidiary of CVR Energy, Inc., which is operated by us and in which we own a 60% membership interest. The Williston Basin crude oil and produced water gathering assets were designed and built to receive crude oil on pipelines near our customers' wells for delivery to third-party transportation pipelines, and produced water gathering pipelines for delivery to third-party disposal wells.

Crude Oil Terminals

- *Nederland.* The Nederland Terminal, located on the Sabine-Neches waterway between Beaumont and Port Arthur, Texas, is a large marine terminal providing storage and distribution services for refiners and other large transporters of crude oil and NGLs. The terminal receives, stores, and distributes crude oil, NGLs, feedstocks, petrochemicals and bunker oils (used for fueling ships and other marine vessels). The terminal currently has a total storage capacity of approximately 31 MMBbls in approximately 150 above ground storage tanks with individual capacities of up to 660 MBbls.

  The Nederland Terminal can receive crude oil at three of its six ship docks and three of its four barge berths. The three ship docks are capable of receiving over 2 MMBbls/d of crude oil. In addition to our crude oil pipelines, the terminal can also receive crude oil through a number of other pipelines, including the DOE. The DOE pipelines connect the terminal to the United States Strategic Petroleum Reserve's West Hackberry caverns at Hackberry, Louisiana and Big Hill caverns near Winnie, Texas, which have an aggregate storage capacity of approximately 395 MMBbls. The terminal also has crude oil rail unloading facilities, including steam availability for heating heavy oils prior to loading.

  The Nederland Terminal can deliver crude oil and other petroleum products via pipeline, barge and ship. The terminal has three ship docks and three barge berths that are capable of delivering crude oils for international transport. In total, the terminal is capable of delivering over 2 MMBbls/d of crude oil to our crude oil pipelines or a number of third-party pipelines including the DOE. The Nederland Terminal generates crude oil revenues primarily by providing term or spot storage services and throughput capabilities to a number of customers.

- *Fort Mifflin.* The Fort Mifflin terminal complex is located on the Delaware River in Philadelphia, Pennsylvania and includes the Fort Mifflin terminal, the Hog Island wharf, the Darby Creek tank farm and connecting pipelines. The Fort Mifflin terminal contains two ship docks with freshwater drafts and a total storage capacity of approximately 570 MBbls. Crude oil and some refined products enter the Fort Mifflin terminal primarily from marine vessels on the Delaware River.

  The Hog Island wharf is located next to the Fort Mifflin terminal on the Delaware River and receives crude oil via two ship docks. The Darby Creek tank farm is a primary crude oil storage terminal that receives crude oil from the Fort Mifflin terminal and Hog Island wharf via our pipelines and has a total storage capacity of approximately 2.7 MMBbls.

- *Eagle Point.* The Eagle Point terminal is located in Westville, New Jersey and consists of docks, truck loading facilities and a tank farm. The docks are located on the Delaware River and can accommodate three marine vessels (ships or barges) to receive and deliver crude oil, intermediate products and refined products to outbound ships and barges. The tank farm has a total active storage capacity of approximately 1.8 MMBbls and can receive crude oil via barge and rail and deliver via ship and barge, providing customers with access to various markets. The terminal generates revenue primarily by charging fees based on throughput, blending services and storage.

- *Midland.* The Midland terminal is located in Midland, Texas and includes approximately 1 MMBbls of crude oil storage, a combined 20 lanes of truck loading and unloading, and provides access to the Permian Express 2 transportation system.

- *Marcus Hook Terminal.* The Marcus Hook Terminal can receive crude oil via marine vessel and can deliver via marine vessel and pipeline. The terminal has a total active crude oil storage capacity of approximately 1 MMBbls.

- *Patoka, Illinois Terminal.* The Patoka, Illinois terminal is a tank farm owned by the PEP joint venture and is located in Marion County, Illinois. The facility includes 234 acres of owned land and provides for approximately 1.9 MMBbls of crude oil storage.

- *Houston Terminal.* The Houston Terminal consists of storage tanks located on the Houston Ship Channel with an aggregate storage capacity of 18.2 MMBbls used to store, blend and transport refinery products and refinery feedstocks via pipeline, barge, rail, truck and ship. This facility has five deep-water ship docks on the Houston Ship Channel capable of loading and unloading Suezmax cargo vessels and seven barge docks which can accommodate 23 barges simultaneously, three crude oil pipelines connecting to four refineries and numerous rail and truck loading spots.

- *Cushing Facilities.* The Cushing Facility has approximately 7.6 MMBbls of crude oil storage, of which 5.6 MMBbls are leased to customers and 2.0 MMBbls are available for crude oil operations, blending and marketing activities. The storage terminal has inbound connections with the White Cliffs Pipeline from Platteville, Colorado, the Great Salt Plains Pipeline from Cherokee, Oklahoma, the Cimarron Pipeline from Boyer, Kansas, and two-way connections with all of the other major storage terminals in Cushing. The Cushing terminal also includes truck unloading facilities.

Crude Oil Acquisition and Marketing

Our crude oil acquisition and marketing operations are conducted using our assets, which include approximately 363 crude oil transport trucks, 350 trailers and approximately 166 crude oil truck unloading facilities, as well as third-party truck, rail, pipeline and marine assets.

Investment in Sunoco LP

Sunoco LP’s fuel distribution and marketing operations are conducted by the following consolidated subsidiaries:

- Sunoco, LLC (“Sunoco LLC”), a Delaware limited liability company, primarily distributes motor fuel in approximately 40 states. Sunoco LLC also processes transmix and distributes refined product through its terminals in Alabama, Arkansas, Florida, Illinois, New Jersey, New York, Texas, and Virginia;

- Sunoco Retail LLC (formerly Sunoco Property Company LLC) (“Sunoco Retail”), a Pennsylvania limited liability company, owns and operates retail stores that sell motor fuel and merchandise primarily in New Jersey. Sunoco Retail also leases owned sites to commissioned agents who sell motor fuels to the motoring public on Sunoco Retail’s behalf for a commission;

- Aloha Petroleum LLC, a Delaware limited liability company, distributes motor fuel and operates terminal facilities on the Hawaiian Islands; and

- Aloha Petroleum, Ltd. (“Aloha”), a Hawaii corporation, owns and operates retail stores on the Hawaiian Islands.

Sunoco LP purchases motor fuel primarily from independent refiners and major oil companies and distributes it throughout the East Coast, Midwest, South Central and Southeast regions of the United States, as well as Hawaii to approximately:

- 78 company owned and operated retail stores;
- 540 independently operated commission agent locations where Sunoco LP sells motor fuel to customers under commission agent arrangements with such operators;
- 6,741 retail stores operated by independent operators, which are referred to as "dealers" or "distributors," pursuant to long-term distribution agreements; and
- 2,424 other commercial customers, including unbranded retail stores, other fuel distributors, school districts and municipalities and other industrial customers.

Sunoco LP's operations also include retail operations in Hawaii and New Jersey, credit card services and franchise royalties.

Investment in USAC

The following details the assets of USAC:

USAC's modern, standardized compression unit fleet is powered primarily by the Caterpillar, Inc.'s 3400, 3500 and 3600 engine classes, which range from 401 to 5,000 horsepower per unit. These larger horsepower units, which USAC defines as 400 horsepower per unit or greater, represented 86.3% of its total fleet horsepower as of December 31, 2021. The remainder of its fleet consists of smaller horsepower units ranging from 40 horsepower to 399 horsepower that are primarily used in gas lift applications.

The following table provides a summary of USAC's compression units by horsepower as of December 31, 2021:

Unit Horsepower	Fleet Horsepower	Number of Units	Horsepower on Order (1)	Number of Units on Order	Total Horsepower	Number of Units	Percent of Fleet Horsepower	Percent of Units
Small horsepower								
<400	508,496	2,991	—	—	508,496	2,991	13.7 %	55.2 %
Large horsepower								
>400 and <1,000	430,677	736	—	—	430,677	736	11.6 %	13.6 %
>1,000	2,749,845	1,684	25,000	10	2,774,845	1,694	74.7 %	31.2 %
Total large horsepower	3,180,522	2,420	25,000	10	3,205,522	2,430	86.3 %	44.8 %
Total horsepower	3,689,018	5,411	25,000	10	3,714,018	5,421	100.0 %	100.0 %

(1) As of December 31, 2021, USAC had 10 large horsepower units, consisting of 25,000 horsepower, on order for delivery during 2022.

All Other

The following details the significant assets in the "All Other" segment.

Contract Services Operations

We own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and Btu management. Our contract treating services are primarily located in Texas, Louisiana and Arkansas.

Compression

We own DDT, which provides compression services to customers engaged in the transportation of natural gas, including our other segments.

Natural Resources Operations

Our Natural Resources operations primarily involve the management and leasing of coal properties and the subsequent collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage fees. As of December 31, 2021, we owned or controlled approximately 736 million tons of proven and probable coal reserves in central and northern Appalachia, properties in eastern Kentucky, southwestern Virginia and southern West Virginia, and in the Illinois Basin, properties in southern Illinois, Indiana, and western Kentucky and as the operator of end-user coal handling facilities.

Canadian Operations

Our Canadian operations include a 51% ownership interest in Energy Transfer Canada which owns and operates natural gas processing and gathering facilities in Alberta, Canada. The Canadian operations assets include four sour natural gas processing plants and two sweet natural gas processing plants that have a combined operating capacity of 1,290 MMcf/d and a network of approximately 848 miles of natural gas gathering and transportation pipelines. The principal process performed at the processing plants is to remove contaminants and render the gas salable to downstream pipelines and markets.

Business Strategy

We believe we have engaged, and will continue to engage, in a well-balanced plan for growth through strategic acquisitions, internally generated expansion, measures aimed at increasing the profitability of our existing assets and executing cost control measures where appropriate to manage our operations.

We intend to continue to operate as a diversified, growth-oriented limited partnership. We believe that by pursuing independent operating and growth strategies we will be best positioned to achieve our objectives. We balance our desire for growth with our goal of preserving a strong balance sheet, ample liquidity and investment grade credit metrics.

Following is a summary of the business strategies of our core businesses:

Growth through acquisitions. We intend to continue to make strategic acquisitions that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of our existing assets while supporting our investment grade credit ratings.

Engage in construction and expansion opportunities. We intend to leverage our existing infrastructure and customer relationships by constructing and expanding systems to meet new or increased demand for midstream and transportation services.

Increase cash flow from fee-based businesses. We intend to increase the percentage of our business conducted with third parties under fee-based arrangements in order to provide for stable, consistent cash flows over long contract periods while reducing exposure to changes in commodity prices.

Enhance profitability of existing assets. We intend to increase the profitability of our existing asset base by adding new volumes under long-term producer commitments, undertaking additional initiatives to enhance utilization and reducing costs by improving operations.

Competition

Natural Gas

The business of providing natural gas gathering, compression, treating, transportation, storage and marketing services is highly competitive. Since pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our transportation and storage segment are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability.

We face competition with respect to retaining and obtaining significant natural gas supplies under terms favorable to us for the gathering, treating and marketing portions of our business. Our competitors include major integrated oil and gas companies, interstate and intrastate pipelines and other companies that gather, compress, treat, process, transport and market natural gas. Many of our competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours.

In marketing natural gas, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.

NGL

In markets served by our NGL pipelines, we face competition with other pipeline companies, including those affiliated with major oil, petrochemical and natural gas companies, and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees, reliability and quality of customer service. We face competition with other storage facilities based on fees charged and the ability to receive and distribute the customer's products. We compete with a number of NGL fractionators in Texas and Louisiana. Competition for such services is primarily based on the fractionation fee charged.

Crude Oil and Refined Products

In markets served by our crude oil and refined products pipelines, we face competition from other pipelines as well as rail and truck transportation. Generally, pipelines are the safest, lowest cost method for long-haul, overland movement of products and crude oil. Therefore, the most significant competitors for large volume shipments in the areas served by our pipelines are other pipelines. In addition, pipeline operations face competition from rail and trucks that deliver products in a number of areas that our pipeline operations serve. While their costs may not be competitive for longer hauls or large volume shipments, rail and trucks compete effectively for incremental and marginal volume in many areas served by our pipelines.

With respect to competition from other pipelines, the primary competitive factors consist of transportation charges, access to crude oil supply and market demand. Competitive factors in crude oil purchasing and marketing include price and contract flexibility, quantity and quality of services, and accessibility to end markets.

Our refined product terminals compete with other independent terminals with respect to price, versatility and services provided. The competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

Wholesale Fuel Distribution and Retail Marketing

In our wholesale fuel distribution business, we compete primarily with other independent motor fuel distributors. The markets for distribution of wholesale motor fuel and the large and growing convenience store industry are highly competitive and fragmented, which results in narrow margins. We have numerous competitors, some of which may have significantly greater resources and name recognition than we do. Significant competitive factors include the availability of major brands, customer service, price, range of services offered and quality of service, among others. We rely on our ability to provide value-added and reliable service and to control our operating costs in order to maintain our margins and competitive position.

In our retail business, we face strong competition in the market for the sale of retail gasoline and merchandise. Our competitors include service stations of large integrated oil companies, independent gasoline service stations, convenience stores, fast food stores, supermarkets, drugstores, dollar stores, club stores and other similar retail outlets, some of which are well-recognized national or regional retail systems. The number of competitors varies depending on the geographical area. It also varies with gasoline and convenience store offerings. The principal competitive factors affecting our retail marketing operations include gasoline and diesel acquisition costs, site location, product price, selection and quality, site appearance and cleanliness, hours of operation, store safety, customer loyalty and brand recognition. We compete by pricing gasoline competitively, combining our retail gasoline business with convenience stores that provide a wide variety of products, and using advertising and promotional campaigns.

Credit Risk and Customers

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

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

During the year ended December 31, 2021, none of our customers individually accounted for more than 10% of our consolidated revenues.

Regulation

Regulation of Interstate Natural Gas Pipelines. The FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines. Under the NGA, the FERC generally regulates the transportation of natural gas in interstate commerce. For FERC regulatory purposes, "transportation" includes natural gas pipeline transmission (forwardhauls and backhauls), storage and other services. FGT, Transwestern, Panhandle, Trunkline, ETC Tiger, Fayetteville Express, Rover, Sea Robin, Midcontinent Express, Enable Gas Transmission, LLC, Enable Mississippi River Transmission, LLC, Southeast Supply Header, Stingray, Southwest Gas, and ETC Texas transport natural gas in interstate commerce and thus each qualifies as a "natural-gas company" under the NGA subject to the FERC's regulatory jurisdiction. We also hold certain natural gas storage facilities that are subject to the FERC's regulatory oversight under the NGA.

The FERC's NGA authority includes the power to:

- approve the siting, construction and operation of new facilities;
- review and approve transportation rates;
- determine the types of services our regulated assets are permitted to perform;
- regulate the terms and conditions associated with these services;
- permit the extension or abandonment of services and facilities;
- require the maintenance of accounts and records; and
- authorize the acquisition and disposition of facilities.

Under the NGA, interstate natural gas companies must charge rates that are just and reasonable. In addition, the NGA prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The maximum rates to be charged by NGA-jurisdictional natural gas companies and their terms and conditions for service are required to be on file with the FERC. Most natural gas companies are authorized to offer discounts from their FERC-approved maximum just and reasonable rates when competition warrants such discounts. Natural gas companies are also generally permitted to offer negotiated rates different from rates established in their tariff if, among other requirements, such companies' tariffs offer a cost-based recourse rate to a prospective shipper as an alternative to the negotiated rate. Natural gas companies must make offers of rate discounts and negotiated rates on a basis that is not unduly discriminatory. Existing tariff rates may be challenged by complaint or on the FERC's own motion, and if found unjust and unreasonable, may be altered on a prospective basis from no earlier than the date of the complaint or initiation of a proceeding by the FERC. The FERC must also approve all rate changes. We cannot guarantee that the FERC will allow us to charge rates that fully recover our costs or continue to pursue its approach of pro-competitive policies.

For two of our NGA-jurisdictional natural gas companies, ETC Tiger and FEP, the large majority of capacity in those pipelines is subscribed for lengthy terms under FERC-approved negotiated rates. However, as indicated above, cost-based recourse rates are also offered under their respective tariffs.

Pursuant to the FERC's rules promulgated under the Energy Policy Act of 2005, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction: (i) to defraud using any device, scheme or artifice; (ii) to make any untrue statement of material fact or omit a material fact; or (iii) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit. The Commodity Futures Trading Commission ("CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act ("CEA"). With regard to our physical purchases and sales of natural gas, NGLs or other energy commodities; our transportation of these energy commodities; and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess or seek civil penalties of up to $1.3 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Failure to comply with the NGA, the Energy Policy Act of 2005, the CEA and the other federal laws and regulations governing our operations and business activities can result in the imposition of administrative, civil and criminal remedies.

Regulation of Intrastate Natural Gas and NGL Pipelines. Intrastate transportation of natural gas and NGLs is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce, the rates and terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the NGPA. The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates and terms and conditions of some transportation and storage services provided on Enable Oklahoma Intrastate Transmission, Oasis pipeline, HPL System, East Texas pipeline, ET Fuel System, Trans-Pecos pipeline and Comanche Trail pipeline are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved statement of operating conditions could result in an alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

Our intrastate natural gas operations are also subject to regulation by various agencies in Texas, principally the TRRC. Our intrastate pipeline and storage operations in Texas are also subject to the Texas Utilities Code, as implemented by the TRRC. Generally, the TRRC is vested with authority to ensure that rates, operations and services of gas utilities, including intrastate pipelines, are just and reasonable and not discriminatory. The rates we charge for transportation services are deemed just and reasonable under Texas law unless challenged in a customer or TRRC complaint. We cannot predict whether such a complaint will be filed against us or whether the TRRC will change its regulation of these rates. Failure to comply with the Texas Utilities Code can result in the imposition of administrative, civil and criminal remedies.

Our NGL pipelines and operations are subject to state statutes and regulations which could impose additional environmental, safety and operational requirements relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL transportation systems. In some jurisdictions, state public utility commission oversight may include the possibility of fines, penalties and delays in construction related to these regulations. In addition, the rates, terms and conditions of service for shipments of NGLs on our pipelines are subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 (the "EPAct of 1992") if the NGLs are transported in interstate or foreign commerce whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all NGLs shipped on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

Regulation of Sales of Natural Gas and NGLs. The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The price at which we sell NGLs is not subject to federal or state regulation.

To the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to the use of such capacity. Any failure on our part to comply with the FERC's regulations and policies, or with an interstate pipeline's tariff, could result in the imposition of civil and criminal penalties.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC frequently proposes and implements new rules and regulations affecting those segments of the natural gas industry. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC's regulatory changes may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action in a manner that is materially different from other natural gas marketers with whom we compete.

Regulation of Gathering Pipelines. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own a number of natural gas pipelines in Texas, Louisiana and West Virginia that we believe meet the traditional tests the FERC uses to establish a pipeline's status as a gathering pipeline not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and varying interpretations, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by the FERC, the courts and Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

In Texas, our gathering facilities are subject to regulation by the TRRC under the Texas Utilities Code in the same manner as described above for our intrastate pipeline facilities. Louisiana's Pipeline Operations Section of the Department of Natural Resources' Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities.

Historically, apart from pipeline safety, Louisiana has not acted to exercise this jurisdiction respecting gathering facilities. In Louisiana, our Chalkley System is regulated as an intrastate transporter, and the Louisiana Office of Conservation has determined that our Whiskey Bay System is a gathering system.

We are subject to state ratable take and common purchaser statutes in all of the states in which we operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting the right of an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. For example, the TRRC has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination allegations. Our gathering operations could be adversely affected should they be subject in the future to the application of additional or different state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Regulation of Interstate Crude Oil, NGL and Products Pipelines. Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the ICA, the EPAct of 1992, and related rules and orders. The ICA requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory and that such rates and terms and conditions of service be filed with the FERC. This statute also permits interested persons to challenge proposed new or changed rates. The FERC is authorized to suspend the effectiveness of such rates for up to seven months, though rates are typically not suspended for the maximum allowable period. If the FERC finds that the new or changed rate is unlawful, it may require the carrier to pay refunds for the period that the rate was in effect. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The FERC generally has not investigated interstate rates on its own initiative when those rates, like those we charge, have not been the subject of a protest or a complaint by a shipper. However, the FERC could investigate our rates at the urging of a third party if the third party is either a current shipper or has a substantial economic interest in the tariff rate level. Although no assurance can be given that the tariff rates charged by us ultimately will be upheld if challenged, management believes that the tariff rates now in effect for our pipelines are within the maximum rates allowed under current FERC policies and precedents.

For many locations served by our product and crude pipelines, we are able to establish negotiated rates. Otherwise, we are permitted to charge cost-based rates, or in many cases, grandfathered rates based on historical charges or settlements with our customers. To the extent we rely on cost-of-service ratemaking to establish or support our rates, the issue of the proper allowance for federal and state income taxes could arise. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued an opinion in United Airlines, Inc., et al. v. FERC, finding that the FERC had failed to demonstrate that permitting an interstate petroleum products pipeline organized as a master limited partnership, or MLP, to include an income tax allowance in the cost of service underlying its rates, in addition to the discounted cash flow return on equity, would not result in the pipeline partnership owners double recovering their income taxes. The court vacated the FERC's order and remanded to the FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance.

In March 2018, the FERC issued a Revised Policy Statement on Treatment of Income Taxes in which the FERC found that an impermissible double recovery results from granting an MLP pipeline both an income tax allowance and a return on equity pursuant to the FERC's discounted cash flow methodology. The FERC revised its previous policy, stating that it would no longer permit an MLP pipeline to recover an income tax allowance in its cost of service. The FERC stated it will address the application of the United Airlines decision to non-MLP partnership forms as those issues arise in subsequent proceedings. In July 2018, the FERC dismissed requests for rehearing and clarification of the March 2018 Revised Policy Statement, but provided further guidance, clarifying that a pass-through entity 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 FERC's March 2018 Revised Policy Statement, as clarified and revised on rehearing. In light of the rehearing order's clarification regarding individual entities' 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 impacts the FERC's policy on the treatment of income taxes may have on the rates an interstate pipeline held in a tax-pass-through entity can charge for the FERC regulated transportation services are unknown at this time. Please see "Item 1A. Risk Factors - Regulatory Matters."

Effective January 2018, the 2017 Tax Cuts and Jobs Act changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. With the lower tax rate, and as discussed immediately above, the maximum tariff rates allowed by the FERC under its rate base methodology may be impacted by a lower income tax allowance component. Many of our interstate pipelines, such as 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, and the rate base methodology does not apply directly to these contracts. Other systems, such as FGT, Transwestern and Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. In addition, several of these pipelines are covered by approved settlements, pursuant to which rate filings will be made in the future. As such, the timing and impact to these systems of any tax-related policy change is unknown at this time and varies based on the circumstances of each pipeline.

The EPAct of 1992 required the FERC to establish a simplified and generally applicable methodology to adjust tariff rates for inflation for interstate petroleum pipelines. As a result, the FERC adopted 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. The FERC's indexing methodology is subject to review every five years.

In December 2020, FERC issued an order setting the indexed rate at PPI-FG plus 0.78% during the five-year period commencing July 1, 2021 and ending June 30, 2026. The Commission received requests for rehearing of its December 17, 2020 order and on January 20, 2022, granted rehearing and modified the oil index. Specifically, for the five-year period commencing July 1, 2021 and ending June 30, 2026, FERC-regulated liquids pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI-FG minus 0.21%. FERC directed liquids pipelines to recompute their ceiling levels for July 1, 2021 through June 30, 2022 based on the new index level. Where an oil pipeline's filed rates exceed its ceiling levels, FERC ordered such oil pipelines to reduce the rate to bring it into compliance with the recomputed ceiling level to be effective March 1, 2022. The indexing methodology is applicable to existing rates, including grandfathered rates, with the exclusion of market-based rates. A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so and rate increases made under the index are presumed to be just and reasonable unless a protesting party can demonstrate that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. Under the indexing rate methodology, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling.

Finally, in November 2017, the FERC responded to a petition for declaratory order and issued an order that may have significant impacts on the way a marketer of crude oil or petroleum products that is affiliated with an interstate pipeline can price its services if those services include transportation on an affiliate's interstate pipeline. In particular, the FERC's November 2017 order prohibits buy/sell arrangements by a marketing affiliate if: (i) the transportation differential applicable to its affiliate's interstate pipeline transportation service is at a discount to the affiliated pipeline's filed rate for that service; and (ii) the pipeline affiliate subsidizes the loss. Several parties have requested that the FERC clarify its November 2017 order or, in the alternative, grant rehearing of the November 2017 order. The FERC extended the time frame to respond to such requests in January 2018 but has not yet taken final action. We are unable to predict how the FERC will respond to such requests. Depending on how the FERC responds, it could have an impact on the rates we are permitted to charge.

Regulation of Intrastate Crude Oil, NGL and Products Pipelines. Some of our crude oil, NGL and products pipelines are subject to regulation by the TRRC, the Pennsylvania Public Utility Commission and the Oklahoma Corporation Commission. The operations of our joint venture interests are also subject to regulation in the states in which they operate. The applicable state statutes require that pipeline rates be nondiscriminatory and provide no more than a fair return on the aggregate value of the pipeline property used to render services. State commissions generally have not initiated an investigation of rates or practices of petroleum pipelines in the absence of shipper complaints. Complaints to state agencies have been infrequent and are usually resolved informally. Although management cannot be certain that our intrastate rates ultimately would be upheld if challenged, we believe that, given this history, the tariffs now in effect are not likely to be challenged or, if challenged, are not likely to be ordered to be reduced.

In addition, as noted above, the rates, terms and conditions for shipments of crude oil, NGLs or products on our pipelines could be subject to regulation by the FERC under the ICA and the EPAct of 1992 if the crude oil, NGLs or products are transported in interstate or foreign commerce whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all crude oil, NGLs or products shipped on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

Regulation of Pipeline Safety. Our pipeline operations are subject to regulation by the DOT, through PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas, which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Failure to comply with the pipeline safety laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays in permitting or the performance of projects, or the issuance of injunctions limiting or prohibiting some or all of our operations in the affected area.

The HLPSA and NGPSA have been amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016. The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2011 Pipeline Safety Act doubled the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1 million to $2 million for a related series of violations, but provided that these maximum penalty caps do not apply to certain civil enforcement actions. In May 2021, PHMSA issued a final rule increasing those maximum civil penalties to $225,134 per day, with a maximum of $2,251,334 for a series of violations, to account for inflation. Upon reauthorization of PHMSA, Congress often directs the agency to complete certain rulemakings. For example, in the Consolidated Appropriations Bill for Fiscal Year 2021, Congress reauthorized PHMSA through fiscal year 2023 and directed the agency to move forward with several regulatory actions, including the "Pipeline Safety: Class Location Change Requirements" and the "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" proposed rulemaking. To that end, in November 2021, PHMSA issued a final rule significantly expanding reporting and safety requirements of operators of gas gathering pipelines. The rule imposes safety regulations on approximately 400,000 miles of previously unregulated onshore gas gathering lines that, among other things, will impose criteria for inspection and repair of fugitive emissions, extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. Additionally, in June 2021, PHMSA issued an Advisory Bulletin advising pipeline and pipeline facility operators of applicable requirements to update their inspection and maintenance plans for the elimination of hazardous leaks and minimization of natural gas from related pipeline facilities. PHMSA, together with state regulators, are expected to commence and complete inspection of these plans in 2022.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. The states in which we conduct operations typically have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines. Under such state regulatory programs, states have the authority to conduct pipeline inspections, to investigate accidents and to oversee compliance and enforcement, safety programs and record maintenance and reporting. Congress, PHMSA and individual states may pass or implement additional safety requirements that could result in increased compliance costs for us and other companies in our industry. For example, federal construction, maintenance and inspection standards under the NGPSA that apply to pipelines in relatively populated areas may not apply to gathering lines running through rural regions. However, in October 2019, PHMSA published two further final rules, in addition to the November 2021 rule discussed above, that create or expand reporting, inspection, maintenance, and other pipeline safety obligations, including, among other things, extending pipeline integrity assessments to pipelines in certain locations, including newly-defined "Moderate Consequence Areas" ("MCAs"). Specifically, PHMSA issued a final rule imposing numerous requirements on onshore gas transmission pipelines relating to maximum allowable operating pressure ("MAOP"), reconfirmation and exceedance reporting, the integrity assessment of additional pipeline mileage found in MCAs, non-High Consequence Area ("HCAs"), and Class 3 and Class 4 areas by 2023, and the consideration of seismicity as a risk factor in integrity management. Establishing MAOP through reliance on historical pipeline design, construction, inspection, testing, and other records requires that such records be traceable, verifiable, and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing (including hydrotesting) or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. Failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. PHMSA's second final rule, published in October 2019, applicable to hazardous liquid transmission and gathering pipelines, significantly extended and expanded the reach of certain integrity management requirements, use of in-line inspection tools by 2039 (unless the pipeline cannot be modified to permit such use), increased annual, accident, and safety-related conditional reporting requirements, and expanded use of leak detection systems beyond HCAs. The integrity-related requirements and other provisions of the 2011 Pipeline Safety Act, the 2016 Pipeline Safety Act, and the PIPES Act of 2020, as well as any implementation of PHMSA rules thereunder, could require us to pursue additional capital projects or conduct integrity or maintenance programs on an accelerated basis and incur increased operating costs that could have a material adverse effect on our results of operations and financial condition.

In another example of how future legal requirements could result in increased compliance costs, notwithstanding the applicability of the federal OSHA's Process Safety Management ("PSM") regulations and the EPA's Risk Management Planning ("RMP") requirements at regulated facilities, PHMSA and one or more state regulators, including the TRRC, have in recent years, expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid pipeline safety requirements. To the extent that these actions are pursued by PHMSA, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current PSM and RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Environmental Matters

General. Our operation of processing plants, pipelines and associated facilities, including compression, in connection with the gathering, processing, storage and transmission of natural gas and the storage and transportation of NGLs, crude oil and refined products is subject to stringent U.S. federal, tribal, state and local laws and regulations, including those governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Similar or more stringent laws also exist in Canada. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and criminal sanctions, third-party claims for personal injury or property damage, capital expenditures to retrofit or upgrade our facilities and programs, or curtailment or cancellation of permits on operations. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall cost of doing business, including our cost of planning, permitting, constructing and operating our plants, pipelines and other facilities. As a result of these laws and regulations, our construction and operation costs include capital, operating and maintenance cost items necessary to maintain or upgrade our equipment and facilities.

We have implemented procedures designed to ensure that governmental environmental approvals for both existing operations and those under construction are updated as circumstances require. Historically, our environmental compliance costs have not had a material adverse effect on our business, results of operations or financial condition; however, there can be no assurance that such costs will not be material in the future. For example, we cannot be certain that identification of presently unidentified conditions, more rigorous enforcement by regulatory agencies, enactment of more stringent environmental laws and regulations or unanticipated events will not arise in the future and give rise to environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

Uncertainty about the future course of regulation continues to exist following the change in U.S. presidential administrations in January 2021. Upon taking office, the Biden Administration issued an executive order directing all federal agencies to review and take action to address any federal regulations promulgated during the prior administration that may be inconsistent with the current administration's policies. As a result, several regulatory developments have occurred, but it remains unclear the degree to which this will continue. The executive order also established an Interagency Working Group on the Social Cost of Greenhouse Gases ("Working Group"), which is called on to, among other things, develop methodologies for calculating the "social cost of carbon," "social cost of nitrous oxide" and "social cost of methane." During 2021, the Working Group published interim estimates of the social costs of carbon, methane, and nitrous oxide and sought public comment on these estimates. The Working Group's final recommendations are expected in early 2022. Further regulation of air emissions, as well as uncertainty regarding the future course of regulation, could eventually reduce the demand for oil and natural gas and, in turn, have a material adverse effect on our business, financial condition or results of operations.

Hazardous Substances and Waste Materials. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances and waste materials into soils, groundwater and surface water and include measures to prevent, minimize or remediate contamination of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of hazardous substances and waste materials and may require investigatory and remedial actions at sites where such material has been released or disposed. For example, the Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. These persons include the owner and operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substance that has been released into the environment. Under CERCLA, these persons may be subject to strict, joint and several liability, without regard to fault, for, among other things, the costs of investigating and remediating the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and comparable state law also authorize the federal EPA, its state counterparts, and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Although "petroleum" as well as natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations we generate wastes that may fall within that definition or that may be subject to other waste disposal laws and regulations. We may be responsible under CERCLA or state laws for all or part of the costs required to clean up sites at which such substances or wastes have been disposed.

We also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, as amended, ("RCRA") and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA hazardous waste requirements at many of our facilities because the minimal quantities of hazardous wastes generated there make us subject to less stringent non-hazardous management standards. From time to time, the EPA has considered or third parties have petitioned the agency on the adoption of stricter handling, storage and disposal standards for nonhazardous wastes, including certain wastes associated with the exploration, development and production of crude oil and natural gas. For example, in 2016, the EPA entered into an agreement with several environmental groups to analyze certain Subtitle D criteria regulations pertaining to oil and gas wastes and, if necessary, revise them. In response to the decree, in April 2019, the EPA signed a determination that revision of the regulations is not necessary at this time. It is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes such as these examples in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense and, in the case of our oil and natural gas exploration and production customers, could result in increased operating costs for those customers and a corresponding decrease in demand for our processing, transportation and storage services.

We currently own or lease sites that have been used over the years by prior owners and lessees and by us for various activities related to gathering, processing, storage and transmission of natural gas, NGLs, crude oil and refined products. Waste disposal practices within the oil and gas industry have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and wastes have been disposed of or otherwise released on or under various sites during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these releases may have occurred during the ownership or operation of these assets by others, these sites may be subject to CERCLA, RCRA and comparable state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or contamination (including soil and groundwater contamination) or to prevent the migration of contamination.

As of December 31, 2021 and 2020, accruals of $293 million and $306 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover estimated material environmental liabilities.

The Partnership is subject to extensive and frequently changing federal, tribal, state and local laws and regulations, including those relating to the discharge of materials into the environment or that otherwise relate to the protection of the environment, waste management and the characteristics and composition of fuels. These laws and regulations require environmental assessment and remediation efforts at many of ETC Sunoco's facilities and at formerly owned or third-party sites. Accruals for these environmental remediation activities amounted to $234 million and $247 million at December 31, 2021 and 2020, respectively, which is included in the total accruals above. These legacy sites that are subject to environmental assessments include formerly owned terminals and other logistics assets, retail sites that are no longer operated by ETC Sunoco, closed and/or sold refineries and other formerly owned sites. We have established a wholly-owned captive insurance company for these legacy 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. As of December 31, 2021, the captive insurance company held $175 million of cash and investments.

The Partnership's accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual for known claims is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs, and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for environmental remediation activities.

Under various environmental laws, including the RCRA, the Partnership has initiated corrective remedial action at certain of its facilities, formerly owned facilities and at certain third-party sites. At the Partnership's major manufacturing facilities, we have typically assumed continued industrial use and a containment/remediation strategy focused on eliminating unacceptable risks to human health or the environment. The remediation accruals for these sites reflect that strategy. Accruals include amounts designed to prevent or mitigate off-site migration and to contain the impact on the facility property, as well as to address known, discrete areas requiring remediation within the plants. Remedial activities include, for example, closure of RCRA waste management units, recovery of hydrocarbons, handling of impacted soil, mitigation of surface water impacts and prevention or mitigation of off-site migration. A change in this approach as a result of changing the intended use of a property or a sale to a third party could result in a comparatively higher cost remediation strategy in the future.

In general, a remediation site or issue is typically evaluated on an individual basis based upon information available for the site or issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (for example, service station sites) in determining the amount of probable loss accrual to be recorded. The estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance allows us the minimum amount of the range to accrue. Accordingly, the low end of the range often represents the amount of loss which has been recorded. The Partnership's consolidated balance sheet reflected $293 million in environmental accruals as of December 31, 2021.

In summary, total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years, but management can provide no assurance that it would be over many years. If changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could materially and adversely impact multiple facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur. And while management does not believe that any such charges would have a material adverse impact on the Partnership's consolidated financial position, it can provide no assurance.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by PCBs, and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2025 is $3 million, which is included in the total environmental accruals mentioned above. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007. Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCB contamination. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. Such future costs are not expected to have a material impact on our financial position, results of operations or cash flows, but management can provide no assurance.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, such as our processing plants and compression facilities, expected to produce air emissions or to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. We will incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. In addition, our processing plants, pipelines and compression facilities are subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. Historically, our costs for compliance with existing Clean Air Act and comparable state law requirements have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future. The EPA and state agencies are often considering, proposing or finalizing new regulations that could impact our existing operations and the costs and timing of new infrastructure development. For example, in October 2015, the EPA published a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA completed attainment/non-attainment designations in 2018, and states with moderate or high non-attainment areas must submit state implementation plans to the EPA by October 2021. By law, the EPA must review each NAAQS every five years. In December 2020, the EPA announced that it was retaining without revision the 2015 NAAQS for ozone. However, the Biden Administration has announced plans to formally review this decision and consider instituting a more stringent standard. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our customers' operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended, ("Clean Water Act") and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including hydrocarbon-bearing wastes, into state waters and waters of the United States. Pursuant to the Clean Water Act and similar state laws, a National Pollutant Discharge Elimination System, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In June 2015, the EPA and the USACE published a final rule attempting to clarify the federal jurisdictional reach over "waters of the United States" ("WOTUS"), but legal challenges to this rule followed. In January 2020, a new "waters of the United States" rule was finalized to replace the June 2015 rule, defining the following four categories of waters as WOTUS: traditional navigable waters and territorial seas; perennial and intermittent tributaries to those waters; lakes, ponds and impoundments of jurisdictional waters; and wetlands adjacent to jurisdictional waters. However, both the 2015 and 2020 rulemakings have been subject to legal challenges, and the Biden Administration has announced plans to establish its own definition of WOTUS. Most recently, the EPA and USACE published a proposed rulemaking to revoke the 2020 rule in favor of a pre-2015 definition until a new definition is proposed, which the Biden Administration has announced is underway. As a result of these developments, the scope of jurisdiction under the Clean Water Act is uncertain at this time, but to the extent any rule expands the scope of the Clean Water Act's jurisdiction, our operations as well as our exploration and production customers' drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Additionally, for over 35 years, the USACE has authorized construction, maintenance, and repair of pipelines under a streamlined Nationwide Permit ("NWP") program. From time to time, environmental groups have challenged the NWP program, and, in April 2020, the U.S. District Court for the District of Montana determined that NWP 12 failed to comply with consultation requirements under the federal Endangered Species Act. The district court vacated NWP 12 and enjoined the issuance of new authorizations for oil and gas pipeline projects under the permit. In January 2021, the EPA and USACE issued a final rule reissuing and restricting NWP 12 to oil and gas pipelines and creating a new nationwide permit to authorize certain dredge and fill activities associated with utility lines conveying other substances such as brine, potable water, wastewater, and other substances excluding oil, natural gas, products derived from oil or natural gas, and electricity. The Biden Administration was asked to examine the final rule. Additionally, an October 2021 decision by the District Court for the Northern District of California resulted in the vacatur of a 2020 rule revising the Clean Water Act Section 401 certification process, following which, in November 2021, USACE announced that it has temporarily suspended finalization of certain permitting decisions, including under NWP 12, that rely on a Section 401 certification or waiver under the 2020 rule. While the full extent and impact of these vacaturs and any future revisions to NWP 12 by the Biden Administration is unclear at this time, we could face significant delays and financial costs if we must obtain individual permit coverage from USACE for our projects.

Spills. Our operations can result in the discharge of regulated substances, including NGLs, crude oil or other products. The Clean Water Act, as amended by the federal Oil Pollution Act of 1990, as amended, ("OPA"), and comparable state laws impose restrictions and strict controls regarding the discharge of regulated substances into state waters or waters of the United States. The Clean Water Act and comparable state laws can impose substantial administrative, civil and criminal penalties for non-compliance including spills and other non-authorized discharges. The OPA subjects owners of covered facilities to strict joint and potentially unlimited liability for removal costs and other consequences of a release of oil, where the release is into navigable waters, along shorelines or in the exclusive economic zone of the United States. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require that containment dikes and similar structures be installed to help prevent the impact on navigable waters in the event of a release of oil. PHMSA, the EPA, or various state regulatory agencies, has approved our oil spill emergency response plans that are to be used in the event of a spill incident.

In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Our management believes that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our results of operations, financial position or expected cash flows.

Endangered Species. The Endangered Species Act, as amended, restricts activities that may affect endangered or threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may operate in areas that are currently designated as a habitat for endangered or threatened species or where the discovery of previously unidentified endangered species, or the designation of additional species as endangered or threatened may occur in which event such one or more developments could cause us to incur additional costs, to develop habitat conservation plans, to become subject to expansion or operating restrictions, or bans in the affected areas. Moreover, such designation of previously unprotected species as threatened or endangered in areas where our oil and natural gas exploration and production customers operate could cause our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our services.

Climate Change. Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases ("GHGs"). These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the United States, no comprehensive climate change legislation has been implemented at the federal level to date. However, Canada has implemented a federal carbon pricing regime, and, in the United States, President Biden has announced that he intends to pursue substantial reductions in greenhouse gas emissions, particularly from the oil and gas sector. For example, on January 27, 2021, President Biden signed an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, an increase in the production of offshore wind energy, and an increased emphasis on climate-related risks across government agencies and economic sectors. Additionally, the EPA has adopted rules under authority of the Clean Air Act that, among other things, establish Potential for Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating GHG emissions, such as methane, from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound ("VOC") emissions. These Subpart OOOOa standards expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. In September 2020, the EPA removed natural gas transmission and storage operations from this sector and rescinded the methane-specific requirements of the rule for production and processing facilities. However, Congress passed, and President Biden signed into law, a revocation of the 2020 rulemaking, effectively reinstating the 2016 standards. Additionally, in November 2021, the EPA issued a proposed rule that, if finalized, would establish OOOOb new source and OOOOc first-time existing source standards of performance for GHG and VOC emissions for the crude oil and natural gas well sites, natural gas gathering and boosting compressor stations, natural gas processing plants, and transmission and storage facilities. Owners or operators of affected emission units or processes would have to comply with specific standards of performance that may include leak detection using optical gas imaging and subsequent repair requirements, reduction of emissions by 95% through capture and control systems, zero-emission requirements, operations and maintenance requirements, and so-called “green well” completion requirements. The EPA plans to issue a supplemental proposal enhancing this proposed rulemaking in 2022 that will contain proposed rule text, which was not included in the November 2021 proposed rule, and anticipates issuing a final rule by the end of 2022. GHG emission standards, including methane emissions imposed on the oil and gas sector, could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. Several states have also adopted, or are considering adopting, regulations related to GHG emissions, some of which are more stringent than those implemented by the federal government.

At the international level, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France in signing the “Paris Agreement,” a treaty that requires member countries to submit individually-determined, non-binding emission reduction goals every five years beginning in 2020. Although the United States withdrew from the Paris Agreement under the Trump administration, President Biden recommitted the United States in February 2021, and, in April 2021, announced a new, more rigorous nationally determined emissions reduction level of 50-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. The international community gathered again in Glasgow in November 2021 at the 26th Conference to the Parties (“COP26”) during which multiple announcements were made, including a call for parties to eliminate fossil fuel subsidies, amongst other measures. Relatedly, the United States and European Union jointly announced at COP26 the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including “all feasible reductions” in the energy sector.

President Biden’s January 2021 climate change executive order directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands or in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices, consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs. The executive order also directed the federal government to identify “fossil fuel subsidies” to take steps to ensure that, to the extent consistent with applicable law, federal funding is not directly subsidizing fossil fuels. As noted above, a separate executive order issued in January 2021 established a Working Group that is called on to, among other things, develop methodologies for calculating the “social cost of carbon,” “social cost of nitrous oxide” and “social cost of methane.” During 2021, the Working Group published interim estimates of the social costs of carbon, methane, and nitrous oxide and sought public comment on these estimates. The Working Group’s final recommendations are expected in early 2022.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows. Litigation risks are also increasing, as several oil and gas companies have been sued for allegedly causing climate-related damages due to their production and sale of fossil fuel products or for allegedly being aware of the impacts of climate change for some time but failing to adequately disclose such risks to their investors or customers. Various investors are becoming increasingly concerned about the potential effects of climate change and may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing for fossil fuel energy companies also have become more attentive to sustainable lending practices that favor “clean” power sources such as wind and solar photovoltaic, making those sources more attractive for investment, and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero (“GFANZ”) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero by 2050. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding for fossil fuel energy companies. In late 2020, the Federal Reserve joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. More recently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Such efforts could make it more difficult to secure funding for exploration and production or midstream activities and could also increase the cost of obtaining financings and/or negatively affect terms of financings.

Finally, climatic events in the areas in which we operate, whether from climate change or otherwise, can cause disruptions and, in some cases, delays in, or suspension of, our services. These events, including but not limited to drought, winter storms, wildfire, extreme temperatures or flooding, may become more intense or more frequent as a result of climate change and could have an adverse effect on our continued operations. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities or our customers' facilities from powerful winds or rising waters, or increased costs for, or difficulty obtaining, insurance. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our NGLs and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we transport, and thus demand for our services. Despite the use of the term "global warming" as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our products could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

We recognize the need to decrease emissions and integrate alternative energy sources into our operations, and we actively pursue economically beneficial opportunities to reduce our environmental footprint throughout our operations. Protecting public health and the environment is the primary initiative of our environmental management teams, both in the construction and operation of our assets. These teams have worked to reduce our emissions and minimize our environmental impact. Some examples of our teams' efforts include:

- in our natural gas compression business, the use of our patented dual-drive technology, which offers the ability to switch compression drivers between an electric motor and a natural gas engine, allowed us to reduce our emissions of nitrogen oxide, carbon monoxide, CO2 and VOCs;
- the installation of approximately 12,000 low-emission pneumatic devices throughout our pipeline systems has allowed us to safely and efficiently adjust and control our operations and reduce methane emissions;
- the voluntary installation of thermal oxidizers, which destroy VOCs and convert methane to CO2 (a less carbon-intense GHG), thereby reducing VOC and methane emissions by 98 percent or more at many of our more than 50 natural gas processing and sweetening plants;
- the implementation of an innovative liquids management process throughout much of our natural gas gathering pipeline system has allowed us to minimize flash emissions and methane emissions;
- the use of optical gas imaging cameras at our more than 2,200 gas gathering and processing facilities as part of our leak detection and repair program allow us to reduce emissions, improve safety, reduce costs, prevent product loss, and maintain equipment integrity;
- the use of in-line inspection tools, or smart pigs, allow us to detect corrosion, cracks or other defects along our pipeline systems thereby protecting the environment and the safety of our communities, employees and landowners; and
- the use of other methods, including pipeline blowdown direct injection, liquids pipeline system optimization, crude oil truck unloading and direct injection, all of which help to reduce emissions and the release of methane into the atmosphere across our operations.

Powering our assets through renewable energy sources is an established part of our operations where it is economically viable to do so. We have reduced our carbon footprint by using a diversified mix of energy sources, including solar and wind power to generate electrical power. The percentage of electrical energy we purchase on a given day originating from solar and wind sources is approaching 20 percent. Since 2019, we have entered into dedicated solar contracts to purchase 148 megawatts of solar power to support the operations of our assets. We also operate approximately 18,000 solar panel-powered metering stations across the United States.

In February 2021, we announced the formation of our alternative energy group. This group is tasked with increasing our efforts to support renewable energy projects such as solar and/or wind farms, either as a power purchaser, or in a partnership with third party developers, when they make economic sense. This group is also focused on developing alternative energy projects aimed at reducing the environmental footprint throughout our operations, including a variety of projects related to carbon capture, utilization and sequestration of CO2.

While our environmental management initiatives have not materially impacted our capital expenditures or results of operations, we recognize that the non-financial impacts of these initiatives are of interest to our investors and other stakeholders. We voluntarily publish additional information on those initiatives; however, much of that separately published information is excluded from this annual report on Form 10-K if it is not material in the context of the consolidated Partnership and/or if it is not required by the instructions to Form 10-K. For additional information on our environmental management initiatives, including our efforts to curb GHG emissions and to integrate alternative energy sources, please see our Corporate Responsibility Report available on our website at http://www.energytransfer.com/corporate-responsibility. Information contained on our website is not part of this report.

Employee Health and Safety. We are subject to the requirements of the federal OSHA and comparable state laws that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. Historically, our costs for OSHA required activities, including general industry standards, recordkeeping 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.

Natural Resource Reviews. The National Environmental Policy Act ("NEPA") provides for an environmental impact assessment process in connection with certain projects that involve federal lands or require approvals by federal agencies. The NEPA process implicates a number of other environmental laws and regulations, including the Endangered Species Act, Migratory Bird Treaty Act, Rivers and Harbors Act, Clean Water Act, Bald and Golden Eagle Protection Act, Fish and Wildlife Coordination Act, Marine Mammal Protection Act and National Historic Preservation Act, often requiring coordination with numerous governmental authorities. The NEPA review process can be lengthy and subjective, resulting in delays in obtaining federal approvals for projects. Our projects that are subject to the NEPA can include pipeline construction and pipeline integrity projects that involve federal lands or require approvals by federal agencies. In July 2020, the Council on Environmental Quality ("CEQ") issued final revisions to NEPA regulations that seek to conform the scope of direct, indirect, and cumulative impact analyses for proposed projects subject to NEPA with existing case law. However, in October 2021, the CEQ published a proposed rule to restore, in general, NEPA regulations that were in effect before being modified by the 2020 revisions. A final rule is expected in February 2022. More stringent environmental impact analyses under or third-party challenges with respect to the sufficiency of any environmental impact statement or assessment prepared pursuant to NEPA could adversely impact such projects in the form of delays or increased compliance and mitigations costs.

Indigenous Protections. Part of our operations cross land that has historically been apportioned to various Native American/ First Nations tribes ("Indigenous Peoples"), who may exercise significant jurisdiction and sovereignty over their lands. Indigenous Peoples may also have certain treaty rights and rights to consultation on projects that may affect such lands. Our operations may be impacted to the extent these tribal governments are found to have and choose to act upon such jurisdiction over lands where we operate. For example, in 2020, the Supreme Court ruled in *McGirt v. Oklahoma* that the Muscogee (Creek) Nation reservation in Eastern Oklahoma has not been disestablished. Although the court's ruling indicates that it is limited to criminal law, as applied within the Muscogee (Creek) Nation reservation, the ruling may have significant potential implications for civil law, both in the Muscogee (Creek) Nation reservation and other reservations that may similarly be found to not have been disestablished. State courts in Oklahoma have applied the analysis in *McGirt* in ruling that the Cherokee, Chickasaw, Seminole, and Choctaw reservations likewise had not been disestablished.

On October 1, 2020, the EPA granted approval to the State of Oklahoma under Section 10211(a) of the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005 (the "SAFETE Act") to administer all of the State's existing EPA-approved regulatory programs to Indian Country within the state except: Indian allotments to which Indians titles have not been extinguished; lands that are held in trust by the United States on behalf of any Indian or Tribe; lands that are owned in fee by any Tribe where title was acquired through a treaty with the United States to which such tribe is a party and that have never been allotted to any citizen or member of such Tribe. The approval extends the State's authority for existing EPA-approved regulatory programs to all lands within the State to which the State applied such programs prior to the U.S. Supreme Court's ruling in *McGirt*. However, several Tribes expressed dissatisfaction with the consultation process performed in relation to this approval, and, in December 2021, the EPA proposed to withdraw and reconsider the October 2020 decision. Additionally, the SAFETE Act provides that any Tribe in Oklahoma may seek "Treatment as a State" by the EPA, and it is possible that one or more of the Tribes in Oklahoma may seek such an approval from EPA. At this time, we cannot predict how these jurisdictional issues may ultimately be resolved.

Human Capital Management

As of December 31, 2021, Energy Transfer and its consolidated subsidiaries employed an aggregate of 12,558 employees, 1,365 of which are represented by labor unions. We believe that our relations with our employees are good.

Our employees are our greatest asset, and we seek to attract and retain top talent by fostering a culture that is guided by our core values in a manner that respects all people and cultures, promotes safety, and focuses on the protection of public health and the environment.

Ethics and Values. We are committed to operating our business in a manner that honors and respects all people and the communities in which we do business. We recognize that people are our most valued resource, and we are committed to hiring and investing in employees who strive for excellence and live by our core values: working safely, corporate stewardship, ethics and integrity, entrepreneurial mindset, our people, excellence and results, and social responsibility. We value our employees for what they bring to our organization by embracing those from all backgrounds, cultures, and experiences. We also believe that the keys to our successes have been the cultivation of an atmosphere of inclusion and respect within our family of partnerships and sustaining organizations that promote diversity and provide support across all communities. These are the principles upon which we build and strengthen relationships among our people, our stakeholders, and those within the communities we support.

Respecting All People and All Cultures. We believe strict adherence to our Code of Business Conduct and Ethics is not only right, but is in the best interest of the Partnership, its Unitholders, its customers, and the industry in general. In all instances, the policies of the Partnership require that the business of the Partnership be conducted in a lawful and ethical manner. Every employee acting on behalf of the Partnership must adhere to these policies. Please refer to "Item 10. Directors, Executive Officers and Corporate Governance" for additional information on our Code of Business Conduct and Ethics.

Commitment to Protecting Public Health, Safety and the Environment. Protecting public health and the environment is the primary initiative for our environmental management teams, both in the construction and operation of our assets. These teams consist of environmental engineers, scientists and geologists focused on ensuring that our environmental management systems responsibly and efficiently reduce emissions, protect and preserve the land, water and air around us, and remain in compliance with all applicable regulations. Our environmental, health and safety department's more than 100 environmental and safety professionals provide environmental and safety training to our field representatives. This group also assists others throughout the organization in identifying continuous training for personnel, including the training that is required by applicable laws, regulations, standards, and permit conditions. Our safety standards and expectations are communicated to all employees and contractors with the expectation that each individual has the obligation to make safety the highest priority. Our safety culture aims to promote an open environment for discovering, resolving, and sharing safety challenges. We strive to eliminate unwanted safety events through a comprehensive process that promotes leadership, employee involvement, communication, personal responsibility to comply with standard operating procedures and regulatory requirements, effective risk reduction processes, maintaining clean facilities, contractor safety, and personal wellness. Energy Transfer's goal is operational excellence, which means an injury- and incident-free workplace. To achieve this, we strive to hire and maintain the most qualified and dedicated workforce in the industry and make safety and safety accountability part of our daily operations. The OSHA Total Reportable Incident Rate ("TRIR") is a key performance indicator by which we evaluate the success of our safety programs. TRIR provides companies with a look at their safety record performance for the year by calculating the number of recordable incidents per 200,000 hours worked. Our TRIR was 0.88 for 2021, out of more than 15 million hours worked during the year, compared to a TRIR of 0.87 for 2020. We believe the Partnership's low TRIR speaks to the investment in and focus on safety and environmental compliance as well as the reliability of our assets.

Regarding COVID-19, as an essential business providing critical energy infrastructure, the safety of our employees and the continued operation of our assets are our top priorities, and we will continue to operate in accordance with federal, state and local health guidelines and safety protocols. We have implemented several new policies and provided employees with training to help maintain the health and safety of our workforce.

For additional information on our Human Capital initiatives, please see our Corporate Responsibility Report available on our website at http://www.energytransfer.com/corporate-responsibility. Information contained on our website is not part of this report.

SEC Reporting

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the SEC. From time to time, we may also file registration and related statements pertaining to equity or debt offerings. The SEC maintains an internet website at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We provide electronic access, free of charge, to our periodic and current reports, and amendments to these reports, on our internet website located at http://www.energytransfer.com. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC. Information contained on our website is not part of this report.

ITEM 1A. RISK FACTORS

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our structure as a limited partnership, our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering an investment in our securities. Panhandle, Sunoco LP and USAC file Annual Reports on Form 10-K that include risk factors that can be reviewed for further information. The risk factors set forth below, and those included in Panhandle's, Sunoco LP's and USAC's Annual Reports, are not all the risks we face, and other factors currently considered immaterial or unknown to us may impact our future operations.

Risk Relating to the Partnership's Business

Results of Operations and Financial Condition

Our cash flow depends primarily on the cash distributions we receive from our subsidiaries, as well as our partnership interests in Sunoco LP and USAC, including the incentive distribution rights in Sunoco LP and, therefore, our cash flow is dependent upon the ability of our subsidiaries, Sunoco LP and USAC to make distributions in respect of those partnership interests.

We do not have any significant assets other than our interests in our subsidiaries. As a result, our cash flow depends on the performance of our subsidiaries, including Sunoco LP and USAC, and their ability to make cash distributions, which is dependent on the results of operations, cash flows and financial condition of our subsidiaries, including Sunoco LP and USAC.

The amount of cash that our subsidiaries distribute to us each quarter depends upon the amount of cash generated from our subsidiaries' operations, which will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas, NGLs, crude oil and refined products transported through our subsidiaries' pipelines;
- the level of throughput in processing and treating operations;
- the fees charged and the margins realized by our subsidiaries, including Sunoco LP and USAC, for their services;
- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil prices;
- the weather in their respective operating areas;
- the level of competition from other midstream, transportation and storage and retail marketing companies and other energy providers;
- the level of their respective operating costs and maintenance and integrity capital expenditures;
- the tax profile on any blocker entities treated as corporations for federal income tax purposes that are owned by any of our subsidiaries;
- prevailing economic conditions; and
- the level and results of their respective derivative activities.

In addition, the actual amount of cash that our subsidiaries, including Sunoco LP and USAC, will have available for distribution will also depend on other factors, such as:

- the level of capital expenditures they make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- debt service requirements;
- fluctuations in working capital needs;
- their ability to borrow under their respective revolving credit facilities;
- their ability to access capital markets;
- restrictions on distributions contained in their respective debt agreements; and
- the amount, if any, of cash reserves established by the board of directors and their respective general partners in their discretion for the proper conduct of their respective businesses.

Energy Transfer does not have any control over many of these factors, including the level of cash reserves established by the board of directors. Accordingly, we cannot guarantee that our subsidiaries, including Sunoco LP and USAC, will have sufficient available cash to pay a specific level of cash distributions to their respective partners.

Furthermore, Unitholders should be aware that the amount of cash that our subsidiaries have available for distribution depends primarily upon cash flow and is not solely a function of profitability, which is affected by non-cash items. As a result, our subsidiaries may declare and/or pay cash distributions during periods when they record net losses.

Income from our midstream, transportation, terminalling and storage operations is exposed to risks due to fluctuations in the demand for and price of natural gas, NGLs, crude oil and refined products that are beyond our control.

The prices for natural gas, NGLs, crude oil and refined products reflect market demand that fluctuates with changes in global and United States economic conditions and other factors, including:

- the level of domestic natural gas, NGL, refined products and oil production;
- the level of natural gas, NGL, refined products and oil imports and exports, including liquefied natural gas;
- actions taken by natural gas and oil producing nations;
- instability or other events affecting natural gas and oil producing nations;
- the impact of weather, public health crises such as pandemics (including COVID-19), and other events of nature on the demand for natural gas, NGLs, refined products and oil;
- the availability of storage, terminal and transportation systems, and refining, processing and treating facilities;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas and related products;
- the cost of capital needed to maintain or increase production levels and to construct and expand facilities;
- the impact of energy conservation and fuel efficiency efforts; and
- the extent of governmental regulations, taxation, fees and duties.

In the past, the prices of natural gas, NGLs, refined products and oil have been extremely volatile, and we expect this volatility to continue.

Any loss of business from existing customers or our inability to attract new customers due to a decline in demand for natural gas, NGLs, refined products or oil could have a material adverse effect on our revenues and results of operations. In addition, significant price fluctuations for natural gas, NGL, refined products and oil commodities could materially affect our profitability.

The outbreak of COVID-19 and recent geopolitical developments in the crude oil market could adversely impact our business, financial condition and results of operations.

On January 30, 2020, the World Health Organization (“WHO”) announced a global health emergency because of a new strain of coronavirus known as COVID-19 due to the risks it imposes on the international community as the virus spreads globally. In March 2020, the WHO classified the COVID-19 outbreak as a pandemic, based on the rapid increase in exposure globally. The global spread of COVID-19 caused a significant decline in economic activity and a reduced demand for goods and services, particularly in the energy industry, due to reduced operations and/or closures of businesses, “shelter in place” and other similar requirements imposed by government authorities, or other actions voluntarily undertaken by individuals and businesses concerned about exposure to COVID-19. The extent to which the COVID-19 pandemic continues to impact our business, operations and financial results depends on numerous evolving factors that we cannot accurately predict, including: the duration and scope of the pandemic, including the rise of new variants of the virus and their severity and global spread; governmental, business and individuals’ actions taken in response to the pandemic and the associated impact on economic activity; the effect on the level of demand for natural gas, NGLs, refined products and/or crude oil; our ability to procure materials and services from third parties that are necessary for the operation of our business; our ability to provide our services, including as a result of travel restrictions on our employees and employees of third parties that we utilize in connection with our services; the potential for key executives or employees to fall ill with COVID-19; and the ability of our customers to pay for our services if their businesses suffer as a result of the pandemic.

In addition, policy disputes between the Organization of Petroleum Exporting Countries and Russia in the first quarter of 2020 resulted in Saudi Arabia significantly discounting the price of its crude oil, as well as Saudi Arabia and Russia significantly increasing the amount of crude oil they produce. These actions led to significant volatility in crude oil prices. More specifically, the spot price for West Texas Intermediate (WTI) crude oil, for physical delivery at Cushing, Oklahoma, decreased from $63.27 per barrel on January 6, 2020 to $(36.98) per barrel on April 20, 2020 and increased to more than $60 per barrel in February 2021.

Reduced demand for natural gas, NGLs, refined products and/or crude oil caused by the COVID-19 pandemic and a decline in WTI crude oil prices caused by the actions of foreign oil-producing nations or other market factors may result in the shut-in of production from U.S. oil and gas wells, which in turn may result in decreased utilization of our midstream services related to crude oil, NGLs, refined products and natural gas. In addition, reduced demand for crude oil has resulted in an increase in worldwide crude oil storage inventories, which limits our options for end-markets for the products we transport.

The factors discussed above could have a material adverse effect on our business, results of operations and financial condition. In addition, significant price fluctuations for natural gas, NGLs, refined products and oil commodities could materially affect the value of our inventory, as well as the linefill and tank bottoms that we account for as non-current assets. We may be forced to delay some of our capital projects and our customers, who may be in financial distress, may slow down decision-making, delay planned projects or seek to renegotiate or terminate agreements with us. To the extent our counterparties are successful, we may not be able to obtain new contract terms that are favorable to us or to replace contracts that are terminated.

Further, the effects of the pandemic and geopolitical developments have market impacts, such that additional capital may be more difficult for us to obtain or available only on terms less favorable to us. Our inability to fund capital expenditures could have a material impact on our results of operations.

At this time, we cannot estimate the magnitude and duration of potential social, economic and labor instability as a direct result of COVID-19, or of potential industry disruption as a direct result of geopolitical developments in the oil market. Should any of these potential impacts continue for an extended period of time, it will have a negative impact on the demand for our services and an adverse effect on our financial position and results of operations. To the extent these factors adversely affect our business and financial results, they may also have the effect of heightening many of the other risks described in this "Risk Factors" section, as well as the risks discussed or referenced in any applicable prospectus supplement, including in the documents we incorporate by reference herein or therein, such as those relating to our indebtedness, our need to generate sufficient cash flows to service our indebtedness and our ability to comply with the covenants contained in the agreements that govern our indebtedness.

The failure to successfully combine the businesses of Energy Transfer and Enable in the expected time frame may adversely affect Energy Transfer's future results.

The success of the merger will depend, in part, on the ability of Energy Transfer to realize the anticipated benefits from combining the businesses of Energy Transfer and Enable. To realize these anticipated benefits, Energy Transfer's and Enable's businesses must be successfully combined. If the combined entity is not able to achieve these objectives, the anticipated benefits of the merger may not be realized fully or at all or may take longer to realize than expected. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the merger.

It is also possible that the process of integrating the two partnerships following the closing of the merger could result in the loss of key employees, the disruption of each partnership's ongoing businesses, or inconsistencies in their standards, controls, procedures and policies.

Any or all of these occurrences could adversely affect the combined entity's ability to maintain relationships with customers and employees or to achieve the anticipated benefits of the merger. Integration efforts between the two partnerships will also divert management attention and resources and could have an adverse effect on the combined entity.

An impairment of goodwill and intangible assets could reduce our earnings.

As of December 31, 2021, our consolidated balance sheet reflected $2.5 billion of goodwill and $5.9 billion of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' capital and balance sheet leverage as measured by debt to total capitalization.

We depend on certain key producers for our supply of natural gas and the loss of any of these key producers could adversely affect our financial results.

Certain producers who are connected to our systems represent a material source of our supply of natural gas. We are not the only option available to these producers for disposition of the natural gas they produce. To the extent that these and other producers may reduce the volumes of natural gas that they supply us, we would be adversely affected unless we were able to acquire comparable supplies of natural gas from other producers.

Our intrastate transportation and storage and interstate transportation and storage operations depend on key customers to transport natural gas through our pipelines and the pipelines of our joint ventures.

During 2021, a single customer accounted for approximately 29% of our intrastate transportation and storage revenues. During 2021, four customers collectively accounted for 38% of our interstate transportation and storage revenues.

Our joint ventures, FEP and Citrus, also depend on key customers for the transport of natural gas through their pipelines. FEP has a small number of major shippers with one shipper accounting for approximately 94% of its revenues in 2021, while Citrus has long-term agreements with its top two customers which accounted for 54% of its 2021 revenue. For the Trans-Pecos and Comanche Trail pipelines, a single customer is the primary shipper.

The failure of the major shippers on our and our joint ventures' intrastate and interstate transportation and storage pipelines to fulfill their contractual obligations could have a material adverse effect on our cash flow and results of operations if we or our joint ventures were unable to replace these customers under arrangements that provide similar economic benefits as these existing contracts.

We may be unable to retain or replace existing midstream, transportation, terminalling and storage customers or volumes due to declining demand or increased competition in crude oil, refined products, natural gas and NGL markets, which would reduce our revenues and limit our future profitability.

The retention or replacement of existing customers and the volume of services that we provide at rates sufficient to maintain or increase current revenues and cash flows depends on a number of factors beyond our control, including the price of and demand for crude oil, refined products, natural gas and NGLs in the markets we serve and competition from other service providers.

A significant portion of our sales of natural gas are to industrial customers and utilities. As a consequence of the volatility of natural gas prices and increased competition in the industry and other factors, industrial customers, utilities and other gas customers are increasingly reluctant to enter into long-term purchase contracts. Many customers purchase natural gas from more than one supplier and have the ability to change suppliers at any time. Some of these customers also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are many companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in natural gas sales markets primarily on the basis of price.

We also receive a substantial portion of our revenues by providing natural gas gathering, processing, treating, transportation and storage services. While a substantial portion of our services are sold under long-term contracts for reserved service, we also provide service on an unreserved or short-term basis. Demand for our services may be substantially reduced due to changing market prices. Declining prices may result in lower rates of natural gas production resulting in less use of services, while rising prices may diminish consumer demand and also limit the use of services. In addition, our competitors may attract our customers' business. If demand declines or competition increases, we may not be able to sustain existing levels of unreserved service or renew or extend long-term contracts as they expire or we may reduce our rates to meet competitive pressures.

Revenue from our NGL transportation systems and refined products storage is also exposed to risks due to fluctuations in demand for transportation and storage service as a result of unfavorable commodity prices, competition from nearby pipelines, and other factors. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. Reduction in demand for natural gas or NGLs due to unfavorable prices or other factors, however, may result lower rates of production under dedicated contracts and lower demand for our services. In addition, our refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers, a portion of our revenue is derived from fungible storage and throughput arrangements, under which our revenue is more dependent upon demand for storage from our customers.

The volume of crude oil and refined products transported through our crude oil and refined products pipelines and terminal facilities depends on the availability of attractively priced crude oil and refined products in the areas serviced by our assets. A period of sustained price reductions for crude oil or refined products could lead to a decline in drilling activity, production and refining of crude oil or import levels in these areas. A period of sustained increases in the price of crude oil or refined products supplied from or delivered to any of these areas could materially reduce demand for crude oil or refined products in these areas. In either case, the volumes of crude oil or refined products transported in our crude oil and refined products pipelines and terminal facilities could decline.

The loss of existing customers by our midstream, transportation, terminalling and storage facilities or a reduction in the volume of the services our customers purchase from us, or our inability to attract new customers and service volumes would negatively affect our revenues, be detrimental to our growth, and adversely affect our results of operations.

We and our subsidiaries, including Sunoco LP and USAC, are exposed to the credit risk of our customers and derivative counterparties, and an increase in the nonpayment and nonperformance by our customers or derivative counterparties could reduce our ability to make distributions to our Unitholders.

We, Sunoco LP and USAC are subject to risks of loss resulting from nonpayment or nonperformance by our, Sunoco LP's and USAC's customers. Commodity price volatility and/or the tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment and nonperformance by our customers. In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any material nonpayment or nonperformance by our customers or our derivative counterparties could reduce our ability to make distributions to our Unitholders. Any substantial increase in the nonpayment and nonperformance by our customers could have a material effect on our, Sunoco LP's and USAC's results of operations and operating cash flows.

Due to market disruptions involving the ongoing COVID-19 pandemic, some of our counterparties may be forced to file for bankruptcy protection, in which case our existing contracts with those counterparties may be rejected by the bankruptcy court. Following the request of one of our FERC-regulated natural pipelines, the FERC commenced an investigation into whether the public interest requires abrogation or modification of a firm transportation agreement and an interruptible transportation agreement with one of our shippers. By order dated November 9, 2020, FERC held that the record did not support a finding that the public interest presently requires abrogation or modification of the subject firm transportation agreement. However, actual determination regarding the contract will depend upon further action by the counterparty and any further bankruptcy-related proceedings. If a counterparty is successful in rejecting an existing contract in bankruptcy, we expect that we would attempt to negotiate replacement contracts with those counterparties and, depending on the availability of alternatives to our services, these contracts may have terms that are less favorable to us than the contracts rejected in bankruptcy court.

The profitability of certain activities in our natural gas gathering, processing, transportation and storage operations are largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs.

For a portion of the natural gas gathered on our systems, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices.

We also enter into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers.

Under percent-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements, our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our revenues and results of operations.

Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our gross margins generally decrease when the price of natural gas increases relative to the price of NGLs.

When we process the gas for a fee under processing fee agreements, we may guarantee recoveries to the producer. If recoveries are less than those guaranteed to the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole.

We also receive fees and retain gas in kind from our natural gas transportation and storage customers. Our fuel retention fees and the value of gas that we retain in kind are directly affected by changes in natural gas prices. Decreases in natural gas prices tend to decrease our fuel retention fees and the value of retained gas.

In addition, we receive revenue from our off-gas processing and fractionating system in south Louisiana primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

For our midstream segment, we generally analyze gross margin based on fee-based margin (which includes revenues from processing fee arrangements) and non-fee-based margin (which includes gross margin earned on percent-of-proceeds and keep-whole arrangements). The amount of segment margin earned by our midstream segment from fee-based and non-fee-based arrangements (individually and as a percentage of total revenues) will be impacted by the volumes associated with both types of arrangements, as well as commodity prices; therefore, the dollar amounts and the relative magnitude of gross margin from fee-based and non-fee-based arrangements in future periods may be significantly different from results reported in previous periods.

Our midstream facilities and transportation pipelines provide services related to natural gas wells that experience production declines over time, which we may not be able to replace with natural gas production from newly drilled wells in the same natural gas basins or in other new natural gas producing areas.

In order to maintain or increase throughput levels on our gathering systems and transportation pipeline systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies and natural gas transportation services.

A substantial portion of our assets, including our gathering systems and our processing and treating plants, are connected to natural gas reserves and wells that experience declining production over time. Our gas transportation pipelines are also dependent upon natural gas production in areas served by our gathering systems or in areas served by other gathering systems or transportation pipelines that connect with our transportation pipelines. We may not be able to obtain additional contracts for natural gas supplies for our natural gas gathering systems, and we may be unable to maintain or increase the levels of natural gas throughput on our transportation pipelines. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity and production of natural gas near our gathering systems or in areas that provide access to our transportation pipelines or markets to which our systems connect. We have no control over the level of drilling activity in our areas of operation, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, we have no control over producers or their production and contracting decisions.

While a substantial portion of our services are provided under long-term contracts for reserved service, we also provide service on an unreserved basis. The reserves available through the supply basins connected to our gathering, processing, treating, transportation and storage facilities may decline and may not be replaced by other sources of supply. A decrease in development or production activity could cause a decrease in the volume of unreserved services we provide and a decrease in the number and volume of our contracts for reserved transportation service over the long run, which in each case would adversely affect our revenues and results of operations.

If we are unable to replace any significant volume declines with additional volumes from other sources, our results of operations and cash flows could be materially and adversely affected.

Our revenues depend on our customers' ability to use our pipelines and third-party pipelines over which we have no control.

Our natural gas transportation, storage and NGL businesses depend, in part, on our customers' ability to obtain access to pipelines to deliver gas to us and receive gas from us. Many of these pipelines are owned by parties not affiliated with us. Any interruption of service on our pipelines or third-party pipelines due to testing, line repair, reduced operating pressures, or other causes or adverse change in terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport natural gas to and from our pipelines and facilities and a corresponding material adverse effect on our transportation and storage revenues. In addition, the rates charged by interconnected pipelines for transportation to and from our facilities affect the utilization and value of our storage services. Significant changes in the rates charged by those pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues.

Shippers using our oil pipelines and terminals are also dependent upon our pipelines and connections to third-party pipelines to receive and deliver crude oil and products. Any interruptions or reduction in the capabilities of these pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes transported in our pipelines or through our terminals. Similarly, if additional shippers begin transporting volume over interconnecting oil pipelines, the allocations of pipeline capacity to our existing shippers on these interconnecting pipelines could be reduced, which also could reduce volumes transported in its pipelines or through our terminals. Allocation reductions of this nature are not infrequent and are beyond our control. Any such interruptions or allocation reductions that, individually or in the aggregate, are material or continue for a sustained period of time could have a material adverse effect on our results of operations, financial position, or cash flows.

The inability to continue to access lands owned by third parties could adversely affect our ability to operate and our financial results.

Our ability to operate our pipeline systems on certain lands owned by third parties will depend on our success in maintaining existing rights-of-way and obtaining new rights-of-way on those lands. We are parties to rights-of-way agreements, permits and licenses authorizing land use with numerous parties, including, private land owners, governmental entities, Native American tribes, rail carriers, public utilities and others. For more information, see our regulatory disclosure titled “Indigenous Protections.” Our ability to secure extensions of existing agreements, permits and licenses is essential to our continuing business operations, and securing additional rights-of-way will be critical to our ability to pursue expansion projects. We cannot provide any assurance that we will be able to maintain access to existing rights-of-way upon the expiration of the current grants, that all of the rights-of-way will be obtained in a timely fashion or that we will acquire new rights-of-way as needed.

Further, whether we have the power of eminent domain for our pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state and the ownership of the land to which we seek access. When we exercise eminent down rights or negotiate private agreements cases, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located. For example, following a decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. Any loss of rights with respect to our real property, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to Unitholders.

Our storage operations are influenced by the overall forward market for crude oil and other products we store, and certain market conditions may adversely affect our financial and operating results.

Our storage operations are influenced by the overall forward market for crude oil and other products we store. A contango market (meaning that the price of crude oil or other products for future delivery is higher than the current price) is associated with greater demand for storage capacity, because a party can simultaneously purchase crude oil or other products at current prices for storage and sell at higher prices for future delivery. A backwardated market (meaning that the price of crude oil or other products for future delivery is lower than the current price) is associated with lower demand for storage capacity because a party can capture a premium for prompt delivery of crude oil or other products rather than storing it for future sale. A prolonged backwardated market, or other adverse market conditions, could have an adverse impact on its ability to negotiate favorable prices under new or renewing storage contracts, which could have an adverse impact on our storage revenues. As a result, the overall forward market for crude oil or other products may have an adverse effect on our financial condition or results of operations.

Competition for water resources or limitations on water usage for hydraulic fracturing could disrupt crude oil and natural gas production from shale formations.

Hydraulic fracturing is the process of creating or expanding cracks by pumping water, sand and chemicals under high pressure into an underground formation in order to increase the productivity of crude oil and natural gas wells. Water used in the process is generally fresh water, recycled produced water or salt water. There is competition for fresh water from municipalities, farmers, ranchers and industrial users. In addition, the available supply of fresh water can also be reduced directly by drought. Prolonged drought conditions increase the intensity of competition for fresh water. Limitations on oil and gas producers’ access to fresh water may restrict their ability to use hydraulic fracturing and could reduce new production. Such disruptions could potentially have a material adverse impact on our financial condition or results of operations.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas pipeline and other facilities operate at high pressures. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

If one or more facilities that are owned by us, or that deliver natural gas or other products to us, are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to Unitholders.

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

The United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Some of our facilities are subject to standards and procedures required by the Chemical Facility Anti-Terrorism Standards. We believe we are in compliance with all material requirements; however, such compliance may not prevent a terrorist attack from causing material damage to our facilities or pipelines. Any such terrorist attack on our facilities or pipelines, those of our customers, or in some cases, those of other pipelines could have a material adverse effect on our business, financial condition and results of operations.

Our business could be affected adversely by union disputes and strikes or work stoppages by unionized employees.

As of December 31, 2021, approximately 11% of our workforce is covered by a number of collective bargaining agreements with various terms and dates of expiration. There can be no assurances that we will not experience a work stoppage in the future as a result of labor disagreements. Any work stoppage could, depending on the affected operations and the length of the work stoppage, have a material adverse effect on our business, financial position, results of operations or cash flows.

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

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

Our information technology and infrastructure, physical assets and data, may be vulnerable to unauthorized access, computer viruses, malicious attacks and other events (e.g., distributed denial of service attacks, ransomware attacks) that are beyond our control. These events can result from malfeasance by external parties, such as hackers, or due to human error by our or our service providers' employees and contractors (e.g., due to social engineering or phishing attacks). In addition, the COVID-19 pandemic continues to present additional operational and cybersecurity risks to our information technology infrastructure and physical assets due to our providers' work-from-home arrangements.

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

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

Our operations could be disrupted if our information systems fail, causing increased expenses and loss of sales.

Our business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including our enterprise resource planning tools. We process a large number of transactions on a daily basis and rely upon the proper functioning of computer systems. If a key system was to fail or experience unscheduled downtime for any reason, even if only for a short period, our operations and financial results could be affected adversely. Our systems could be damaged or interrupted by a security breach, fire, flood, power loss, telecommunications failure or similar event. We have a formal disaster recovery plan in place, but this plan may not entirely prevent delays or other complications that could arise from an information systems failure. Our business interruption insurance may not compensate us adequately for losses that may occur.

Product liability claims and litigation could adversely affect our business and results of operations.

Product liability is a significant commercial risk. Substantial damage awards have been made in certain jurisdictions against manufacturers and resellers based upon claims for injuries caused by the use of or exposure to various products. There can be no assurance that product liability claims against us would not have a material adverse effect on our business or results of operations.

Along with other refiners, manufacturers and sellers of gasoline, ETC Sunoco is a defendant in numerous lawsuits that allege MTBE contamination in groundwater. Plaintiffs, who include water purveyors and municipalities responsible for supplying drinking water and private well owners, are seeking compensatory damages (and in some cases injunctive relief, punitive damages and attorneys' fees) for claims relating to the alleged manufacture and distribution of a defective product (MTBE-containing gasoline) that contaminates groundwater, and general allegations of product liability, nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. There has been insufficient information developed about the plaintiffs' legal theories or the facts that would be relevant to an analysis of the ultimate liability to ETC Sunoco. An adverse determination of liability related to these allegations or other product liability claims against ETC Sunoco could have a material adverse effect on our business or results of operations.

We do not control, and therefore may not be able to cause or prevent certain actions by, certain of our joint ventures.

Certain of our operations are conducted through joint ventures, some of which have their own governing boards. With respect to our joint ventures, we share ownership and management responsibilities with partners that may not share our goals and objectives. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in their or the joint venture's best interests. Likewise, we may be unable to prevent actions of the joint venture. Differences in views among joint venture partners may result in delayed decisions or failures to agree on major matters, such as large expenditures or contractual commitments, the construction or acquisition of assets or borrowing money, among others. Delay or failure to agree may prevent action with respect to such matters, even though such action may serve our best interest or that of the joint venture. Accordingly, delayed decisions and disagreements could adversely affect the business and operations of the joint ventures and, in turn, our business and operations.

The use of derivative financial instruments could result in material financial losses by us.

From time to time, we and/or our subsidiaries have sought to reduce our exposure to fluctuations in commodity prices and interest rates by using derivative financial instruments and other risk management mechanisms and by our trading, marketing and/or system optimization activities. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions that are effective economically (whether to mitigate our exposure to fluctuations in commodity prices, or to balance our exposure to fixed and variable interest rates), these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at that point. It is also not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. Our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

In addition, our derivatives activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the derivative arrangement, the hedge is imperfect, commodity prices move unfavorably related to our physical or financial positions or hedging policies and procedures are not followed.

Increasing levels of congestion in the Houston Ship Channel could result in a diversion of business to less busy ports.

Our Gulf Coast facilities are strategically situated on prime real estate located in the Houston Ship Channel, which is in close proximity to both supply sources and demand sources. In recent years, the success of the Port of Houston has led to an increase in vessel traffic driven in part by the growing overseas demand for U.S. crude, gasoline, liquefied natural gas and petrochemicals and in part by the Port of Houston’s recent decision to accept large container vessels, which can restrict the flow of other cargo. Increasing congestion in the Port of Houston could cause our customers or potential customers to divert their business to smaller ports in the Gulf of Mexico, which could result in lower utilization of our facilities.

The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results.

Certain of our subsidiaries provide pension plan and other postretirement healthcare benefits to certain of their employees. The costs of providing pension and other postretirement health care benefits and related funding requirements are subject to changes in pension and other postretirement fund values, changing demographics and fluctuating actuarial assumptions that may have a material adverse effect on the Partnership’s future consolidated financial results. While certain of the costs incurred in providing such pension and other postretirement healthcare benefits are recovered through the rates charged by the Partnership’s regulated businesses, the

Partnership’s subsidiaries may not recover all of the costs and those rates are generally not immediately responsive to current market conditions or funding requirements. Additionally, if the current cost recovery mechanisms are changed or eliminated, the impact of these benefits on operating results could significantly increase.

Mergers among customers and competitors could result in lower volumes being shipped on our pipelines or products stored in or distributed through our terminals, or reduced crude oil marketing margins or volumes.

Mergers between existing customers could provide strong economic incentives for the combined entities to utilize their existing systems instead of our systems in those markets where the systems compete. As a result, we could lose some or all of the volumes and associated revenues from these customers and could experience difficulty in replacing those lost volumes and revenues, which could materially and adversely affect our results of operations, financial position, or cash flows.

Fraudulent activity or misuse of proprietary data involving our outsourcing partners could expose us to additional liability.

We utilize both affiliated entities and third parties in the processing of our information and data. Breaches of security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information, or sensitive or confidential data about us or our customers, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose us to a risk of loss, or misuse of this information, result in litigation and potential liability, lead to reputational damage, increase our compliance costs, or otherwise harm our business.

Changes in currency exchange rates could adversely affect our results of operations for our Canadian operations.

A portion of our revenue is generated from operations in Canada, which use the Canadian dollar as the functional currency. Therefore, changes in the exchange rate between the U.S. dollar and the Canadian dollar could adversely affect our results of operations.

We are subject to the risks of doing business outside of the U.S.

The success of our business depends, in part, on continued performance in our non-U.S. operations. We currently have operations in Canada. In addition to the other risks described in this report on Form 10-K, there are numerous risks and uncertainties that specifically affect our non-U.S. operations. These risks and uncertainties include political and economic instability, changes in local governmental laws, regulations and policies, including those related to tariffs, investments, taxation, exchange controls, employment regulations and repatriation of earnings, and enforcement of contract and intellectual property rights. International transactions may also involve increased financial and legal risks due to differing legal systems and customs, including risks of non-compliance with U.S. and local laws affecting our activities abroad, including compliance with the U.S. Foreign Corrupt Practices Act. While these factors and the impact of these factors are difficult to predict, any one or more of them could adversely affect our financial and operational results.

Our trucking fleet operations are subject to the Federal Motor Carrier Safety Regulations which are enacted, reviewed and amended by the Federal Motor Carrier Safety Administration ("FMCSA"). Our fleet currently has a "satisfactory" safety rating; however, if our safety rating were downgraded to "unsatisfactory," our business and results of operations could be adversely affected.

All federally regulated carriers' safety ratings are measured through a program implemented by the FMCSA known as the Compliance Safety Accountability ("CSA") program. The CSA program measures a carrier's safety performance based on violations observed during roadside inspections as opposed to compliance audits performed by the FMCSA. The quantity and severity of any violations are compared to a peer group of companies of comparable size and annual mileage. If a company rises above a threshold established by the FMCSA, it is subject to action from the FMCSA. There is a progressive intervention strategy that begins with a company providing the FMCSA with an acceptable plan of corrective action that the company will implement. If the issues are not corrected, the intervention escalates to on-site compliance audits and ultimately an "unsatisfactory" rating and the revocation of its operating authority by the FMCSA could have an adverse effect on our business, results of operations and financial condition.

Indebtedness

Our debt level and debt agreements may limit our ability to make distributions to Unitholders and may limit our future financial and operating flexibility.

As of December 31, 2021, we had approximately $49.70 billion of consolidated debt, excluding the debt of our unconsolidated joint ventures. Our level of indebtedness affects our operations in several ways, including, among other things:

- a significant portion of our and our subsidiaries' cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions;
- covenants contained in our and our subsidiaries' existing debt agreements require us and them, as applicable, to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our and our subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership, corporate or limited liability company purposes, as applicable, may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt;
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level; and
- failure by us or our subsidiaries to comply with the various restrictive covenants of our respective debt agreements could negatively impact our ability to incur additional debt, including our ability to utilize the available capacity under our revolving credit facility, and our ability to pay our distributions.

The debt level and debt agreements of our subsidiaries, including Sunoco LP and USAC, may limit the distributions we receive from these subsidiaries, as well as our future financial and operating flexibility.

Our subsidiaries' levels of indebtedness affect their operations in several ways, including, among other things:

- a significant portion of our subsidiaries' cash flows from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes, including payment of distributions to us;
- covenants contained in our subsidiaries' existing debt agreements require the respective subsidiaries, as applicable, to meet financial tests that may adversely affect their flexibility in planning for and reacting to changes in their respective businesses;

- our subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership, corporate or limited liability company purposes, as applicable, may be limited;
- our subsidiaries may be at a competitive disadvantage relative to similar companies that have less debt;
- our subsidiaries may be more vulnerable to adverse economic and industry conditions as a result of their debt levels;
- failure by our subsidiaries to comply with the various restrictive covenants of the respective debt agreements could negatively impact the respective subsidiaries' ability to incur additional debt, including their ability to utilize the available capacity under their revolving credit facilities, and to pay distributions to us and their unitholders.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service our debt or to repay debt at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our Available Cash (as defined in our partnership agreement) to our Unitholders of record and our general partner. Available Cash is generally all of our cash on hand as of the end of a quarter, adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating subsidiaries in amounts it determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating subsidiaries (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our Unitholders and our general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to changes in interest rates. Approximately $5.26 billion of our consolidated debt as of December 31, 2021 bears interest at variable interest rates and the remainder bears interest at fixed rates. To the extent that we have debt with floating interest rates, our results of operations, cash flows and financial condition could be materially adversely affected by increases in interest rates. We manage a portion of our interest rate exposures by utilizing interest rate swaps.

An increase in interest rates could impact demand for our storage capacity.

There is a financing cost for a storage capacity user to own crude oil while it is stored. That financing cost is impacted by the cost of capital or interest rate incurred by the storage user, in addition to the commodity cost of the crude oil in inventory. Absent other factors, a higher financing cost adversely impacts the economics of storing crude oil for future sale. As a result, a significant increase in interest rates could adversely affect the demand for our storage capacity independent of other market factors.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our Common Units. Any such reduction in demand for our Common Units resulting from other more attractive investment opportunities may cause the trading price of our Common Units to decline.

A downgrade of our credit ratings could impact our and our subsidiaries' liquidity, access to capital and costs of doing business, and maintaining credit ratings is under the control of independent third parties.

A downgrade of our credit ratings may increase our and our subsidiaries' cost of borrowing and could require us to post collateral with third parties, negatively impacting our available liquidity. Our and our subsidiaries' ability to access capital markets could also be limited by a downgrade of our credit ratings and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions;
- declining market prices for crude oil, natural gas, NGLs and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies; and
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

Capital Projects and Future Growth

If we and our subsidiaries do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our results of operations and our ability to grow and to make distributions to Unitholders will depend in part on our ability to make acquisitions that are accretive to our distributable cash flow per unit.

We may be unable to make accretive acquisitions for any of the following reasons, among others:

- because we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- because we are unable to raise financing for such acquisitions on economically acceptable terms; or
- because we are outbid by competitors, some of which are substantially larger than us and have greater financial resources and lower costs of capital then we do.

Furthermore, even if we consummate acquisitions that we believe will be accretive, those acquisitions may in fact adversely affect our results of operations or result in a decrease in distributable cash flow per unit. Any acquisition involves potential risks, including the risk that we may:

- fail to realize anticipated benefits, such as new customer relationships, cost-savings or cash flow enhancements;
- decrease our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- significantly increase our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- encounter difficulties operating in new geographic areas or new lines of business;
- incur or assume unanticipated liabilities, losses or costs associated with the business or assets acquired for which we are not indemnified or for which the indemnity is inadequate;
- be unable to hire, train or retrain qualified personnel to manage and operate our growing business and assets;
- less effectively manage our historical assets, due to the diversion of management’s attention from other business concerns; or
- incur other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges.

If we consummate future acquisitions, our capitalization and results of operations may change significantly. As we determine the application of our funds and other resources, Unitholders will not have an opportunity to evaluate the economic, financial and other relevant information that we will consider.

Capital projects will require significant amounts of debt and equity financing, which may not be available to us on acceptable terms, or at all.

We plan to fund our growth capital expenditures, including any new pipeline construction projects and improvements or repairs to existing facilities that we may undertake, with proceeds from sales of our debt and equity securities and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms satisfactory to us, or at all. If we are unable to finance our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

A significant increase in our indebtedness that is proportionately greater than our issuance of equity could negatively impact our and our subsidiaries’ credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement, which could have a material adverse effect on our financial condition, results of operations and cash flows.

If we do not continue to construct new pipelines, our future growth could be limited.

Our results of operations and ability to grow and to increase distributable cash flow per unit will depend, in part, on our ability to construct pipelines that are accretive to our distributable cash flow. We may be unable to construct pipelines that are accretive to distributable cash flow for any of the following reasons, among others:

- we are unable to identify pipeline construction opportunities with favorable projected financial returns;
- we are unable to obtain necessary governmental approvals and contracts with qualified contractors and vendors on acceptable terms;
- we are unable to raise financing for our identified pipeline construction opportunities; or
- we are unable to secure sufficient transportation commitments from potential customers due to competition from other pipeline construction projects or for other reasons.

Furthermore, even if we construct a pipeline that we believe will be accretive, the pipeline may in fact adversely affect our results of operations or results from those projected prior to commencement of construction and other factors.

Expanding our business by constructing new pipelines and related facilities subjects us to risks.

One of the ways that we have grown our business is through the construction of additions to our existing gathering, compression, treating, processing and transportation systems. The construction of new pipelines and related facilities (or the improvement and repair of existing facilities) involves numerous regulatory, environmental, political and legal uncertainties beyond our control and requires the expenditure of significant amounts of capital that we will be required to finance through borrowings, the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule, at all, or at the budgeted cost. A variety of factors outside our control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third-party contractors, may result in increased costs or delays in construction. For example, in recent years, pipeline projects by many companies have been subject to several challenges by environmental groups, such as challenges to agency reviews under the NEPA and to the USACE NWP program. For more information on the NWP program, see our regulatory disclosure titled “Clean Water Act”. Separately, cost overruns or delays in completing a project could have a material adverse effect on our results of operations and cash flows. Moreover, our revenues may not increase immediately following the completion of a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, but we may not materially increase our revenues until long after the project’s completion. In addition, the success of a pipeline construction project will likely depend upon the level of oil and natural gas exploration and development drilling activity and the demand for pipeline transportation in the areas proposed to be serviced by the project as well as our ability to obtain commitments from producers in the area to utilize the newly constructed pipelines. In this regard, we may construct facilities to capture anticipated future growth in oil or natural gas production in a region in which such growth does not materialize. As a result, new facilities may be unable to attract enough throughput or contracted capacity reservation commitments to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

The liquefaction project is dependent upon securing long-term contractual arrangements for the off-take of LNG on terms sufficient to support the financial viability of the project.

LCL, our wholly-owned subsidiary, is in the process of developing a liquefaction project at the site of our existing regasification facility in Lake Charles, Louisiana. The project would utilize existing dock and storage facilities owned by us located on the Lake Charles site. The parties’ determination as to the feasibility of the project will be particularly dependent upon the prospects for securing long-term contractual arrangements for the off-take of LNG which in turn will be dependent upon supply and demand factors affecting the price of LNG in foreign markets. The financial viability of the project will also be dependent upon a number of other factors, including the expected cost to construct the liquefaction facility, the terms and conditions of the financing for the construction of the liquefaction facility, the cost of the natural gas supply, the costs to transport natural gas to the liquefaction facility, the costs to operate the liquefaction facility and the costs to transport LNG from the liquefaction facility to customers in foreign markets (particularly Europe and Asia). Some of these costs fluctuate based on a variety of factors, including supply and demand factors affecting the price of natural gas in the United States, supply and demand factors affecting the costs for construction services for large infrastructure projects in the United States, and general economic conditions, there can be no assurance that the parties will determine to proceed to develop this project.

The construction of the liquefaction project remains subject to further approvals and some approvals may be subject to further conditions, review and/or revocation.

While LCL has received authorization from the DOE to export LNG to non-Free Trade Agreements (“non-FTA”) countries, the non-FTA authorization is subject to review, and the DOE may impose additional approval and permit requirements in the future or revoke the non-FTA authorization should the DOE conclude that such export authorization is inconsistent with the public interest. The FERC order (issued December 17, 2015) authorizing LCL to site, construct and operate the liquefaction project contains a condition requiring all phases of the liquefaction project to be completed and in-service within five years of the date of the order. The order also requires the modifications to our Trunkline pipeline facilities that connect to our Lake Charles facility and additionally requires execution of a transportation contract for natural gas supply to the liquefaction facility prior to the initiation of construction of the liquefaction facility. On December 5, 2019, the FERC granted an extension of time until and including December 16, 2025, to complete construction of the liquefaction project and pipeline facilities modifications and place the facilities into service. On January 31, 2022, LCL filed seeking an extension of time until and including December 16, 2028 to complete construction of the liquefaction facilities modifications and place the facilities into service.

Integration of assets acquired in past acquisitions or future acquisitions with our existing business will be a complex and time-consuming process. A failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, financial condition, results of operations or cash available for distribution to Unitholders.

The difficulties of integrating past and future acquisitions with our business include, among other things:

- operating a larger combined organization in new geographic areas and new lines of business;
- hiring, training or retaining qualified personnel to manage and operate our growing business and assets;
- integrating management teams and employees into existing operations and establishing effective communication and information exchange with such management teams and employees;
- diversion of management's attention from our existing business;
- assimilation of acquired assets and operations, including additional regulatory programs;
- loss of customers or key employees;
- maintaining an effective system of internal controls in compliance with the Sarbanes-Oxley Act of 2002 as well as other regulatory compliance and corporate governance matters; and
- integrating new technology systems for financial reporting.

If any of these risks or other unanticipated liabilities or costs were to materialize, then desired benefits from past acquisitions and future acquisitions resulting in a negative impact to our future results of operations. In addition, acquired assets may perform at levels below the forecasts used to evaluate their acquisition, due to factors beyond our control. If the acquired assets perform at levels below the forecasts, then our future results of operations could be negatively impacted.

Also, our reviews of proposed business or asset acquisitions are inherently imperfect because it is generally not feasible to perform an in-depth review of each such proposal given time constraints imposed by sellers. Even if performed, a detailed review of assets and businesses may not reveal existing or potential problems and may not provide sufficient familiarity with such business or assets to fully assess their deficiencies and potential. Inspections may not be performed on every asset, and environmental problems, may not be observable even when an inspection is undertaken.

We are affected by competition from other midstream, transportation, terminalling and storage companies.

We experience competition in all of our business segments. With respect to our midstream operations, we compete for both natural gas supplies and customers for our services. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas.

Our natural gas and NGL transportation pipelines and storage facilities compete with other interstate and intrastate pipeline companies and storage providers in the transportation and storage of natural gas and NGLs. The principal elements of competition among pipelines are rates, terms of service, access to sources of supply and the flexibility and reliability of service. Natural gas and NGLs also compete with other forms of energy, including electricity, coal, fuel oils and renewable or alternative energy. Competition among fuels and energy supplies is primarily based on price; however, non-price factors, including governmental regulation, environmental impacts, efficiency, ease of use and handling, and the availability of subsidies and tax benefits also affects competitive outcomes.

In markets served by our NGL pipelines, we compete with other pipeline companies and barge, rail and truck fleet operations. We also face competition with other storage and fractionation facilities based on fees charged and the ability to receive, distribute and/or fractionate the customer's products.

Our crude oil and refined petroleum products pipelines face significant competition from other pipelines for large volume shipments. These operations also face competition from trucks for incremental and marginal volumes in the areas we serve. Further, our crude and refined product terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

We, Sunoco LP and USAC may not be able to fully execute our growth strategy if we encounter increased competition for qualified assets.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream, transportation, storage and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding the acquisition of additional assets and businesses, stand-alone development projects or other transactions that we believe will present opportunities to realize synergies and increase our cash flow.

Consistent with our strategy, we may, from time to time, engage in discussions with potential sellers regarding the possible acquisition of additional assets or businesses. Such acquisition efforts may involve our participation in processes that involve a number of potential buyers, commonly referred to as “auction” processes, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We cannot give assurance that our acquisition efforts will be successful or that any acquisition will be completed on terms considered favorable to us.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in us losing to other bidders more often or acquiring assets at higher prices, both of which would limit our ability to fully execute our growth strategy. Inability to execute our growth strategy may materially adversely impact our results of operations.

We compete with other businesses in our market with respect to attracting and retaining qualified employees.

Our continued success depends on our ability to attract and retain qualified personnel in all areas of our business. We compete with other businesses in our market with respect to attracting and retaining qualified employees. A tight labor market, increased overtime and a higher full-time employee ratio may cause labor costs to increase. A shortage of qualified employees may require us to enhance wage and benefits packages in order to compete effectively in the hiring and retention of such employees or to hire more expensive temporary employees. No assurance can be given that our labor costs will not increase, or that such increases can be recovered through increased prices charged to customers. We are especially vulnerable to labor shortages in oil and gas drilling areas when energy prices drive higher exploration and production activity.

Regulatory Matters

Litigation commenced by The Williams Companies, Inc (“Williams”) against Energy Transfer and its affiliates could require Energy Transfer to make a substantial payment to Williams.

Williams filed a complaint against Energy Transfer and its affiliates (“Energy Transfer Defendants”) in the Delaware Court of Chancery (the “Court”), alleging that the Energy Transfer Defendants breached the merger agreement (the “Merger Agreement”) between Williams, Energy Transfer, and several of Energy Transfer’s affiliates by (i) failing to use commercially reasonable efforts to obtain the delivery of a tax opinion concerning Section 721 of the Internal Revenue Code, (ii) issuing the Partnership’s series A convertible preferred units (the “Issuance”), and (c) making allegedly untrue representations and warranties in the Merger Agreement (collectively, the “Williams Litigation”). Following a ruling by the Court on June 24, 2016, which allowed for the subsequent termination of the Merger Agreement by Energy Transfer on June 29, 2016, Williams filed a notice of appeal to the Supreme Court of Delaware. Williams filed an amended complaint on September 16, 2016 and sought a $410 million termination fee (the ‘Termination Fee”) and additional damages of up to $10 billion based on the purported lost value of the merger consideration. These damages claims are based on the alleged breaches of the Merger Agreement, as well as new allegations that the Energy Transfer Defendants breached an additional representation and warranty in the Merger Agreement. The Energy Transfer Defendants filed amended counterclaims and affirmative defenses on September 23, 2016 and sought a $1.48 billion termination fee under the Merger Agreement and additional damages caused by Williams’ misconduct. These damages claims are based on the alleged breaches of the Merger Agreement, as well as new allegations that Williams breached the Merger Agreement by failing to disclose material information that was required to be disclosed in the Form S-4. On September 29, 2016, Williams filed a motion to dismiss the Energy Transfer Defendant’ amended counterclaims and to strike certain of the Energy Transfer Defendants’ affirmative defenses. On December 1, 2017, the Court issued a Memorandum Opinion granting Williams’ motion to dismiss in part and denying it in part. On March 23, 2017, the Delaware Supreme Court affirmed the Court's June 24, 2016 ruling, and as a result, Williams conceded that its $10 billion damages claim is foreclosed, although the Termination Fee claim remained pending.

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. The Court did not reach Williams' tax-related claims. 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.

Energy Transfer Defendants cannot predict the ultimate outcome of the Williams Litigation nor can Energy Transfer Defendants predict the amount of time and expense that will be required to resolve the Williams Litigation. Energy Transfer Defendants believe that Williams' claims are without merit and that Williams materially breached the Merger Agreement.

Increased regulation of hydraulic fracturing or produced water disposal could result in reductions or delays in crude oil and natural gas production in our areas of operation, which could adversely impact our business and results of operations.

The hydraulic fracturing process has come under considerable scrutiny from sections of the public as well as environmental and other groups asserting that chemicals used in the hydraulic fracturing process could adversely affect drinking water supplies and may have other detrimental impacts on public health, safety, welfare and the environment. In addition, the water disposal process has come under scrutiny from sections of the public as well as environmental and other groups asserting that the operation of certain water disposal wells has caused increased seismic activity. Additionally, several candidates for political office in both state and federal government have announced intentions to impose greater restrictions on hydraulic fracturing or produced water disposal. For example, on January 27, 2021, the Biden Administration issued an executive order temporarily suspending the issuance of new authorizations, and suspending the issuance of new leases pending completion of a review of current practices, for oil and gas development on federal lands and waters (but not tribal lands that the federal government merely holds in trust). The suspension of these federal leasing activities prompted legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district judge in Louisiana in June 2021, effectively halting implementation of the leasing suspension. Relatedly, the Department of the Interior ("DOI") released its report on federal gas leasing and permitting practices in November 2021, referencing a number of recommendations and an overarching intent to modernize the federal oil and gas leasing program, including by adjusting royalty and bonding rates, prioritizing leasing in areas with known resource potential, and avoiding leasing that conflicts with recreation, wildlife habitat, conservation, and historical and cultural resources. Implementation of many of the recommendations in the DOI report will require Congressional action and we cannot predict the extent to which the recommendations may be implemented now or in the future, but restrictions on federal oil and gas activities have the potential to result in increased costs on us and our customers, decrease demand for our services on federal lands, and adversely impact our business. Separately, the Colorado Oil and Gas Conservation Commission adopted new rules to cover a variety of matters related to public health, safety, welfare, wildlife, and environmental resources; most significantly, these rule changes establish more stringent setbacks (2,000-foot, instead of the prior 500-foot) on new oil and gas development and eliminate routine flaring and venting of natural gas at new or existing wells across the state, each subject to only limited exceptions. Some local communities have adopted, or are considering adopting, additional restrictions for oil and gas activities, such as requiring even greater setbacks. While the final impacts of these developments cannot be predicted, the adoption of new laws or regulations imposing additional permitting, disclosures, restrictions or costs related to hydraulic fracturing or produced water disposal or prohibiting hydraulic fracturing in proximity to areas considered to be environmentally sensitive could make drilling certain wells impossible or less economically attractive. As a result, the volume of crude oil and natural gas we gather, transport and store for our customers could be substantially reduced which could have an adverse effect on our financial condition or results of operations.

Legal or regulatory actions related to the Dakota Access pipeline could cause an interruption to current or future operations, which could have an adverse effect on our business and results of operations.

On July 27, 2016, the Standing Rock Sioux Tribe and other Native American tribes (the "Tribes") filed a lawsuit in the United States District Court for the District of Columbia ("District Court") challenging permits issued by the USACE permitting 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 allowing the pipeline to cross land owned by the USACE adjacent to the Missouri River. As a result of this litigation, the District Court vacated the easement, ordered USACE to prepare an Environmental Impact Statement ("EIS"), and order the pipeline shutdown and drained of oil. Dakota Access and USACE appealed this decision and moved for a stay of the District Court's orders. On August 5, 2020, the Court of Appeals 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, but the Court of Appeals denied a stay of the easement vacatur. The August 5, 2020 order also stated that the Court of Appeals expected the USACE to clarify its position with respect to whether USACE intends 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. Following this order, the Tribes filed a motion with the District Court seeking an injunction to prevent the continued operation of the pipeline. On January 26, 2021, the Court of Appeals affirmed the District Court's order requiring an EIS and its order vacating the easement. In the same January 26 order, the Court of Appeals also overturned the District Court's July 6, 2020 order that the pipeline be shut down and emptied of oil because of the lack of findings sufficient to satisfy the legal requirements for injunctive relief, including a finding of irreparable harm to the Tribes in the absence of an injunction. 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 and Plaintiffs and Dakota Access has filed their reply.

The District Court scheduled a status conference for February 10, 2021 to discuss the impact of the Court of Appeals' ruling on the pending motion for injunctive relief, as well as USACE's expectations as to how it will proceed in light of the Court of Appeals' recent vacatur ruling. USACE filed a motion for a continuance of the status conference until April 9, 2021, and this motion was approved by the District Court on February 9, 2021. Dakota Access and the Tribes filed their supplemental declarations on April 19, 2021 and April 26, 2021, respectively. On April 26, 2021, the District Court requested that USACE advise it by May 3, 2021 as to USACE's current position, if it has one, with respect to the motion. On May 3, 2021, USACE advised the District Court that it had not changed its position with respect to its opposition to the Tribes' motion for injunction. The USACE also advised the District Court that it expected that the EIS will be completed by March 2022. On May 21, 2021 the District Court denied the Plaintiffs' request for an injunction. The District Court further directed the parties to file a joint status report by June 11, 2021 concerning potential next steps in the litigation. On June 22, 2021, the District Court terminated the consolidated lawsuits and dismissed all remaining outstanding counts without prejudice. The USACE now estimates that the EIS will be complete by the end of 2022. For further information, see Note 11 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" in this report.

Our interstate natural gas pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services, which may prevent us from fully recovering our costs.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of our interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs.

We are required to file with the FERC tariff rates (also known as recourse rates) that shippers may pay for interstate natural gas transportation services. We may also agree to discount these rates on a not unduly discriminatory basis or negotiate rates with shippers who elect not to pay the recourse rates. The FERC must approve or accept all rate filings for us to be allowed to charge such rates.

The FERC may review existing tariff rates on its own initiative or upon receipt of a complaint filed by a third party. The FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. The FERC has recently exercised this authority with respect to several other pipeline companies. If the FERC were to initiate a proceeding against us and find that our rates were not just and reasonable or were unduly discriminatory, the maximum rates we are permitted to charge may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

The costs of our interstate pipeline operations may increase, and we may not be able to recover all of those costs due to FERC regulation of our rates. If we propose to change our tariff rates, our proposed rates may be challenged by the FERC or third parties, and the FERC may deny, modify or limit our proposed changes if we are unable to persuade the FERC that changes would result in just and reasonable rates that are not unduly discriminatory. We also may be limited by the terms of rate case settlement agreements or negotiated rate agreements with individual customers from seeking future rate increases, or we may be constrained by competitive factors from charging our tariff rates.

To the extent our costs increase in an amount greater than our revenues increase, or there is a lag between our cost increases and our ability to file for and obtain rate increases, our operating results would be negatively affected. Even if a rate increase is permitted by the FERC to become effective, the rate increase may not be adequate. We cannot guarantee that our interstate pipelines will be able to recover all of our costs through existing or future rates.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before the FERC and the courts for a number of years. 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 ("ROE") 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 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 individual entities' 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 impacts that FERC's policy on the treatment of income taxes may have on the rates an interstate pipeline held in a tax-pass-through entity can charge for the FERC regulated transportation services are unknown at this time.

Even without application of FERC's recent rate making-related policy statements and rulemakings, under the NGA, 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 rate. Moreover, we receive revenues from our pipelines based on a variety of rate structures, including cost-of-service rates, negotiated rates, discounted rates and market-based rates. Many of our interstate pipelines, such as ETC Tiger, Midcontinent Express and Fayetteville Express, have negotiated market rates that were agreed to by customers in connection with long-term contracts entered into to support the construction of the pipelines. Other systems, such as FGT, Transwestern and Panhandle, have a mix of tariff rate, discount rate, and negotiated rate agreements. The revenues we receive from natural gas transportation services we provide pursuant to cost-of-service based rates may decrease in the future as a result of 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 a pipeline's cost-of-service components and the outcomes of any challenges to our rates by the FERC or our shippers.

By the 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.

Our interstate natural gas pipelines are subject to laws, regulations and policies governing terms and conditions of service, which could adversely affect our business and results of operations.

In addition to rate oversight, the FERC's regulatory authority extends to many other aspects of the business and operations of our interstate natural gas pipelines, including:

- terms and conditions of service;
- the types of services interstate pipelines may or must offer their customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. In addition, we cannot guarantee that the FERC will authorize tariff changes and other activities we might propose and to undertake in a timely manner and free from potentially burdensome conditions. Future changes to laws, regulations, policies and interpretations thereof may impair our access to capital markets or may impair the ability of our interstate pipelines to compete for business, may impair their ability to recover costs or may increase the cost and burden of operation.

The FERC issued a Notice of Inquiry ("NOI") on April 19, 2018 ("2018 NOI") 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 (“1999 Policy Statement”), 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. 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. The FERC has not taken any further action regarding the 2018 NOI, 2021 NOI, or Technical Conference on Greenhouse Gas Mitigation, and we are unable to predict what, if any, changes may be proposed as a result of the NOIs or following the technical conference that might affect our natural gas pipeline or LNG facility operations, or when such proposals, if any, might become effective. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline company operating in the United States.

Rate regulation or market conditions may not allow us to recover the full amount of increases in the costs of our crude oil, NGL and refined products pipeline operations.

Transportation provided on our common carrier interstate crude oil, NGL and refined products pipelines is subject to rate regulation by the FERC, which requires that tariff rates for transportation on these oil pipelines be just and reasonable and not unduly discriminatory. If we propose new or changed rates, the FERC or interested persons may challenge those rates and the FERC is authorized to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the proposed rate is unjust or unreasonable, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The primary ratemaking methodology used by the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. The FERC’s ratemaking methodologies may limit our ability to set rates based on our costs or may delay the use of rates that reflect increased costs. On March 25, 2020, the FERC issued a Notice of Inquiry seeking comment on a proposal to change the preliminary screen for complaints against oil pipeline index rate increases to a “Percentage Comparison Test” consistent with the preliminary screen used by the FERC for protests against oil pipeline index rate increases. The FERC also requested comment on whether the appropriate threshold for the screen is a 10% or more differential between a proposed index rate increase and the annual percentage change in cost of service reported by the pipeline. Initial comments were due June 16, 2020, and reply comments were due July 16, 2020. The FERC has not yet taken any further action on the Notice of Inquiry. At this time, we cannot determine the effect of a change in the FERC’s preliminary screen for complaints against index rates changes, however, a revised screen would result in a threshold aligned with the existing threshold for protests against index rate increases. Any complaint or protest raised by a shipper could materially and adversely affect our financial condition, results of operations or cash flows.

On June 18, 2020, FERC issued a NOI requesting comments on a proposed oil pipeline index for the five-year period commencing July 1, 2021 and ending June 30, 2026, and requested comments on whether and how the index should reflect the Revised Policy Statement and FERC’s treatment of accumulated deferred income taxes as well as FERC’s revised ROE methodology.

On December 17, 2020, FERC issued an order establishing a new index of PPI-FG plus 0.78%. The Commission received requests for rehearing of its December 17, 2020 order and on January 20, 2022, granted rehearing and modified the oil index. Specifically, for the five-year period commencing July 1, 2021 and ending June 30, 2026, FERC-regulated liquids pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI-FG minus 0.21%. FERC directed liquids pipelines to recompute their ceiling levels for July 1, 2021 through June 30, 2022 based on the new index level. Where an oil pipeline’s filed rates exceed its ceiling levels, FERC ordered such oil pipelines to reduce the rate to bring it into compliance with the recomputed ceiling level to be effective March 1, 2022.

Under the Energy Policy Act of 1992 (the “Energy Policy Act”), certain interstate pipeline rates were deemed just and reasonable or “grandfathered.” Revenues are derived from such grandfathered rates on most of our FERC-regulated pipelines. A person challenging a grandfathered rate must, as a threshold matter, establish a substantial change since the date of enactment of the Energy Policy Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. If the FERC were to find a substantial change in circumstances, then the existing rates could be subject to detailed review and there is a risk that some rates could be found to be in excess of levels justified by the pipeline’s costs. In such event, the FERC could order us to reduce pipeline rates prospectively and to pay refunds to shippers.

If the FERC's petroleum pipeline ratemaking methodologies procedures changes, the new methodology or procedures could adversely affect our business and results of operations.

State regulatory measures could adversely affect the business and operations of our midstream and intrastate pipeline and storage assets.

Our midstream and intrastate transportation and storage operations are generally exempt from FERC regulation under the NGA, but FERC regulation still significantly affects our business and the market for our products. The rates, terms and conditions of service for the interstate services we provide in our intrastate gas pipelines and gas storage are subject to FERC regulation under Section 311 of the NGPA. Our HPL System, Trans-Pecos, Pelico pipeline, Red Bluff Express, Regency Intrastate, Lobo pipeline, Comanche Trail pipeline, ETC Katy pipeline, Oasis pipeline and ET Fuel System provide such services. Under Section 311, rates charged for transportation and storage must be fair and equitable. Amounts collected in excess of fair and equitable rates are subject to refund with interest, and the terms and conditions of service, set forth in the pipeline's statement of operating conditions, are subject to FERC review and approval. Should the FERC determine not to authorize rates equal to or greater than our costs of service, our cash flow would be negatively affected.

Our midstream and intrastate gas and oil transportation pipelines and our intrastate gas storage operations are subject to state regulation. All of the states in which we operate midstream assets, intrastate pipelines or intrastate storage facilities have adopted some form of complaint-based regulation, which allow producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to the fairness of rates and terms of access. The states in which we operate have ratable take statutes, which generally require gatherers to take, without undue discrimination, production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Should a complaint be filed in any of these states or should regulation become more active, our business may be adversely affected.

Our intrastate transportation operations located in Texas are also subject to regulation as gas utilities by the TRRC. Texas gas utilities must publish the rates they charge for transportation and storage services in tariffs filed with the TRRC, although such rates are deemed just and reasonable under Texas law unless challenged in a complaint.

We are subject to other forms of state regulation, including requirements to obtain operating permits, reporting requirements, and safety rules (see description of federal and state pipeline safety regulation below). Violations of state laws, regulations, orders and permit conditions can result in the modification, cancellation or suspension of a permit, civil penalties and other relief.

Certain of our assets may become subject to regulation.

The distinction between federally unregulated gathering facilities and FERC-regulated transmission pipelines under the NGA has been the subject of extensive litigation and may be determined by the FERC on a case-by-case basis, although the FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of our gathering facilities could change based on future determinations by the FERC, the courts or Congress. If our gas gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. Lone Star's NGL Pipeline transports NGLs within the state of Texas and is subject to regulation by the TRRC. This NGLs transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. In 2013, Lone Star's NGL pipeline also commenced the interstate transportation of NGLs, which is subject to the FERC's jurisdiction under the Interstate Commerce Act ("ICA") and the Energy Policy Act. Both intrastate and interstate NGL transportation services must be provided in a manner that is just, reasonable, and non-discriminatory. The tariff rates established for interstate services were based on a negotiated agreement; however, if the FERC's ratemaking methodologies were imposed, they may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. In addition, the rates, terms and conditions for shipments of crude oil, petroleum products and NGLs on our pipelines are subject to regulation by the FERC if the NGLs are transported in interstate or foreign commerce, whether by our pipelines or other means of transportation. Since we do not control the entire transportation path of all crude oil, petroleum products and NGLs on our pipelines, FERC regulation could be triggered by our customers' transportation decisions.

In addition, if any of our pipelines were found to have provided services or otherwise operated in violation of the NGA, NGPA, or ICA, this could result in the imposition of administrative and criminal remedies and civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to authority under the NGPSA and HLPSA, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for natural gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas ("HCAs") which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources, and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. Any changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, in October 2019, PHMSA published the first of three regulations relating to new or more stringent requirements for certain natural gas lines and gathering lines, that had originally been proposed in 2016 as part of PHMSA's "Gas Megarule." The rulemaking imposed numerous requirements on onshore gas transmission pipelines relating to MAOP, reconfirmation and exceedance reporting, the integrity assessment of additional pipeline mileage found in MCAs, non-HCAs, Class 3 and Class 4 areas by 2023, and the consideration of seismicity as a risk factor in integrity management. PHMSA's second final rule, applicable to hazardous liquid transmission and gathering pipelines, significantly extended and expanded the reach of certain integrity management requirements, use of in-line inspection tools by 2039 (unless the pipeline cannot be modified to permit such use), increased annual, accident, and safety-related conditional reporting requirements, and expanded use of leak detection systems beyond HCAs. The changes adopted by these rulemakings could have a material adverse effect on our results of operations and costs of transportation services.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The NGPSA and HLPSA were amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"). Among other things, the 2011 Pipeline Safety Act increased the penalties for safety violations and directed the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm that the material strength of certain pipelines are above 30% of specified minimum yield strength, and operator verification of records confirming the MAOP of certain interstate natural gas transmission pipelines. In May 2021, PHMSA issued a final rule increasing the maximum administrative fines for safety violations were increased to account for inflation, with maximum civil penalties set at $225,134 per day, with a maximum of $2,251,334 for a series of violations. Upon reauthorization of PHMSA, Congress often directs the agency to complete certain rulemakings. For example, in the Consolidated Appropriations Bill for Fiscal Year 2021, Congress reauthorized PHMSA through fiscal year 2023 and directed the agency to move forward with several regulatory actions, including the "Pipeline Safety: Class Location Change Requirements" and the "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" proposed rulemaking, To that end, in addition to the two final rules discussed above, PHMSA issued a third final rule significantly expanding reporting and safety requirements of operators of gas gathering pipelines, imposing safety regulations on approximately 400,000 miles of previously unregulated onshore gas gathering lines that, among other things, will impose criteria for inspection and repair of fugitive emissions, extend reporting requirements to all gas gathering operators, and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. Additionally, in June 2021, PHMSA issued an Advisory Bulletin advising pipeline and pipeline facility operators of applicable requirements to update their inspection and maintenance plans for the elimination of hazardous leaks and minimization of natural gas from related pipeline facilities. The safety enhancement requirements and other provisions of Congressional mandates to PHMSA, as well as any implementation of PHMSA rules thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto, could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial condition.

Our business involves the generation, handling and disposal of hazardous substances, hydrocarbons and wastes which activities are subject to environmental and worker health and safety laws and regulations that may cause us to incur significant costs and liabilities.

Our business is subject to stringent federal, tribal, state, and local laws and regulations governing the discharge of materials into the environment, worker health and safety and protection of the environment. These laws and regulations may require the acquisition of permits for the construction and operation of our pipelines, plants and facilities, result in capital expenditures to manage, limit or prevent emissions, discharges or releases of various materials from our pipelines, plants and facilities, impose specific health and safety standards addressing worker protection, and impose substantial liabilities for pollution resulting from our construction and operations activities. Several governmental authorities, such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them and frequently mandate difficult and costly remediation measures and other actions. Failure to comply with these laws, regulations and permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of investigatory remedial and corrective action obligations, the occurrence of delays in permitting and completion of projects, and the issuance of injunctive relief. For example, following an inadvertent return that occurred in connection with the construction of our Mariner East 2 pipeline (“Mariner 2”), the Pennsylvania Department of Environmental Protection (“PADEP”) in September 2020 ordered the rerouting of a section of Mariner 2. We challenged this order, however, in December 2021, PADEP, alongside the Department of Conservation and Natural Resources, jointly fined the Mariner 2 project and imposed additional work on a separate project where construction had caused an accidental spill. Any additional requirements from the PADEP regarding Mariner 2 or other of our pipeline projects may result in delays in the completion of these projects.

Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or released, even under circumstances where the substances, hydrocarbons or wastes have been released by a predecessor operator. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property and natural resource damage allegedly caused by noise, odor or the release of hazardous substances, hydrocarbons or wastes into the environment.

We may incur substantial environmental costs and liabilities because of the underlying risk arising out of our operations. Although we have established financial reserves for our estimated environmental remediation liabilities, additional contamination or conditions may be discovered, resulting in increased remediation costs, liabilities or natural resource damages that could substantially increase our costs for site remediation projects. Accordingly, we cannot assure you that our current reserves are adequate to cover all future liabilities, even for currently known contamination.

Uncertainty about the future course of regulation continues to exist following the change in U.S. presidential administrations in January 2021. Upon taking office, the Biden Administration issued an executive order directing all federal agencies to review and take action to address any federal regulations promulgated during the prior administration that may be inconsistent with the current administration’s policies. As a result, several regulatory developments have occurred, but it remains unclear the degree to which this will continue . The executive order also established a Working Group that is called on to, among other things, develop methodologies for calculating the “social cost of carbon,” “social cost of nitrous oxide” and “social cost of methane.” During 2021, the Working Group published interim estimates of the social costs of carbon, methane, and nitrous oxide and sought public comment on these estimates. The Working Group’s final recommendations are expected in early 2022. Further regulation of air emissions, as well as uncertainty regarding the future course of regulation, could eventually reduce the demand for oil and natural gas and, in turn, have a material adverse effect on our business, financial condition or results of operations.

Changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, emission standards, or storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. For example, in October 2015, the EPA published a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards, and the EPA finalized its attainment/non-attainment designations in 2018, though these are subject to change. In December 2020, the EPA announced that it was retaining without revision the 2015 NAAQS for ozone. However, the Biden Administration has announced plans to formally review this decision and consider instituting a more stringent standard. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our customers’ operations. Compliance with this final rule or any other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines or new restrictions or prohibitions with respect to permits or projects, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. Historically, we have been able to satisfy the more stringent nitrogen oxide emission reduction requirements that affect our compressor units in ozone non-attainment areas at reasonable cost, but there is no assurance that we will not incur material costs in the future to meet the new, more stringent ozone standard.

Regulations under the Clean Water Act, Oil Pollution Act of 1990, as amended ("OPA"), and state laws impose regulatory burdens on terminal operations. Spill prevention control and countermeasure requirements of federal and state laws require containment to mitigate or prevent contamination of waters in the event of a refined product overflow, rupture, or leak from above-ground pipelines and storage tanks. The Clean Water Act also requires us to maintain spill prevention control and countermeasure plans at our terminal facilities with above-ground storage tanks and pipelines. In addition, OPA requires that most fuel transport and storage companies maintain and update various oil spill prevention and oil spill contingency plans. Facilities that are adjacent to water require the engagement of Federally Certified Oil Spill Response Organizations to be available to respond to a spill on water from above-ground storage tanks or pipelines.

Transportation and storage of refined products over and adjacent to water involves risk and potentially subjects us to strict, joint, and potentially unlimited liability for removal costs and other consequences of an oil spill where the spill is into navigable waters, along shorelines or in the exclusive economic zone of the United States.

In the event of an oil spill into navigable waters, substantial liabilities could be imposed upon us. The Clean Water Act imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters, with the potential of substantial liability for the violation of permits or permitting requirements.

Terminal operations and associated facilities are subject to the Clean Air Act as well as comparable state and local statutes. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions, and operating permits may be required for sources that are already constructed. If regulations become more stringent, additional emission control technologies.

Climate change legislation or regulations restricting emissions of greenhouse gases ("GHGs") could result in increased operating costs and reduced demand for the services we provide.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the United States, no comprehensive climate change legislation has been implemented at the federal level to date. However, Canada has implemented a federal carbon pricing regime, and, in the United States, President Biden has announced that he intends to pursue substantial reductions in greenhouse gas emissions, particularly from the oil and gas sector. For example, on January 27, 2021, President Biden signed an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, an increase in the production of offshore wind energy, and an increased emphasis on climate-related risks across government agencies and economic sectors. Additionally, the EPA has adopted rules under authority of the Clean Air Act that, among other things, establish Potential for Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating GHG emissions, such as methane, from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and VOC emissions. These Subpart OOOOa standards expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. In September 2020, the EPA finalized amendments to Subpart OOOOa that rescind the methane limits for new, reconstructed and modified oil and natural gas production sources while leaving in place the general emission limits for VOCs. In addition, the rulemaking removes from the oil and natural gas category the natural gas transmission and storage segment. However, Congress passed, and President Biden signed into law, a revocation of the 2020 rulemaking, effectively reinstating the 2016 standards. Additionally, in November 2021, the EPA issued a proposed rule that, if finalized, would establish OOOOb new source and OOOOc first-time existing source standards of performance for GHG and VOC emissions for crude oil and natural gas well sites, natural gas gathering and boosting compressor stations, natural gas processing plants, and transmission and storage facilities, Owners or operators of affected emission units or processes would have to comply with specific standards of performance that may include leak detection using optical gas imaging and subsequent repair requirements, reduction of emissions by 95% through capture and control systems, zero-emission requirements, operations and maintenance requirements, and so-called “green well” completion requirements. The EPA plans to issue a supplemental proposal enhancing this proposed rulemaking in 2022 that will contain proposed rule text, which was not included in the November 2021 proposed rule, and anticipates issuing a final rule by the end of 2022. Several states have also adopted, or are considering, adopting, regulations related to GHG emissions, some of which are more stringent than those implemented by the federal government. Methane emission standards imposed on the oil and gas sector could result in increased costs to our operations or those of our customers as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

At the international level, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France in signing the “Paris Agreement,” a treaty that requires member countries to submit individually-determined, non-binding GHG emission reduction goals every five years beginning in 2020. Although the United States withdrew from the Agreement under the Trump administration, President Biden recommitted the United States in February 2021, and, in April 2021, announced a new, more rigorous nationally determined emissions reduction level of 50-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. The international community gathered again in Glasgow in November 2021 at COP26 during which multiple announcements were made, including a call for parties to eliminate fossil fuel subsidies, amongst other measures. Relatedly, the United States and European Union jointly announced at COP26 the launch of the Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including “all feasible reductions” in the energy sector.

President Biden’s January 2021 climate change executive order also directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands or in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices, consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs. The executive order also directed the federal government to identify “fossil fuel subsidies” to take steps to ensure that, to the extent consistent with applicable law, federal funding is not directly subsidizing fossil fuels. As noted above, a separate executive order issued in January 2021 established a Working Group that is called on to, among other things, develop methodologies for calculating the “social cost of carbon,” “social cost of nitrous oxide” and “social cost of methane.” During 2021, the Working Group published interim estimates of the social costs of carbon, methane, and nitrous oxide and sought public comment on these estimates. The Working Group’s final recommendations are expected in early 2022. It is difficult to predict how these measures may impact our business; however, any new restrictions on oil and gas permitting or leasing on federal lands could discourage new oil and gas development by our customers, which could have an adverse effect on our business.

The adoption, strengthening and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows. Litigation risks are also increasing, as several oil and gas companies have been sued for allegedly causing climate-related damages due to their production and sale of fossil fuel products or for allegedly being aware of the impacts of climate change for some time but failing to adequately disclose such risks to their investors or customers.

There are also increasing financing risks for fossil fuel energy companies, as various investors become increasingly concerned about the potential effects of climate change and may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing for fossil fuel energy companies also have become more attentive to sustainable lending practices that favor “clean” power sources such as wind and solar photovoltaic, making those sources more attractive for investment, and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the GFANZ announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero by 2050. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding for fossil fuel energy companies. In late 2020, the Federal Reserve announced that it has joined NGFS, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. More recently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Such efforts could make it more difficult for exploration and production companies and midstream companies, like us, to secure funding as well as negatively affect the cost of, and terms for, financings to fund growth projects or other aspects of our business. Additionally, the SEC announced its intention to promulgate rules requiring climate disclosures. Although the form and substance of these requirements is not yet known, this may result in additional costs to comply with any such disclosure requirements.

Climatic events in the areas in which we operate, whether from climate change or otherwise, can cause disruptions, and in some cases, delays in, or suspension of, our services. These event, including but not limited to drought, winter storms, wildfire, extreme temperatures or flooding, may become more intense or more frequent as a result of climate change and could have an adverse effect on our continued operations. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities or our customers' facilities from powerful winds or rising waters. We may experience increased insurance costs, or difficulty obtaining adequate insurance coverage, for our assets in areas subject to more frequent severe weather. We may not be able to recoup these increased costs through the rates we charge our customers. Extreme weather events could cause damage to property or facilities that could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our NGLs and natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we transport, and thus demand for our services. Despite the use of the term "global warming" as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our products could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

A climate-related decrease in demand for crude oil, natural gas and other hydrocarbon products could negatively affect our business.

Supply and demand for crude oil, natural gas and other hydrocarbon products we handle is dependent upon a variety of factors, many of which are beyond our control. These factors include, among others, the potential adoption of new government regulations, including those related to fuel conservation measures and climate change regulations, technological advances in fuel economy and energy generation devices. For example, legislative, regulatory or executive actions intended to reduce emissions of GHGs could increase the cost of consuming crude oil, natural gas and other hydrocarbon products, thereby potentially causing a reduction in the demand for such products. A broader transition to alternative fuels or energy sources, whether resulting from potential new government regulation, carbon taxes or consumer preferences could result in decreased demand for hydrocarbon products like crude oil, natural gas and NGLs that we handle. Any decrease in demand for these products could consequently reduce demand for our services and could have a negative effect on our business.

Increased attention to ESG matters and conservation measures may adversely impact our business.

Increasing attention to, and societal expectations on companies to address, climate change and other environmental and social impacts, investor and societal expectations regarding voluntary ESG disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for fossil fuels and consequently demand for our midstream services, reduced profits, increased risk of investigations and litigation, and negative impacts on the value of our assets and access to capital. Increasing attention to climate change and environmental conservation, for example, may result in reduced demand for oil and natural gas products and additional governmental investigations and private litigation against us or our customers. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to climate change or asserted damage to the environment, or to other mitigating factors. While we may participate in various voluntary frameworks and certification programs to improve the ESG profile of our operations and products, we cannot guarantee that such participation or certification will have the intended results on our ESG profile.

Moreover, while we create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures will be based on expectations and assumptions. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring, and reporting on many ESG matters. Additionally, while we may also announce various voluntary ESG targets in the future, such targets are aspirational. We may not be able to meet such targets in the manner or on such a timeline as initially contemplated, including, but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such results. To the extent that we do meet such targets, we may consider the acquisition of various credits or offsets that may be deemed to assist in the achievement of such targets or otherwise mitigate our ESG impact instead of actual achievements of such targets or actual changes in our ESG performance. Also, despite these aspirational goals, we may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Additionally, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, which may adversely affect our operations.

Such ESG matters may also impact our customers or suppliers, which may adversely impact our business, financial condition, or results of operations.

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder could have an adverse effect on our ability to use derivative instruments to mitigate the risks of changes in commodity prices and interest rates and other risks associated with our business.

Provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) and rules adopted by the CFTC, the SEC and other prudential regulators establish federal regulation of the physical and financial derivatives, including over-the-counter derivatives market and entities, such as us, participating in that market. While most of these regulations are already in effect, the implementation process is still ongoing and the CFTC continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, any new regulations or modifications to existing regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability and/or liquidity of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. Any of these consequences could have a material adverse effect on our financial condition, results of operations and cash available for distribution to our Unitholders.

The CFTC has re-proposed speculative position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, although certain bona fide hedging transactions would be exempt from these position limits provided that various conditions are satisfied. The CFTC has also finalized a related aggregation rule that requires market participants to aggregate their positions with certain other persons under common ownership and control, unless an exemption applies, for purposes of determining whether the position limits have been exceeded. If adopted, the revised position limits rule and its finalized companion rule on aggregation may create additional implementation or operational exposure. In addition to the CFTC federal speculative position limit regime, designated contract markets (“DCMs”) also maintain speculative position limit and accountability regimes with respect to contracts listed on their platform as well as aggregation requirements similar to the CFTC’s final aggregation rule. Any speculative position limit regime, whether imposed at the federal-level or at the DCM-level may impose added operating costs to monitor compliance with such position limit levels, addressing accountability level concerns and maintaining appropriate exemptions, if applicable.

The Dodd-Frank Act requires that certain classes of swaps be cleared on a derivatives clearing organization and traded on a DCM or other regulated exchange, unless exempt from such clearing and trading requirements, which could result in the application of certain margin requirements imposed by derivatives clearing organizations and their members. The CFTC and prudential regulators have also adopted mandatory margin requirements for uncleared swaps entered into between swap dealers and certain other counterparties. We currently qualify for and rely upon an end-user exception from such clearing and margin requirements for the swaps we enter into to hedge our commercial risks. However, the application of the mandatory clearing and trade execution requirements and the uncleared swaps margin requirements to other market participants, such as swap dealers, may adversely affect the cost and availability of the swaps that we use for hedging.

In addition to the Dodd-Frank Act, the European Union and other foreign regulators have adopted and are implementing local reforms generally comparable with the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with non-U.S. counterparties and may make transactions involving cross-border swaps more expensive and burdensome. Additionally, the lack of regulatory equivalency across jurisdictions may increase compliance costs and make it more difficult to satisfy our regulatory obligations.

Additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration, development, oil spill-response and decommissioning plans, and other related developments may have a material adverse effect on our business, financial condition, or results of operations.

The Federal Bureau of Ocean Energy Management (“BOEM”) and the federal Bureau of Safety and Environmental Enforcement (“BSEE”), each agencies of the DOI, have imposed more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these more stringent regulatory requirements and with existing environmental and oil spill regulations, together with any uncertainties or inconsistencies in decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts. For instance, in January 2021, the Biden Administration issued an executive order focused on climate change that, among other things, directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands or in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices, consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs.

In addition, new regulatory initiatives may be adopted or enforced by the BOEM or the BSEE in the future that could result in additional costs, delays, restrictions, or obligations with respect to oil and natural gas exploration and production operations conducted offshore by certain of our customers. Separately, in October 2020, BOEM and BSEE published a proposed rule regarding financial assurance requirements for offshore leases, particularly regarding requirements for bonds above base amounts prescribed by regulation. At this time, we cannot determine with any certainty the amount of any additional financial assurance that may be ordered by BOEM and required of us in the future, or that such additional financial assurance amounts can be obtained. The final publication or implementation of this rule, as well as any new rules, regulations, or legal initiatives, could delay or disrupt our customers' operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, limit activities in certain areas, or cause our customers' to incur penalties, or shut-in production or lease cancellation. Also, if material spill events were to occur in the future, the United States or other countries could elect to issue directives to temporarily cease drilling activities offshore and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development. The overall costs imposed on our customers to implement and complete any such spill response activities or any decommissioning obligations could exceed estimated accruals, insurance limits, or supplemental bonding amounts, which could result in the incurrence of additional costs to complete. Separately, in January 2021, the Biden Administration issued orders temporarily suspending the issuance of new authorizations and suspending the issuance of new leases pending completion of a review of current practices, for oil and gas development on federal lands and waters. The suspension of these federal leasing activities prompted legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district judge in Louisiana in June 2021, effectively halting implementation of the leasing suspension. Relatedly, the DOI released its report on federal gas leasing and permitting practices in November 2021, referencing a number of recommendations and an overarching intent to modernize the federal oil and gas leasing program, including by adjusting royalty and bonding rates, prioritizing leasing in areas with known resource potential, and avoiding leasing that conflicts with recreation, wildlife habitat, conservation, and historical and cultural resources. Implementation of many of the recommendations in the DOI report will require Congressional action and we cannot predict the extent to which the recommendations may be implemented now or in the future, but restrictions on federal oil and gas activities have the potential to result in increased costs on us and our customers, decrease demand for our services on federal lands, and adversely impact our business and adversely impact our business. The Biden Administration also published an order calling for an increase in the production of offshore wind energy, which may impact the use of federal waters. We cannot predict with any certainty the full impact of any new laws or regulations on our customers' drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations. The occurrence of any one or more of these developments could result in decreased demand for our services, which could have a material adverse effect on our business as well as our financial position, results of operation and liquidity.

Our business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that we store and transport.

The petroleum products that we store and transport are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications could reduce our throughput volume, require us to incur additional handling costs or require the expenditure of significant capital. In addition, different product specifications for different markets impact the fungibility of products transported and stored in our pipeline systems and terminal facilities and could require the construction of additional storage to segregate products with different specifications. We may be unable to recover these costs through increased revenues.

In addition, our patented butane blending services are reliant upon gasoline vapor pressure specifications. Significant changes in such specifications could reduce butane blending opportunities, which would affect our ability to market our butane blending service licenses and which would ultimately affect our ability to recover the costs incurred to acquire and integrate our butane blending assets.

Risks Relating to Our Partnership Structure

Issuance of Limited Partner units or other classes of equity

We may issue an unlimited number of limited partner interests or other classes of equity without the consent of our Unitholders, which will dilute Unitholders' ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

Our partnership agreement allows us to issue an unlimited number of additional limited partner interests, including securities senior to the Common Units, without the approval of our Unitholders. The issuance of additional Common Units or other equity securities by us will have the following effects:

- our Unitholders' current proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each Common Unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding Common Unit and/or Preferred Unit may be diminished; and
- the market price of our Common Units and/or Preferred Units may decline.

Cash Distributions to Unitholders and Governance

Cash distributions are not guaranteed and may fluctuate with our performance and other external factors.

The amount of cash we can distribute to our Unitholders depends upon the amount of cash we generate from our operations and from our subsidiaries, Sunoco LP and USAC. The amount of cash we generate from our operations will fluctuate from quarter to quarter and will depend upon, among other things:

- the amount of natural gas, NGLs, crude oil and refined products transported in our pipelines;
- the level of throughput in our processing and treating operations;
- the fees we charge and the margins we realize for our services;
- the price of natural gas, NGLs, crude oil and refined products;
- the relationship between natural gas, NGL and crude oil prices;
- the weather in our operating areas;
- the level of competition from other midstream, transportation and storage and other energy providers;
- the level of our operating costs;
- prevailing economic conditions; and
- the level and results of our derivative activities.

In addition, the actual amount of cash we and our subsidiaries, including Sunoco LP and USAC, will have available for distribution will also depend on other factors, such as:

- the level of capital expenditures we and our subsidiaries make;
- the level of costs related to litigation and regulatory compliance matters;
- the cost of acquisitions, if any;
- the levels of any margin calls that result from changes in commodity prices;
- our and our subsidiaries' debt service requirements;
- fluctuations in our and our subsidiaries' working capital needs;
- our and our subsidiaries' ability to borrow under our revolving credit facility;
- our and our subsidiaries' ability to access capital markets;
- restrictions on distributions contained in our and our subsidiaries' debt agreements; and
- the amount of cash reserves established by our general partner in its discretion for the proper conduct of our business.

Because of all these factors, we cannot guarantee that in the future we will be able to pay distributions or that any distributions we do make will be at or above our current quarterly distribution. The actual amount of cash that is available for distribution to our Unitholders will depend on numerous factors, many of which are beyond our control or the control of our general partner.

Furthermore, our Unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and is not solely a function of profitability, which is affected by non-cash items. As a result, we may declare and/or pay cash distributions during periods when we record net losses.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to Unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to Unitholders.

Unitholders may have liability to repay distributions.

Under certain circumstances, Unitholders may have to repay us amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to Unitholders if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated Delaware law, will be liable to the limited partnership for the distribution amount for three years from the distribution date.

The NYSE does not require a publicly traded partnership like us to comply with certain corporate governance requirements.

We have preferred units that are listed on the NYSE. Because we are a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, our Unitholders do not have the same protections afforded to stockholders of corporations that are subject to all of the corporate governance requirements of the applicable stock exchange.

Our General Partner

The control of our general partner may be transferred to a third party without Unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of the Unitholders. Any new owner of the general partner would be in a position to replace the officers and directors of the general partner with its own designees and thereby exert significant influence over the decisions made by such officers and directors.

The majority owner of our general partner has rights that protect him against dilution.

Through his controlling interest in our general partner, Kelcy Warren owns all of the outstanding Energy Transfer Class A Units, which represents an approximately 20% voting interest in the Partnership. Under the terms of the Energy Transfer Class A Units, upon the issuance by the Partnership of additional common units or any securities that have voting rights that are pari passu with the Partnership common units, the Partnership will issue to the general partner additional Energy Transfer Class A Units such that Mr. Warren maintains a voting interest in the Partnership that is equivalent to his voting interest in the Partnership with respect to such Energy Transfer Class A Units (approximately 20%) prior to such issuance of common units. As a result, Mr. Warren is partially protected against the dilutive effect of additional common unit issuances by the Partnership with respect to voting. As of December 31, 2021, the Partnership had outstanding 762,944,469 Energy Transfer Class A Units.

Cost reimbursements due to our general partner may be substantial and may reduce our ability to pay the distributions to Unitholders.

Prior to making any distributions to our Unitholders, we will reimburse our general partner for all expenses it has incurred on our behalf. In addition, our general partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by the general partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the Unitholders. Our general partner has sole discretion to determine the amount of these expenses and fees.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, our common unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our Unitholders have no right to elect our general partner or the board of directors of our general partner. Our general partner has the right to appoint and replace the members of the board, including all of its independent directors. Mr. Warren owns an 81.2% membership interest in our general partner and controls our general partner and therefore has the ability to direct our general partner with respect to the exercise of these governance rights.

If our Unitholders are dissatisfied with the general partner's performance, they have limited ability to remove the general partner. The vote of the holders of at least 66 2/3% of all outstanding common units is required to remove the general partner; however, Mr. Warren owns a significant number of common units and, through his controlling interest in the general partner, owns all of the outstanding Energy Transfer Class A Units, which vote together with the common units and entitle the holders of the Energy Transfer Class A Units to maintain the voting percentage in Energy Transfer represented by such Energy Transfer Class A Units as of the date the initial Energy Transfer Class A Units were issued (approximately 20%) any time new common units are issued. As of February 16, 2022, Mr. Warren's combined common unit and Energy Transfer Class A Unit ownership results in a voting interest in the Partnership of 27.1%. As a result of this and other limitations, it may be more difficult to remove the general partner.

Furthermore, our partnership agreement contains provisions limiting the ability of common unitholders to call meetings or to obtain information about our operations, as well as other provisions limiting our common unitholders' ability to influence the manner or direction of management. Common unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person or group that owns 20% or more of such class of units then outstanding, other than, with respect to our common units, the general partner, its affiliates, their direct transferees and their indirect transferees approved by our general partner (which approval may be granted in its sole discretion) and persons who acquired such common units with the prior approval of the general partner, cannot vote on any matter.

Kelcy Warren owns a majority interest in, and controls, our general partner, and our general partner has sole responsibility for conducting our business and managing our operations. The general partner may have conflicts of interest with us and limited fiduciary duties, and it may favor its own interests to the detriment of us and our Unitholders.

Mr. Warren owns an 81.2% membership interest in, and therefore controls, the general partner and accordingly has the right to appoint and replace all of the officers and directors of the general partner. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our Unitholders, the directors and officers of the general partner also have a fiduciary duty to manage the general partner in a manner that is beneficial to its majority owner, Mr. Warren. Conflicts of interest will arise between the general partner and its owner, on the one hand, and us and our Unitholders, on the other hand. In resolving these conflicts of interest, the general partner may favor its own interests and the interests of its owner over our interests and the interests of our Unitholders.

Unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under the Energy Transfer partnership agreement constituted participation in the "control" of our business. Additionally, under Delaware law, our general partner has unlimited liability for the obligations of Energy Transfer, such as our debts and environmental liabilities, except for those contractual obligations of Energy Transfer that are expressly made without recourse to the general partner.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. Unitholders could have unlimited liability for obligations of the Partnership if a court or government agency determined that (i) we were conducting business in a state, but had not complied with that particular state's partnership statute; or (ii) a Unitholder's right to act with other Unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under the partnership agreement constituted "control" of our business.

Our general partner has a limited call right that may require Unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 90% of our outstanding units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, Unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2021, the directors and executive officers of our general partner owned approximately 13% of our Common Units.

Our Subsidiaries

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to pay distributions to our Unitholders and to service our debt depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. If we are unable to obtain funds from our subsidiaries, we may not be able to pay distributions to our Unitholders or to pay interest or principal on our debt when due.

The interruption of distributions to us from our operating subsidiaries and equity investees may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no business operations other than that of our operating subsidiaries. Our only significant assets are the equity interests we own in our operating subsidiaries and equity investees. As a result, we depend upon the earnings and cash flow of our operating subsidiaries and equity investees and any interruption of distributions to us may affect our ability to meet our obligations, including any obligations under our debt agreements, and to make distributions to our partners.

Our subsidiaries are not prohibited from competing with us.

Neither our partnership agreement nor the partnership agreements of our subsidiaries, including Sunoco LP and USAC, prohibit our subsidiaries from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, our subsidiaries may acquire, construct or dispose of any assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets.

Sunoco LP and USAC may issue additional common units, which may increase the risk that each Partnership will not have sufficient available cash to maintain or increase its per unit distribution level.

The partnership agreements of Sunoco LP and USAC allow each partnership to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by each respective partnership will have the following effects:

- unitholders' current proportionate ownership interest in each partnership will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of each partnership's common units may decline.

The payment of distributions on any additional units issued by Sunoco LP and USAC may increase the risk that either partnership may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations

A reduction in Sunoco LP's distributions will disproportionately affect the amount of cash distributions to which Energy Transfer is entitled.

Energy Transfer indirectly owns all of the incentive distribution rights ("IDRs") of Sunoco LP. These IDRs entitle the holder to receive increasing percentages of total cash distributions made by Sunoco LP as such entity reaches established target cash distribution levels as specified in its partnership agreement. Energy Transfer currently receives its pro rata share of cash distributions from Sunoco LP based on the highest sharing level of 50% in respect of the Sunoco LP IDRs.

A decrease in the amount of distributions by Sunoco LP to less than $0.65625 per unit per quarter would reduce Energy Transfer's percentage of the incremental cash distributions from Sunoco LP above $0.546875 per unit per quarter from 50% to 25%. As a result, any such reduction in quarterly cash distributions from Sunoco LP would have the effect of disproportionately reducing the amount of all distributions that Energy Transfer receives, based on its ownership interest in the IDRs as compared to cash distributions received from its Sunoco LP common units.

A significant decrease in demand for motor fuel, including increased consumer preference for alternative motor fuels or improvements in fuel efficiency, in the areas Sunoco LP serves would reduce their ability to make distributions to its unitholders.

For the year ended December 31, 2021, sales of refined motor fuels accounted for approximately 97% of Sunoco LP's total revenues and 77% of gross profit. A significant decrease in demand for motor fuel in the areas Sunoco LP serves could significantly reduce revenues and Sunoco LP's ability to make distributions to its unitholders, including Energy Transfer. Sunoco LP revenues are dependent on various trends, such as trends in commercial truck traffic, travel and tourism in their areas of operation, and these trends can change. Regulatory action, including government imposed fuel efficiency standards, may also affect demand for motor fuel. Because certain of Sunoco LP's operating costs and expenses are fixed and do not vary with the volumes of motor fuel distributed, their costs and expenses might not decrease ratably or at all should they experience such a reduction. As a result, Sunoco LP may experience declines in their profit margin if fuel distribution volumes decrease.

Any technological advancements, regulatory changes or changes in consumer preferences causing a significant shift toward alternative motor fuels could reduce demand for the conventional petroleum based motor fuels Sunoco LP currently sells. Additionally, a shift toward electric, hydrogen, natural gas or other alternative-power vehicles could fundamentally change customers' shopping habits or lead to new forms of fueling destinations or new competitive pressures.

New technologies have been developed and governmental mandates have been implemented to improve fuel efficiency, which may result in decreased demand for petroleum-based fuel. Any of these outcomes could result in fewer visits to Sunoco LP's convenience stores or independently operated commission agents and dealer locations, a reduction in demand from their wholesale customers, decreases in both fuel and merchandise sales revenue, or reduced profit margins, any of which could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to its unitholders.

Sunoco LP's financial condition and results of operations are influenced by changes in the prices of motor fuel, which may adversely impact margins, customers' financial condition and the availability of trade credit.

Sunoco LP's operating results are influenced by prices for motor fuel. General economic and political conditions, acts of war or terrorism and instability in oil producing regions, particularly in the Middle East and South America, could significantly impact crude oil supplies and petroleum costs. Significant increases or high volatility in petroleum costs could impact consumer demand for motor fuel and convenience merchandise. Such volatility makes it difficult to predict the impact that future petroleum costs fluctuations may have on Sunoco LP's operating results and financial condition. Sunoco LP is subject to dealer tank wagon pricing structures at certain locations further contributing to margin volatility. A significant change in any of these factors could materially impact both wholesale and retail fuel margins, the volume of motor fuel distributed or sold at retail, and overall customer traffic, each of which in turn could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to its unitholders.

Significant increases in wholesale motor fuel prices could impact Sunoco LP as some of their customers may have insufficient credit to purchase motor fuel from us at their historical volumes. Higher prices for motor fuel may also reduce access to trade credit support or cause it to become more expensive.

The industries in which Sunoco LP operates are subject to seasonal trends, which may cause its operating costs to fluctuate, affecting its cash flow.

Sunoco LP relies in part on customer travel and spending patterns and may experience more demand for gasoline in the late spring and summer months than during the fall and winter. Travel, recreation and construction are typically higher in these months in the geographic areas in which Sunoco LP or its commission agents and dealers operate, increasing the demand for motor fuel that they sell and distribute. Therefore, Sunoco LP's revenues and cash flows are typically higher in the second and third quarters of our fiscal year. As a result, Sunoco LP's results from operations may vary widely from period to period, affecting Sunoco LP's cash flow.

The dangers inherent in the storage and transportation of motor fuel could cause disruptions in Sunoco LP's operations and could expose them to potentially significant losses, costs or liabilities.

Sunoco LP stores motor fuel in underground and aboveground storage tanks. Sunoco LP transports the majority of its motor fuel in its own trucks, instead of by third-party carriers. Sunoco LP's operations are subject to significant hazards and risks inherent in transporting and storing motor fuel. These hazards and risks include, but are not limited to, traffic accidents, fires, explosions, spills, discharges, and other releases, any of which could result in distribution difficulties and disruptions, environmental pollution, governmentally-imposed fines or clean-up obligations, personal injury or wrongful death claims, and other damage to its properties and the properties of others. Any such event not covered by Sunoco LP's insurance could have a material adverse effect on its business, financial condition, results of operations and cash available for distribution to its unitholders.

Sunoco LP's fuel storage terminals are subject to operational and business risks which may adversely affect their financial condition, results of operations, cash flows and ability to make distributions to its unitholders.

Sunoco LP's fuel storage terminals are subject to operational and business risks, the most significant of which include the following:

- the inability to renew a ground lease for certain of their fuel storage terminals on similar terms or at all;
- the dependence on third parties to supply their fuel storage terminals;
- outages at their fuel storage terminals or interrupted operations due to weather-related or other natural causes;
- the threat that the nation's terminal infrastructure may be a future target of terrorist organizations;
- the volatility in the prices of the products stored at their fuel storage terminals and the resulting fluctuations in demand for storage services;
- the effects of a sustained recession or other adverse economic conditions;
- the possibility of federal and/or state regulations that may discourage their customers from storing gasoline, diesel fuel, ethanol and jet fuel at their fuel storage terminals or reduce the demand by consumers for petroleum products;
- competition from other fuel storage terminals that are able to supply their customers with comparable storage capacity at lower prices; and
- climate change legislation or regulations that restrict emissions of GHGs could result in increased operating and capital costs and reduced demand for our storage services.

The occurrence of any of the above situations, amongst others, may affect operations at their fuel storage terminals and may adversely affect Sunoco LP's business, financial condition, results of operations, cash flows and ability to make distributions to its unitholders.

Negative events or developments associated with Sunoco LP's branded suppliers could have an adverse impact on its revenues.

Sunoco LP believes that the success of its operations is dependent, in part, on the continuing favorable reputation, market value, and name recognition associated with the motor fuel brands sold at Sunoco LP's convenience stores and at stores operated by its independent, branded dealers and commission agents. Erosion of the value of those brands could have an adverse impact on the volumes of motor fuel Sunoco LP distributes, which in turn could have a material adverse effect on its business, financial condition, results of operations and ability to make distributions to its unitholders.

Sunoco LP currently depends on a limited number of principal suppliers in each of its operating areas for a substantial portion of its merchandise inventory and its products and ingredients for its food service facilities. A disruption in supply or a change in either relationship could have a material adverse effect on its business.

Sunoco LP currently depends on a limited number of principal suppliers in each of its operating areas for a substantial portion of its merchandise inventory and its products and ingredients for its food service facilities. If any of Sunoco LP's principal suppliers elect not to renew their contracts, Sunoco LP may be unable to replace the volume of merchandise inventory and products and ingredients currently purchased from them on similar terms or at all in those operating areas. Further, a disruption in supply or a significant change in Sunoco LP's relationship with any of these suppliers could have a material adverse effect on Sunoco LP's business, financial condition and results of operations and cash available for distribution to its unitholders.

The wholesale motor fuel distribution industry and convenience store industry are characterized by intense competition and fragmentation and impacted by new entrants. Failure to effectively compete could result in lower margins.

The market for distribution of wholesale motor fuel is highly competitive and fragmented, which results in narrow margins. Sunoco LP has numerous competitors, some of which may have significantly greater resources and name recognition than it does. Sunoco LP relies on its ability to provide value-added, reliable services and to control its operating costs in order to maintain our margins and competitive position. If Sunoco LP fails to maintain the quality of its services, certain of its customers could choose alternative distribution sources and margins could decrease. While major integrated oil companies have generally continued to divest retail sites and the corresponding wholesale distribution to such sites, such major oil companies could shift from this strategy and decide to distribute their own products in direct competition with Sunoco LP, or large customers could attempt to buy directly from the major oil companies. The occurrence of any of these events could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to its unitholders.

The geographic areas in which Sunoco LP operates and supplies independently operated commission agent and dealer locations are highly competitive and marked by ease of entry and constant change in the number and type of retailers offering products and services of the type we and our independently operated commission agents and dealers sell in stores. Sunoco LP competes with other convenience store chains, independently owned convenience stores, motor fuel stations, supermarkets, drugstores, discount stores, dollar stores, club stores, mass merchants and local restaurants. Over the past two decades, several non-traditional retailers, such as supermarkets, hypermarkets, club stores and mass merchants, have impacted the convenience store industry, particularly in the geographic areas in which Sunoco LP operates, by entering the motor fuel retail business. These non-traditional motor fuel retailers have captured a significant share of the motor fuels market, and Sunoco LP expects their market share will continue to grow.

In some of Sunoco LP's markets, its competitors have been in existence longer and have greater financial, marketing, and other resources than they or their independently operated commission agents and dealers do. As a result, Sunoco LP's competitors may be able to better respond to changes in the economy and new opportunities within the industry. To remain competitive, Sunoco LP must constantly analyze consumer preferences and competitors' offerings and prices to ensure that they offer a selection of convenience products and services at competitive prices to meet consumer demand. Sunoco LP must also maintain and upgrade our customer service levels, facilities and locations to remain competitive and attract customer traffic to our stores. Sunoco LP may not be able to compete successfully against current and future competitors, and competitive pressures faced by Sunoco LP could have a material adverse effect on its business, results of operations and cash available for distribution to its unitholders.

Sunoco LP may be subject to adverse publicity resulting from concerns over food quality, product safety, health or other negative events or developments that could cause consumers to avoid its retail locations or independently operated commission agent or dealer locations.

Sunoco LP may be the subject of complaints or litigation arising from food-related illness or product safety which could have a negative impact on its business. Negative publicity, regardless of whether the allegations are valid, concerning food quality, food safety or other health concerns, food service facilities, employee relations or other matters related to its operations may materially adversely affect demand for its food and other products and could result in a decrease in customer traffic to its retail stores or independently operated commission agent or dealer locations.

It is critical to Sunoco LP's reputation that they maintain a consistent level of high quality at their food service facilities and other franchise or fast food offerings. Health concerns, poor food quality or operating issues stemming from one store or a limited number of stores could materially and adversely affect the operating results of some or all of their stores and harm the company-owned brands, continuing favorable reputation, market value and name recognition.

Sunoco LP does not own all of the land on which its retail service stations are located, and Sunoco LP leases certain facilities and equipment, and Sunoco LP is subject to the possibility of increased costs to retain necessary land use which could disrupt its operations.

Sunoco LP does not own all of the land on which its retail service stations are located. Sunoco LP has rental agreements for approximately 36% of the company, commission agent or dealer operated retail service stations where Sunoco LP currently controls the real estate. Sunoco LP also has rental agreements for certain logistics facilities. As such, Sunoco LP is subject to the possibility of increased costs under rental agreements with landowners, primarily through rental increases and renewals of expired agreements. Sunoco LP is also subject to the risk that such agreements may not be renewed. Additionally, certain facilities and equipment (or parts thereof) used by Sunoco LP are leased from third parties for specific periods. Sunoco LP's inability to renew leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material adverse effect on its financial condition, results of operations and cash flows.

Sunoco LP is subject to federal laws related to the Renewable Fuel Standard.

New laws, new interpretations of existing laws, increased governmental enforcement of existing laws or other developments could require us to make additional capital expenditures or incur additional liabilities. For example, certain independent refiners have initiated discussions with the EPA to change the way the Renewable Fuel Standard ("RFS") is administered in an attempt to shift the burden of compliance from refiners and importers to blenders and distributors. Under the RFS, which requires an annually increasing amount of biofuels to be blended into the fuels used by U.S. drivers, refiners/importers are obligated to obtain renewable identification numbers ("RINs") either by blending biofuel into gasoline or through purchase in the open market. If the obligation was shifted from the importer/refiner to the blender/distributor, the Partnership would potentially have to utilize the RINs it obtains through its blending activities to satisfy a new obligation and would be unable to sell RINs to other obligated parties, which may cause an impact on the fuel margins associated with Sunoco LP's sale of gasoline. In addition, the RFS regulations are highly complex and evolving, and the RINs market is subject to significant price volatility as a result. The price of RINs to meet compliance obligations under the RFS could be substantial and adversely impact our financial condition.

The occurrence of any of the events described above could have a material adverse effect on Sunoco LP's business, financial condition, results of operations and cash available for distribution to its unitholders.

Sunoco LP is subject to federal, state and local laws and regulations that govern the product quality specifications of refined petroleum products it purchases, stores, transports, and sells to its distribution customers.

Various federal, state, and local government agencies have the authority to prescribe specific product quality specifications for certain commodities, including commodities that Sunoco LP distributes. Changes in product quality specifications, such as reduced sulfur content in refined petroleum products, or other more stringent requirements for fuels, could reduce Sunoco LP's ability to procure product, require it to incur additional handling costs and/or require the expenditure of capital. If Sunoco LP is unable to procure product or recover these costs through increased selling price, it may not be able to meet its financial obligations. Failure to comply with these regulations could result in substantial penalties for Sunoco LP.

USAC's customers may choose to vertically integrate their operations by purchasing and operating their own compression fleet, increasing the number of compression units they currently own or using alternative technologies for enhancing crude oil production.

USAC's customers that are significant producers, processors, gatherers and transporters of natural gas and crude oil may choose to vertically integrate their operations by purchasing and operating their own compression fleets in lieu of using USAC's compression services. The historical availability of attractive financing terms from financial institutions and equipment manufacturers facilitates this possibility by making the purchase of individual compression units increasingly affordable to USAC's customers. In addition, there are many technologies available for the artificial enhancement of crude oil production, and USAC's customers may elect to use these alternative technologies instead of the gas lift compression services USAC provides. Such vertical integration, increases in vertical integration or use of alternative technologies could result in decreased demand for USAC's compression services, which may have a material adverse effect on its business, results of operations, financial condition and reduce its cash available for distribution.

A significant portion of USAC's services are provided to customers on a month-to-month basis, and USAC cannot be sure that such customers will continue to utilize its services.

USAC's contracts typically have an initial term of between six months and five years, depending on the application and location of the compression unit. After the expiration of the initial term, the contract continues on a month-to-month or longer basis until terminated by USAC or USAC's customers upon notice as provided for in the applicable contract. For the year ended December 31, 2020, approximately 33% of USAC's compression services on a revenue basis were provided on a month-to-month basis to customers who continue to utilize its services following expiration of the primary term of their contracts. These customers can generally terminate their month-to-month compression services contracts on 30-days' written notice. If a significant number of these customers were to terminate their month-to-month services, or attempt to renegotiate their month-to-month contracts at substantially lower rates, it could have a material adverse effect on USAC's business, results of operations, financial condition and cash available for distribution.

USAC's preferred units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of its common units.

USAC's preferred units rank senior to all of its other classes or series of equity securities with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for its common units or could make it more difficult for USAC to sell its common units in the future.

In addition, distributions on USAC's preferred units accrue and are cumulative, at the rate of 9.75% per annum on the original issue price, which amounts to a quarterly distribution of $24.375 per preferred unit. If USAC does not pay the required distributions on its preferred units, USAC will be unable to pay distributions on its common units. Additionally, because distributions on USAC's preferred units are cumulative, USAC will have to pay all unpaid accumulated distributions on the preferred units before USAC can pay any distributions on its common units. Also, because distributions on USAC's common units are not cumulative, if USAC does not pay distributions on its common units with respect to any quarter, USAC's common unitholders will not be entitled to receive distributions covering any prior periods if USAC later recommences paying distributions on its common units.

USAC's preferred units are convertible into common units by the holders of USAC's preferred units or by USAC in certain circumstances. USAC's obligation to pay distributions on USAC's preferred units, or on the common units issued following the conversion of USAC's preferred units, could impact USAC's liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general Partnership purposes. USAC's obligations to the holders of USAC's preferred units could also limit its ability to obtain additional financing or increase its borrowing costs, which could have an adverse effect on its financial condition.

Risks Related to Conflicts of Interest

The fiduciary duties of our general partner's officers and directors may conflict with those of Sunoco LP's or USAC's respective general partners.

Conflicts of interest may arise because of the relationships among Sunoco LP, USAC, their general partners and us. Our General Partner's directors and officers have fiduciary duties to manage our business in a manner beneficial to us and our Unitholders. Some of our general partner's directors or officers are also directors and/or officers of Sunoco LP's general partner or USAC's general partner, and have fiduciary duties to manage the respective businesses of Sunoco LP and USAC in a manner beneficial to Sunoco LP, USAC and their respective unitholders. The resolution of these conflicts may not always be in our best interest or that of our Unitholders.

Although we control Sunoco LP and USAC through our ownership of Sunoco LP's and USAC's general partners, Sunoco LP's and USAC's general partners owe duties to Sunoco LP and Sunoco LP's unitholders and USAC and USAC's unitholders, respectively, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and Sunoco LP and USAC and their respective limited partners, on the other hand. The directors and officers of Sunoco LP's and USAC's general partners have duties to manage Sunoco LP and USAC, respectively, in a manner beneficial to us. At the same time, the general partners have fiduciary duties to manage Sunoco LP and USAC in a manner beneficial to Sunoco LP and USAC and their respective limited partners. The boards of directors of Sunoco LP's and USAC's general partner will resolve any such conflict and have broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with Sunoco LP and USAC may arise in the following situations:

- the allocation of shared overhead expenses to Sunoco LP, USAC and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and Sunoco LP and USAC, on the other hand;
- the determination of the amount of cash to be distributed to Sunoco LP's and USAC's partners and the amount of cash to be reserved for the future conduct of Sunoco LP's and USAC's businesses;
- the determination whether to make borrowings under Sunoco LP's and USAC's revolving credit facilities to pay distributions to their respective partners;
- the determination of whether a business opportunity (such as a commercial development opportunity or an acquisition) that we may become aware of independently of Sunoco LP and USAC is made available for Sunoco LP and USAC to pursue; and
- any decision we make in the future to engage in business activities independent of Sunoco LP and USAC.

Potential conflicts of interest may arise among our general partner, its affiliates and us. Our general partner and its affiliates have limited fiduciary duties to us, which may permit them to favor their own interests to the detriment of us.

Conflicts of interest may arise among our general partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following:

- our general partner is allowed to take into account the interests of parties other than us, including Sunoco LP and USAC, and their respective affiliates and any general partners and limited partnerships acquired in the future, in resolving conflicts of interest, which has the effect of limiting its fiduciary duties to us.
- our general partner has limited its liability and reduced its fiduciary duties under the terms of our partnership agreement, while also restricting the remedies available for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, Unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.

- our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution.
- our general partner determines which costs it and its affiliates have incurred are reimbursable by us.
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us.
- our general partner controls the enforcement of obligations owed to us by it and its affiliates.
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits our general partner's fiduciary duties to us and restricts the remedies available for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our general partner is entitled to make other decisions in "good faith" if it reasonably believes that the decisions are in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by a conflicts committee of the board of directors of our general partner and not involving a vote of Unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us;
- provides that unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty;
- provides that our general partner may resolve any conflicts of interest involving us and our general partner and its affiliates, and any resolution of a conflict of interest by our general partner that is "fair and reasonable" to us will be deemed approved by all partners, including the Unitholders, and will not constitute a breach of the partnership agreement;
- provides that our general partner may, but is not required, in connection with its resolution of a conflict of interest, to seek "special approval" of such resolution by appointing a conflicts committee of the general partner's board of directors composed of two or more independent directors to consider such conflicts of interest and to recommend action to the board of directors, and any resolution of the conflict of interest by the conflicts committee shall be conclusively deemed "fair and reasonable" to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our Unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to Unitholders.

Although we control Sunoco LP and USAC through our ownership of Sunoco LP's and USAC's general partners, Sunoco LP's and USAC's general partners owe duties to Sunoco LP and Sunoco LP's unitholders and USAC and USAC's unitholders, respectively, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and Sunoco LP and USAC and their respective limited partners, on the other hand. The directors and officers of Sunoco

LP's and USAC's general partners have duties to manage Sunoco LP and USAC, respectively, in a manner beneficial to us. At the same time, the general partners have fiduciary duties to manage Sunoco LP and USAC in a manner beneficial to Sunoco LP and USAC and their respective limited partners. The boards of directors of Sunoco LP's and USAC's general partner will resolve any such conflict and have broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with Sunoco LP and USAC may arise in the following situations:

- the allocation of shared overhead expenses to Sunoco LP, USAC and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and Sunoco LP and USAC, on the other hand;
- the determination of the amount of cash to be distributed to Sunoco LP's and USAC's partners and the amount of cash to be reserved for the future conduct of Sunoco LP's and USAC's businesses;
- the determination whether to make borrowings under Sunoco LP's and USAC's revolving credit facilities to pay distributions to their respective partners;
- the determination of whether a business opportunity (such as a commercial development opportunity or an acquisition) that we may become aware of independently of Sunoco LP and USAC is made available for Sunoco LP and USAC to pursue; and
- any decision we make in the future to engage in business activities independent of Sunoco LP and USAC.

Affiliates of our general partner may compete with us.

Except as provided in our partnership agreement, affiliates and related parties of our general partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

Tax Risks to Unitholders

Our tax treatment depends on our continuing status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation. If the IRS were to treat us and our subsidiaries, including Sunoco LP and USAC as a corporation for federal income tax purposes or if we, Sunoco LP or USAC become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this matter. The value of our investments in Sunoco LP and USAC, depend largely on Sunoco LP and USAC being treated as partnerships for federal income tax purposes. Despite the fact that we, Sunoco LP and USAC are each a limited partnership under Delaware law, we would each be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations and current Treasury Regulations, we believe we, Sunoco LP and USAC satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us, Sunoco LP or USAC to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we, Sunoco LP or USAC were treated as a corporation for federal income tax purposes, we would pay federal income tax at the corporate tax rate and we would likely pay additional state income taxes at varying rates. Distributions to Unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to Unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to Unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of our units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. We currently own property or conduct business in many states that impose a margin or franchise tax. In the future, we may expand our operations. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our Unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state, local or foreign income tax purposes, the target distribution amounts may be adjusted to reflect the impact of that law or interpretation on us.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present United States federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. Members of Congress have frequently proposed and considered substantive changes to the existing United States federal income tax laws that affect publicly traded partnerships, including proposals that would eliminate our ability to qualify for partnership tax treatment. Recent proposals have provided for the expansion of the qualifying income exception for publicly traded partnerships in certain circumstances and other proposal have provided for the total elimination of the qualifying income exception upon which we rely for our partnership tax treatment.

Any modification to the United States federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for United States federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our units.

If the IRS contests the federal income tax positions we take, the market for our units may be adversely affected and the costs of any such contest will reduce cash available to pay our debt securities and for distributions to our Unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our units, and the prices at which they trade. In addition, the costs of any contest between us and the IRS will result in a reduction in our cash available to pay our debt securities and for distribution to our Unitholders and thus will be borne indirectly by our Unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available to pay our debt securities and for distribution to our Unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue an information statement to each Unitholder and former Unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our Unitholders and former Unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current Unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such Unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our Unitholders might be substantially reduced.

Unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our Unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. Our Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on disposition of our units could be more or less than expected.

If a Unitholder sells their units, the Unitholder will recognize a gain or loss equal to the difference between the amount realized and that Unitholder's tax basis in those units. Because distributions in excess of a Unitholder's allocable share of our net taxable income decrease such Unitholder's tax basis in their units, the amount, if any, of such prior excess distributions with respect to the units a Unitholder sells will, in effect, become taxable income to a Unitholder if such units are sold at a price greater than their tax basis in those units, even if the price such Unitholder receives is less than their original costs. In addition, because the amount realized includes a Unitholder's share of our nonrecourse liabilities, if a Unitholder sells their units, a Unitholder may incur a tax liability in excess of the amount of cash received from the sale.

A substantial portion of the amount realized from a Unitholder's sale of their units, whether or not representing gain, may be taxed as ordinary income to such Unitholder due to potential recapture items, including depreciation recapture. Thus, a Unitholder may recognize both ordinary income and capital loss from the sale of Common Units if the amount realized on a sale of such units is less than such Unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a Unitholder sells their units, such Unitholder may recognize ordinary income from our allocations of income and gain to such Unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Tax-exempt entities face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from United States federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our units.

Non-United States Unitholders will be subject to United States taxes and withholding with respect to their income and gain from owning our units.

Non-United States Unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a United States trade or business ("effectively connected income"). Income allocated to our Unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a United States trade or business. As a result, distributions to a non-United States Unitholder will be subject to withholding at the highest applicable effective tax rate and a non-United States Unitholder who sells or otherwise disposes of a unit will also be subject to United States federal income tax on the gain realized from the sale or disposition of that unit.

Moreover, the transferee of an interest in a partnership that is engaged in a United States trade or business is generally required to withhold 10% of the "amount realized" by the transferor unless the transferor certifies that it is not a foreign person. While the determination of a partner's "amount realized" generally includes any decrease of a partner's share of the partnership's liabilities, the Treasury regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership, such as our units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner's share of a publicly traded partnership's liabilities. The Treasury regulations and other guidance from the IRS provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2023. Thereafter, the obligation to withhold on a transfer of interests in a publicly traded partnership that is effected through a broker is imposed on the transferor's broker. Current and prospective non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our units.

We have subsidiaries that will be treated as corporations for federal income tax purposes and subject to corporate-level income taxes.

Even though we (as a partnership for United States federal income tax purposes) are not subject to United States federal income tax, some of our operations are conducted through subsidiaries that are organized as corporations for United States federal income tax purposes. The taxable income, if any, of subsidiaries that are treated as corporations for United States federal income tax purposes, is subject to corporate-level United States federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our Unitholders. If the IRS or other state or local jurisdictions were to successfully assert that these corporations have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filings positions taken by these corporate subsidiaries require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by these subsidiaries are fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

We treat each purchaser of units as having the same tax benefits without regard to the actual units purchased. The IRS may challenge this treatment, which could result in a Unitholder owing more tax and may adversely affect the value of the units.

Because we cannot match transferors and transferees of units and because of other reasons, we have adopted certain methods for allocating depreciation, depletion and amortization that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to our Unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of units and could have a negative impact on the value of our units or result in audit adjustments to tax returns of our Unitholders. Moreover, because we have subsidiaries that are organized as C corporations for federal income tax purposes, a successful IRS challenge could result in these subsidiaries having a greater tax liability than we anticipate and, therefore, reduce the cash available for distribution to our partnership and, in turn, to our Unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge aspects of our proration method, and if successful, we would be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets and (iii) in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

A Unitholder whose common or preferred units are the subject of a securities loan (e.g. a loan to a short seller to cover a short sale of common or preferred units) may be considered as having disposed of those units. If so, such Unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a Unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the Unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller, and the Unitholder and may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining Unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our Common Units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of our Unitholders and our general partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our Common Units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain Unitholders and our general partner, which may be unfavorable to such Unitholders. Moreover, under our current valuation methods, subsequent purchasers of our Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our Unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our Unitholders. It also could affect the amount of gain on the sale of Common Units by our Unitholders and could have a negative impact on the value of our Common Units or result in audit adjustments to the tax returns of our Unitholders without the benefit of additional deductions.

Unitholders will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where they do not live as a result of investing in our units.

In addition to United States federal income taxes, the Unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we or our subsidiaries conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each Unitholder to file all federal, state and local tax returns.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our Unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is generally limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Treatment of distributions on Energy Transfer Preferred Units as guaranteed payments for the use of capital is uncertain and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

The tax treatment of distributions on our Preferred Units is uncertain. We will treat Preferred Unitholders as partners for tax purposes and will treat distributions on the Preferred Units as guaranteed payments for the use of capital that will generally be taxable to Preferred Unitholders as ordinary income. Preferred Unitholders will recognize taxable income from the accrual of such a guaranteed payment (even in the absence of a contemporaneous cash distribution). Otherwise, except in the case of our liquidation, Preferred Unitholders are generally not anticipated to share in our items of income, gain, loss or deduction, nor will we allocate any share of our nonrecourse liabilities to Preferred Unitholders. If the Energy Transfer Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to Preferred Unitholders.

Although we expect that much of the income we earn will be eligible for the 20% deduction for qualified publicly traded partnership income, recently issued final Treasury Regulations provide that income attributable to a guaranteed payment for the use of capital is not eligible for the 20% deduction for qualified business income. As a result income attributable to a guaranteed payment for use of capital recognized by holders of our Preferred Units is not eligible for the 20% deduction for qualified business income.

A Preferred Unitholder will be required to recognize gain or loss on a sale of Energy Transfer Preferred Units equal to the difference between the amount realized by such Preferred Unitholder and such Preferred Unitholder's tax basis in the Energy Transfer Preferred Units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such Preferred Unitholder receives in exchange for such Energy Transfer Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the Preferred Unitholder to acquire such Energy Transfer Preferred Units. Gain or loss recognized by a Preferred Unitholder on the sale or exchange of Energy Transfer Preferred Units held for more than one year generally will be taxable as long-term capital gain or loss. Because Preferred Unitholders will generally not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such Preferred Unitholders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in our Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-United States persons raises issues unique to them. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for federal income tax purposes. Distributions to non-United States Preferred Unitholders will be subject to withholding taxes. If the amount of withholding exceeds the amount of United States federal income tax actually due, non-United States Preferred Unitholders may be required to file United States federal income tax returns in order to seek a refund of such excess.

All Preferred Unitholders are urged to consult a tax advisor with respect to the consequences of owning Energy Transfer Preferred Units.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in "Item 1. Business." In addition, we own office buildings for our executive offices in Dallas, Texas and office buildings in Newton Square, Pennsylvania; Houston, Texas and San Antonio, Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

We believe that we have satisfactory title to or valid rights to use all of our material properties. Although some of our properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-competition agreements and immaterial encumbrances, easements and restrictions, we do not believe that any such burdens will materially interfere with our continued use of such properties in our business, taken as a whole. In addition, we believe that we have, or are in the process of obtaining, all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local government and regulatory authorities which relate to ownership of our properties or the operations of our business.

Substantially all of our pipelines, which are described in "Item 1. Business," are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, properties on which our pipelines were built were purchased in fee. We also own and operate multiple natural gas and NGL storage facilities and own or lease other processing, treating and conditioning facilities in connection with our midstream operations.

ITEM 3. LEGAL PROCEEDINGS

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 December 31, 2021, Sunoco Defendants are defendants in five cases, including one case each initiated by the States of Maryland and Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants ETO, ETP Holdco, and Sunoco Partners Marketing and Terminals L.P.

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.

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. On January 25, 2022, the chief judge assigned an administrative law judge and set a timeline for a prehearing conference. 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. Energy Transfer and Rover intend to vigorously defend this claim.

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. Enforcement Staff has provided Rover with a notice pursuant to Section 1b.19 of the Commission's regulations that Enforcement Staff intends to recommend that the Commission pursue an enforcement action against Rover and the Partnership. The company disagrees with Enforcement Staff's findings and intends to vigorously defend against any potential penalty. On December 16, 2021, FERC issued an Order to Show Cause and Notice of Proposed Penalty (Docket No. IN17-4-000), ordering Rover to show cause why it 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 filed an answer responding to this Order on December 22, 2021. 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, and the non-public nature of the investigation, 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.

In February 2017, we received letters from the DOJ on behalf of EPA and Louisiana Department of Environmental Quality ("LDEQ") notifying SPLP and Mid-Valley Pipeline Company ("Mid-Valley") that enforcement actions were being pursued for three separate crude oil releases: (a) an estimated 550 barrels released from the Colmesneil-to-Chester pipeline in Tyler County, Texas ("Colmesneil") which allegedly occurred in February 2013; (b) an estimated 4,509 barrels released from the Longview-to-Mayersville pipeline in Caddo Parish, Louisiana (a/k/a Milepost 51.5) which allegedly occurred in October 2014; and (c) an estimated 40 barrels released from the Wakita 4-inch gathering line in Oklahoma which allegedly occurred in January 2015. In January 2019, a Consent Decree approved by all parties as well as an accompanying complaint was filed in the United States District Court for the Western District of Louisiana seeking public comment and final court approval to resolve all penalties with the DOJ and LDEQ for the three releases. Subsequently, the court approved the Consent Decree and the penalty payment of $5.4 million was satisfied. The Consent Decree requires certain injunctive relief to be completed on the Longview-to-Mayersville pipeline within three years but the injunctive relief is not expected to have any material impact on operations. In addition to resolution of the civil penalty and injunctive relief, we continue to discuss natural resource damages with the Louisiana trustees related to the Caddo Parish, Louisiana release. In addition to resolution of the civil penalty and injunctive relief, we settled natural resource damages with the Louisiana trustees related to the Caddo Parish, Louisiana release for approximately $1.2 million in November and the matter is now closed.

On November 3, 2017, the State of Ohio and the Ohio Environmental Protection Agency ("Ohio EPA") filed suit against Rover and other defendants (collectively, the "Defendants") seeking to recover approximately $2.6 million in civil penalties allegedly owed and certain injunctive relief related to permit compliance. The Defendants filed several motions to dismiss, which were granted on all counts. The Ohio EPA appealed, and on December 9, 2019, the Fifth District court of appeals entered a unanimous judgment affirming the trial court. The Ohio EPA sought review from the Ohio Supreme Court. On April 22, 2020, the Ohio Supreme Court granted the review. Briefing has concluded and oral arguments were held on January 26, 2021, but no opinion has yet been issued.

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

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

In January 2019, we received notice from the DOJ on behalf of the EPA that a civil penalty enforcement action was being pursued under the Clean Water Act for an estimated 450 barrel crude oil release from the Mid-Valley Pipeline operated by SPLP and owned by Mid-Valley Pipeline Corporation. The release purportedly occurred in October 2014 on a nature preserve located in Hamilton County, Ohio, near Cincinnati, Ohio. After discovery and notification of the release, SPLP conducted substantial emergency response, remedial work and primary restoration in three phases and the primary restoration has been acknowledged to be complete. Operation and maintenance (O&M) activities will continue for several years. In December of 2019, SPLP reached an agreement in principal with the EPA regarding payment of a civil penalty which will be subject to public comment. The DOJ, on behalf of United States Department of Interior Fish and Wildlife, and the Ohio Attorney General, on behalf of the Ohio EPA, along with technical representatives from those agencies have been discussing natural resource damage assessment claims related to state endangered species and compensatory restoration. The timing and outcome of these matters cannot be reasonably determined at this time; however, we do not expect there to be a material impact to our results of operations, cash flows or financial position.

After an inadvertent return ("IR") occurred on August 10, 2020 in Chester County, Pennsylvania that resulted in a discharge to Marsh Creek State Park, on September 11, 2020, the PADEP issued an Administrative Order that ordered SPLP to cease all construction at the location, grout the borehole, and perform a 1.01-mile reroute of the 20-inch pipeline in the area. SPLP filed a Notice of Appeal with the Pennsylvania Environmental Hearing Board ("EHB") on September 25, 2020, and subsequently filed a Petition for Supersedeas on October 8, 2020. On December 16, 2020, the EHB partially granted SPLP's Petition for Supersedeas, suspending the requirements of the Administrative Order to re-route the 20-inch pipeline and grout the HDD borehole. Following the decision, SPLP negotiated with PADEP to change the method of installation for the 20-inch pipeline from HDD to an open cut along an alternative route near to the original right-of-way. SPLP submitted a major permit modification to PADEP on October 7, 2021, to reflect the change in construction method and location. On December 6, 2021, a settlement was reached that resolved the EHB appeal through a Consent Order & Agreement ("COA"). The COA allowed PADEP to issue the major permit modification so that the 20-inch pipeline installation could be completed. As part of the COA, SPLP paid a $341,000 civil penalty to PADEP, SPLP paid a $4 million settlement to the Department of Conservation and Natural Resources for alleged natural resource damages to Marsh Creek State Park, SPLP agreed to complete the restoration of a wetland and stream in the area, and SPLP agreed to complete a restoration and dredging project in a portion of Marsh Creek State Park known as “Ranger Cove.” The 20-inch pipeline has now been fully installed in the area, and restoration of the wetland and streams have been completed. The restoration and dredging project at Ranger Cove is anticipated to take place in 2022.

In July 2021, Energy Transfer LP, Energy Transfer R&M and certain of their affiliates were named as parties in a complaint filed by the Ohio Petroleum Underground Storage Tank Release Compensation Board (“PUSTRCB”) to recover over $8.5 million paid by PUSTRCB to Energy Transfer R&M or on Energy Transfer R&M’s behalf due to alleged false, misleading and/or fraudulent representations. Specifically, in 1996, Energy Transfer R&M filed a lawsuit in the Superior Court of California (Los Angeles City) against its historic Commercial General Liability (“CGL”) insurers, excess and re-insurers entitled Jalisco et al. v. Argonaut et al. (“Jalisco”) - Case No. BC158441 - seeking a declaration of coverage under insurance policies which had been in place before 1986. The Jalisco action included refineries, Superfund sites, oil fields, pipelines, and service stations, among other sites, and the lawsuit was ultimately settled with the insurers. Sunoco, Inc. received reimbursement from PUSTRCB for costs incurred at service stations located in Ohio, and PUSTRCB now claims that Sunoco, Inc. failed to disclose to PUSTRCB the claims asserted against its insurers, the Jalisco action and the settlements and failed to repay the monies received from PUSTRCB. PUSTRCB seeks compensatory damages, restitution and disgorgement, punitive damages, interest and attorney’s fees. ET cannot predict the outcome of this lawsuit but firmly believes that the claims are without merit and intends to vigorously defend against them.

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 above were decided against us, it would not be material to our financial position, results of operations or cash flows, we are required to report environmental governmental proceedings if we reasonably believe that such proceedings will result in monetary sanctions in excess of $300,000.

For a description of other legal proceedings, see Note 11 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data.”

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Description of Units

As of February 15, 2022, there were approximately 12,805 holders of record of our common units, which number does not separately account for individual participants in securities positions listings. Common units represent limited partner interests in us that entitle the holders to the rights and privileges specified in Energy Transfer's Third Amended and Restated Agreement of Limited Partnership, as amended to date (the "Partnership Agreement").

As of December 31, 2021, limited partners own an aggregate 99.9% limited partner interest in us. Our General Partner owns an aggregate 0.1% general partner interest in us. Our common units are registered under the Exchange Act, and are listed for trading on the NYSE under the ticker symbol "ET." Each holder of a common unit is entitled to one vote per unit on all matters presented to the limited partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all common units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our Partnership Agreement. The common units are entitled to distributions of Available Cash as described below under "Cash Distribution Policy."

Energy Transfer Class A Units

As of February 11, 2022, the Partnership had outstanding 763,021,449 Class A units ("Energy Transfer Class A Units") representing limited partner interests in the Partnership to the General Partner. The Energy Transfer Class A Units are entitled to vote together with the Partnership's common units, as a single class, except as required by law. Additionally, Energy Transfer's partnership agreement provides that, under certain circumstances, upon the issuance by the Partnership of additional common units or any securities that have voting rights that are pari passu with the Partnership common units, the Partnership will issue to any holder of Energy Transfer Class A Units additional Energy Transfer Class A Units such that the holder maintains a voting interest in the Partnership that is identical to its voting interest in the Partnership prior to such issuance of common units. In connection with the Enable Acquisition, we issued an additional 92,730,532 Energy Transfer Class A Units in December 2021. The Energy Transfer Class A Units are not entitled to distributions and otherwise have no economic attributes.

Energy Transfer Preferred Units

The Partnership currently has the following series of preferred units outstanding:

Series of Preferred Units	Units Issued and Outstanding	Liquidation Preference per Unit	Date Issued[1]
6.250% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	950,000	$ 1,000	April 2021
6.625% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	550,000	1,000	April 2021
7.375% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	18,000,000	25	April 2021
7.625% Series D Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	17,800,000	25	April 2021
7.600% Series E Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	32,000,000	25	April 2021
6.750% Series F Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units	500,000	1,000	April 2021
7.125% Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units	1,484,780	1,000	April 2021 and December 2021[2]
6.500% Series H Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units	900,000	1,000	June 2021

(1) In connection with the Rollup Mergers on April 1, 2021, as discussed in Note 1 to our consolidated financial statements in "Item 8. Financial Statements and Supplementary Data", all of ETO's previously outstanding preferred units were converted to Energy Transfer Preferred Units with identical distribution and redemption rights.

(2) In connection with the Enable Acquisition in December 2021, Energy Transfer issued 384,780 additional Series G Preferred Units. The total reflected above includes these additional Series G Preferred Units, as well as the 1,100,000 Series G Preferred Units originally issued in the Rollup Mergers.

Additional information for each series of outstanding preferred units, including information on distributions and redemption, is available in Note 8 in the notes to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

Cash Distribution Policy

General. Energy Transfer will distribute all of its “Available Cash” to its Unitholders and its General Partner within 50 days following the end of each fiscal quarter.

Definition of Available Cash. Available Cash is defined in the Partnership Agreement and generally means, with respect to any calendar 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 the General Partner to:

- provide for the proper conduct of its business;
- comply with applicable law and/or debt instrument or other agreement; and
- provide funds for distributions to Unitholders and its General Partner in respect of any one or more of the next four quarters.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

The following table discloses purchases of Energy Transfer Common Units made by us or on our behalf in the quarter ended December 31, 2021:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Units That May Yet be Purchased Under the Plans or Programs
October 2021	—	$ —	—	$ —
November 2021	—	—	—	—
December 2021	4,200,000	7.4492	4,200,000	879,544,663

Securities Authorized for Issuance Under Equity Compensation Plans

For information on the securities authorized for issuance under Energy Transfer’s equity compensation plans, see “Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.”

ITEM 6. [RESERVED]

This item is reserved as a result of the Company’s adoption of Item 301 of Regulation S-K, pursuant to rules adopted by the SEC on November 19, 2020, which included removing the requirement to include selected financial data.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

Energy Transfer LP is a Delaware limited partnership whose common units are publicly traded on the NYSE under the ticker symbol “ET.”

The following discussion of our historical consolidated financial condition and results of operations should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included in “Item 8. Financial Statements and Supplementary Data” of this report. 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 “Item 1A. Risk Factors” of this report.

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

OVERVIEW

Energy Transfer directly and indirectly owns equity interests in Sunoco LP and USAC, which are limited partnerships engaged in diversified energy-related services. Sunoco LP and USAC have publicly traded common units.

Energy Transfer derives cash flows from distributions related to its investment in its subsidiaries, including Sunoco LP and USAC. The amount of cash that Sunoco LP and USAC distribute to their respective partners, including Energy Transfer, each quarter is based on earnings from their respective business activities and the amount of available cash, as discussed below.

The primary activities in which we are engaged, which are in the United States and Canada, and the operating subsidiaries through which we conduct those activities are as follows:

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

In addition, we own investments in other businesses, including Sunoco LP and USAC, both of which are publicly traded master limited partnerships.

Energy Transfer derives cash flows from distributions related to its investment in its subsidiaries, including Sunoco LP and USAC. Energy Transfer’s primary cash requirements are for distributions to its partners, general and administrative expenses and debt service requirements. Energy Transfer distributes its available cash remaining after satisfaction of the aforementioned cash requirements to its Unitholders on a quarterly basis.

We expect our subsidiaries to utilize their resources, along with cash from their operations, to fund their announced growth capital expenditures and working capital needs; however, Energy Transfer may issue debt or equity securities from time to time as we deem prudent to provide liquidity for new capital projects of our subsidiaries or for other partnership purposes.

General

Our primary objective is to increase the level of our distributable cash flow to our Unitholders over time by pursuing a business strategy that is currently focused on growing our subsidiaries’ natural gas and liquids businesses through, among other things, pursuing certain construction and expansion opportunities relating to our subsidiaries’ existing infrastructure and acquiring certain strategic operations and businesses or assets. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash our subsidiaries generate from their operations.

Our reportable segments 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.

Recent Developments

Energy Transfer and ETO Rollup Mergers

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

- All of ETO's long-term debt was assumed by Energy Transfer, as more fully described in Note 6 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data.".
- Each issued and outstanding ETO preferred unit was converted into the right to receive one newly created Energy Transfer preferred unit. A description of the Energy Transfer Preferred Units is included in Note 8 to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data."
- Each of ETO's issued and outstanding Class K, Class L, Class M and Class N units were converted into an aggregate 675,625,000 newly created Class B Units representing limited partner interests in Energy Transfer. All of the Class B Units are held by ETP Holdco, a wholly-owned subsidiary of Energy Transfer.

Series H Preferred Units Issuance

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

Winter Storm Impacts

Winter Storm Uri, which occurred in February 2021, resulted in one-time impacts to the Partnership's consolidated net income and Adjusted EBITDA and also affected the results of operations in certain segments, as discussed in "Results of Operations". The recognition of the impacts of Winter Storm Uri during the year ended December 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.

Enable Acquisition

On December 2, 2021, the Partnership completed the previously announced merger with Enable (the "Enable Acquisition"). Under the terms of the merger agreement, Enable's common unitholders received 0.8595 of an Energy Transfer common unit in exchange for each Enable common unit. In addition, each outstanding Enable Series A preferred unit was exchanged for 0.0265 of an Energy Transfer Series G Preferred Unit. A total of 384,780 Series G Preferred Units were issued in connection with the Enable Acquisition. The total fair value of Energy Transfer common units and Series G Preferred Units issued was approximately $3.5 billion at the closing date. Energy Transfer also made a $10 million cash payment for Enable's general partner.

In connection with the Enable Acquisition on December 2, 2021, Energy Transfer repaid $800 million outstanding on the Enable 2019 Term Loan Agreement and $35 million outstanding on the Enable Five-Year Revolving Credit Facility, and both facilities were terminated. In addition, the Partnership assumed $3.18 billion aggregate principal amount of Enable senior notes.

Regulatory Update

Interstate Natural Gas Transportation Regulation

Rate Regulation

Effective January 2018, the 2017 Tax Cuts and Jobs Act (the "Tax Act") changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related proposals, the FERC addressed treatment of federal income tax allowances in regulated entity rates. The FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating that it will no longer permit master limited partnerships to recover an income tax allowance in their cost-of-service rates. The FERC issued the Revised Policy Statement in response to a remand from the United States Court of Appeals for the District of Columbia Circuit in United Airlines v. FERC, in which the court determined that the FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not "double recover" its taxes under the current policy by both including an income-tax allowance in its cost of service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, the FERC clarified that a pipeline organized as a master limited partnership will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs. On July 31, 2020, the United States Court of Appeals for the District of Columbia Circuit issued an opinion upholding the FERC's decision denying a separate master limited partnership recovery of an income tax allowance and its decision not to require the master limited partnership to refund accumulated deferred income tax balances. In light of the rehearing order's clarification regarding an individual entity's ability to argue in support of recovery of an income tax allowance and the court's subsequent opinion upholding denial of an income tax allowance to a master limited partnership, the impact of the FERC's policy on the treatment of income taxes on the rates we can charge for FERC-regulated transportation services is unknown at this time.

Even without application of the FERC's 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 the 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. The FERC has not taken any further action regarding the 2018 NOI, 2021 NOI, or Technical Conference on Greenhouse Gas Mitigation, and we are unable to predict what, if any, changes may be proposed as a result of the NOIs or following the technical conference that might affect our natural gas pipeline or LNG facility operations, or when such proposals, if any, might become effective. We do not expect that any change in this policy would affect us in a materially different manner than any other natural gas pipeline company operating in the United States.

Interstate Common Carrier Regulation

The FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods, or PPI-FG. Many existing pipelines utilize the FERC liquids index to change transportation rates annually. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. The FERC's indexing methodology is subject to review every five years. In a December 2020 order, FERC determined that during the five-year period commencing July 1, 2021 and ending June 30, 2026, common carriers charging indexed rates will be permitted to adjust their indexed ceilings annually by PPI-FG plus 0.78 percent. The Commission 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. 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.

Trends and Outlook

Recent market disruptions involving the COVID-19 pandemic have negatively impacted our earnings and cash flows from operations and may continue to do so. Demand for natural gas, NGLs, refined products and/or crude oil caused by the COVID-19 pandemic has generally trended toward a recovery since the lows experienced from the COVID-19 pandemic during 2020. However, recent variants of COVID-19 have continued to cause market disruptions and earnings volatility in 2021. Any future variants or resurgence of existing variants could result in decreased volumes transported on our pipeline systems and decreased overall utilization of our midstream services.

With respect to commodity prices, the outlook is mixed and could have a varying impact on our business. Crude oil prices have seen significant recovery recently; however, global supply uncertainty has kept the forward curve in steep backwardation. Additionally, the market continues to be impacted by heightened levels of demand uncertainty as a result of the ongoing COVID-19 pandemic. We cannot predict the future impacts, or the duration of such impacts, resulting from COVID-19.

Natural gas prices have also strengthened over the past year. Uncertainty about winter weather, particularly in Texas, has supported opportunity on our intrastate transportation and storage assets. In addition, high European natural gas prices have increased demand for LNG exports from the U.S., which has further helped to support prices. The overall outlook for our midstream services will depend, in part, on the timing and extent of recovery in the commodity markets.

While we anticipate that current and projected commodity prices and the related impact to activity levels in both the upstream and midstream sectors will impact our business, we cannot predict the ultimate magnitude of that impact and expect it to be varied across our operations, depending on the region, customer, type of service, contract term and other factors.

While the vast majority of our revenues are from counterparties that are investment grade rated companies, recent market disruptions increased the likelihood that some of our counterparties may be forced to file for bankruptcy protection. However, we believe that the recent increases in commodity prices, along with recent expense-cutting initiatives by many companies, have generally strengthened the credit profile for the majority of our producer counterparties.

Ultimately, the extent to which our business will be impacted by recent market developments depends on the factors described above as well as future developments beyond our control, which are highly uncertain and cannot be predicted. In response to the recent market volatility and uncertainties, we reduced growth capital spending over the last two years, and we expect to continue to a lower level of growth capital spending going forward. See "Liquidity and Capital Resources" below for additional information on our capital expenditures over the last three years and our forecasted capital expenditures for 2022.

Regarding the recently completed Enable acquisition, the transaction closed in December 2021; therefore, our consolidated results for 2021 only reflect one month of activity from Enable's business. We expect that the combined operations will favorably impact our results going forward, primarily impacting our natural gas businesses.

We currently have ample liquidity to fund our business, and we do not anticipate any liquidity concerns in the immediate future (see "Liquidity and Capital Resources" below). In addition, we continue to have access to the debt capital markets on generally favorable terms. In the event we seek additional equity or debt capital, our blended cost of capital for equity and debt is expected to be modestly higher in the near term; however, we will continue to evaluate growth projects and acquisitions as such opportunities may be identified in the future in light of this higher cost of capital.

In addition to the trends and outlook discussed above with respect to the Partnership's existing business and finances, we also anticipate that the Partnership will continue to increase its focus on the development of alternative energy projects. The Partnership has announced several such projects recently and will continue to pursues opportunities aimed at continuing to reduce its environmental footprint throughout its operations.

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. 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.

Year Ended December 31, 2021 Compared to the Year Ended December 31, 2020

Consolidated Results

	Years Ended December 31,		
	2021	2020	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 3,483	$ 863	$ 2,620
Interstate transportation and storage	1,515	1,680	(165)
Midstream	1,868	1,670	198
NGL and refined products transportation and services	2,828	2,802	26
Crude oil transportation and services	2,023	2,258	(235)
Investment in Sunoco LP	754	739	15
Investment in USAC	398	414	(16)
All other	177	105	72
Total Segment Adjusted EBITDA	13,046	10,531	2,515
Depreciation, depletion and amortization	(3,817)	(3,678)	(139)
Interest expense, net of interest capitalized	(2,267)	(2,327)	60
Impairment losses	(21)	(2,880)	2,859
Gains (losses) on interest rate derivatives	61	(203)	264
Non-cash compensation expense	(111)	(121)	10
Unrealized gains (losses) on commodity risk management activities	162	(71)	233
Inventory valuation adjustments	190	(82)	272
Losses on extinguishments of debt	(38)	(75)	37
Adjusted EBITDA related to unconsolidated affiliates	(523)	(628)	105
Equity in earnings of unconsolidated affiliates	246	119	127
Impairment of investments in unconsolidated affiliates	—	(129)	129
Other, net	(57)	(79)	22
Income before income tax expense	6,871	377	6,494
Income tax expense	(184)	(237)	53
Net income	$ 6,687	$ 140	$ 6,547

Adjusted EBITDA (*consolidated*). For the year ended December 31, 2021 compared to the prior year, Adjusted EBITDA increased 24%, primarily due to the impacts of Winter Storm Uri in February 2021. The most significant impacts from the storm were recognized in our intrastate transportation and storage segment, where realized storage margin increased by $1.5 billion compared to the prior period as a result of withdrawals during the storm. In addition, realized natural gas sales increased $950 million and retained fuel revenues increased $132 million in our intrastate transportation and storage segment, and these increases were also primarily due to the impacts of the storm.

The change in Adjusted EBITDA also reflected the impacts of non-storm-related factors among all of the Partnership's reportable segments. In our crude oil transportation and services segment, Segment Adjusted EBITDA decreased $235 million primarily due to lower average tariff rates realized on our Texas crude pipeline system, as well as a decrease from our crude oil acquisition and marketing business. In our interstate transportation and storage segment, Segment Adjusted EBITDA decreased

$165 million primarily due to shipper contract expirations and a recent shipper bankruptcy. In our midstream segment, Segment Adjusted EBITDA increased $198 million primarily due to favorable NGL and natural gas prices.

Additional information on changes impacting Adjusted EBITDA for the year ended December 31, 2021 compared to the prior 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 expense increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

Interest Expense, Net of Interest Capitalized. Interest expense, net of interest capitalized, decreased primarily due to the following:

- interest expense recognized by the Partnership (excluding Sunoco LP and USAC) decreased by $51 million due to lower aggregate debt and lower interest rates on refinanced debt, partially offset by lower capitalized interest;
- an increase of $1 million recognized by USAC was primarily due to increased borrowings under its credit agreement and increased amortization of debt issuance costs related to the amendment and restatement of its credit agreement in the current period, partially offset by lower weighted average interest rates under the credit agreement; and
- a decrease of $12 million recognized by Sunoco LP due to a slight decrease in average total long-term debt and a decrease in the weighted average interest rate on long-term debt for the respective periods.

Impairment Losses. For the year ended December 31, 2021, impairment losses included fixed asset impairments of $5 million recognized by USAC related to its compression equipment and $10 million recognized by Energy Transfer Canada related to a processing plant, as well as a $6 million impairment of intangible assets related to customer contracts within the Partnership's crude operations.

For the year ended December 31, 2020, the Partnership recognized goodwill impairments totaling $2.2 billion and fixed asset impairments totaling $58 million, primarily due to decreases in projected future cash flows as a result of overall market demand decline. In addition, USAC recognized a goodwill impairment of $619 million as well as an equipment impairment of $8 million based on changes in market conditions.

Gains (Losses) on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Gains on interest rate derivatives increased by $264 million during the year ended December 31, 2021, compared to the prior year primarily due to an increase in forward swap rates.

Unrealized Gains (Losses) on Commodity Risk Management Activities. The unrealized gains and losses on our commodity risk management activities include changes in fair value of commodity derivatives and the hedged inventory included in designated fair value hedging relationships. Information on the unrealized gains and losses within each segment are included in "Segment Operating Results" below, and additional information on the commodity-related derivatives, including notional volumes, maturities and fair values, is available in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and in Note 14 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

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. During the year ended December 31, 2021, an increase in fuel prices reduced lower of cost or market reserve requirements for the period by $190 million. During the year ended December 31, 2020, a decline in fuel prices increased lower of cost or market reserve requirements for the period by $82 million, resulting in an adverse impact to net income.

Losses on Extinguishments of Debt. For the year ended December 31, 2021, the losses on extinguishments of debt included amounts related to Sunoco LP's repurchase of its 2026 senior notes in 2021.

For the year ended December 31, 2020, the losses on extinguishments of debt included amounts related to the Senior Note redemption in January 2020. In addition, Sunoco LP recognized a $13 million loss on extinguishment of debt related to the repurchase of its outstanding 2023 senior notes in 2020.

Impairment of Investments in Unconsolidated Affiliate. During the year ended December 31, 2020, the Partnership recorded an impairment to its investment in White Cliffs of $129 million due to a decrease in projected future revenues and cash flows as a result of the overall market demand decline that occurred subsequent to the SemGroup acquisition and related purchase price allocation in December 2019.

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

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

Income Tax Expense. For the year ended December 31, 2021 compared to the same period last year, income tax expense decreased due to recognition of a favorable valuation allowance adjustment for state net operating losses and a state tax rate change in the current period.

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31,		
	2021	2020	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 157	$ 162	$ (5)
FEP [(1)]	—	(139)	139
MEP	(17)	(6)	(11)
White Cliffs	—	20	(20)
Other	106	82	24
Total equity in earnings of unconsolidated affiliates	$ 246	$ 119	$ 127
Adjusted EBITDA related to unconsolidated affiliates[(2)]:			
Citrus	$ 327	$ 347	$ (20)
FEP	—	76	(76)
MEP	18	28	(10)
White Cliffs	19	44	(25)
Other	159	133	26
Total Adjusted EBITDA related to unconsolidated affiliates	$ 523	$ 628	$ (105)
Distributions received from unconsolidated affiliates:			
Citrus	$ 235	$ 191	$ 44
FEP	4	75	(71)
MEP	12	26	(14)
White Cliffs	29	29	—
Other	99	85	14
Total distributions received from unconsolidated affiliates	$ 379	$ 406	$ (27)

(1) For the year ended December 31, 2020, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by FEP, which reduced the Partnership’s equity in earnings by $208 million.

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

Segment Operating Results

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

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

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

In the following analysis of segment operating results, a measure of segment margin is reported for segments with sales revenues. Segment margin is a non-GAAP financial measure and is presented herein to assist in the analysis of segment operating results and particularly to facilitate an understanding of the impacts that changes in sales revenues have on the segment performance measure of Segment Adjusted EBITDA. Segment margin is similar to the GAAP measure of gross margin, except that segment margin excludes charges for depreciation, depletion and amortization. Among the GAAP measures reported by the Partnership, the most directly comparable measure to segment margin is Segment Adjusted EBITDA; a reconciliation of segment margin to Segment Adjusted EBITDA is included in the following tables for each segment where segment margin is presented.

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

Winter Storm Impacts

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. The recognition of the impacts of Winter Storm Uri during the year ended December 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.

For additional information regarding our business segments, see "Item 1. Business" and Notes 1 and 16 to our consolidated financial statements in "Item 8. Financial Statements and Supplementary Data."

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31, 2021	Years Ended December 31, 2020	Change
Natural gas transported (BBtu/d)	11,918	11,822	96
Withdrawals from storage natural gas inventory (BBtu)	32,038	22,613	9,425
Revenues	$ 8,571	$ 2,544	$ 6,027
Cost of products sold	4,769	1,478	3,291
Segment margin	3,802	1,066	2,736
Unrealized gains on commodity risk management activities	(46)	(25)	(21)
Operating expenses, excluding non-cash compensation expense	(268)	(177)	(91)
Selling, general and administrative expenses, excluding non-cash compensation expense	(36)	(28)	(8)
Adjusted EBITDA related to unconsolidated affiliates	27	25	2
Other	4	2	2
Segment Adjusted EBITDA	$ 3,483	$ 863	$ 2,620

Volumes. For the year ended December 31, 2021 compared to the prior year, transported volumes were relatively consistent with the prior year.

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

	Years Ended December 31, 2021	Years Ended December 31, 2020	Change
Transportation fees	$ 740	$ 617	$ 123
Natural gas sales and other (excluding unrealized gains and losses)	1,267	317	950
Retained fuel revenues (excluding unrealized gains and losses)	180	48	132
Storage margin, including fees (excluding unrealized gains and losses)	1,569	59	1,510
Unrealized gains on commodity risk management activities	46	25	21
Total segment margin	$ 3,802	$ 1,066	$ 2,736

Segment Adjusted EBITDA. For the year ended December 31, 2021 compared to the prior year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $1.51 billion in realized storage margin due to higher physical storage margin from withdrawals during Winter Storm Uri;
- an increase $950 million of in realized natural gas sales and other primarily due to natural gas sales during Winter Storm Uri;
- an increase of $132 million in retained fuel revenues primarily due to higher natural gas sales during Winter Storm Uri; and
- an increase of $123 million in transportation fees due to a $67 million increase in revenues from Winter Storm Uri, a $53 million increase from demand volume ramp-ups from the Permian, and a $16 million in incremental revenue from the Enable assets acquired in December 2021, partially offset by the expiration of certain contracts on Regency Intrastate Gas System; partially offset by
- an increase of $91 million in operating expenses primarily due to increases of $56 million in cost of fuel consumption, mostly during Winter Storm Uri, $15 million in maintenance project costs, $8 million in employee relate costs, $5 million in ad valorem taxes, $4 million in outside services and material costs, and $3 million in incremental expenses from operation of the Enable assets acquired in December 2021.

Interstate Transportation and Storage

	Years Ended December 31,		
	2021	2020	Change
Natural gas transported (BBtu/d)	10,310	10,329	(19)
Natural gas sold (BBtu/d)	23	16	7
Revenues	$ 1,841	$ 1,861	$ (20)
Cost of products sold	11	—	11
Segment margin	1,830	1,861	(31)
Operating expenses, excluding non-cash compensation, amortization, accretion and other non-cash expenses	(580)	(567)	(13)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(83)	(59)	(24)
Adjusted EBITDA related to unconsolidated affiliates	347	451	(104)
Other	1	(6)	7
Segment Adjusted EBITDA	$ 1,515	$ 1,680	$ (165)

Volumes. For the year ended December 31, 2021 compared to the prior year, transported volumes decreased primarily due to foundation shipper contract expirations and a shipper bankruptcy on our Tiger system and lower utilization of contracted capacity on our Trunkline system, partially offset by the impact of the Enable Acquisition.

Segment Adjusted EBITDA. For the year ended December 31, 2021 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $31 million in segment margin primarily due to a $127 million decrease resulting from shipper contract expirations on our Tiger system, a $55 million decrease due to a shipper bankruptcy during 2020 also on our Tiger system, and a $36 million decrease on our Panhandle and Trunkline systems due to lower demand. These decreases were partially offset by a $100 million increase in operational gas sales, a $50 million increase in transportation revenues from our Rover, Transwestern and Tiger systems due to increased demand and a $39 million increase due to the impact of the Enable Acquisition;
- an increase of $13 million in operating expenses primarily due to a $16 million increase due to the impact of the Enable Acquisition, a $20 million increase in ad valorem taxes due to refunds received in 2020 on Transwestern, a $17 million increase in employee related costs and a $14 million increase from the revaluation of system gas. These increases were partially offset by a $39 million decrease due to bad debt expense recorded in the prior period, a $7 million decrease in transportation expense and a $6 million decrease resulting from an inventory valuation adjustment in the prior period;
- an increase of $24 million in selling, general and administrative expenses primarily due to a $13 million impact resulting from a settlement related to excise taxes on Rover in the prior period and a $13 million increase in allocated overhead costs. These increases were partially offset by a $4 million decrease in professional fees; and
- a decrease of $104 million in Adjusted EBITDA related to unconsolidated affiliates due to a $75 million decrease from our Fayetteville Express Pipeline joint venture as a result of the expiration of foundation shipper contracts, a $21 million decrease from our Citrus joint venture due to a contractual rate adjustment and higher project expenses and a $10 million decrease from our Midcontinent Express Pipeline joint venture due to capacity sold at lower rates; partially offset by
- an increase of $7 million in other Adjusted EBITDA primarily due to certain one-time fees received in connection with the operation of a joint venture.

Midstream

	Years Ended December 31, 2021	Years Ended December 31, 2020	Change
Gathered volumes (BBtu/d)	13,230	12,961	269
NGLs produced (MBbls/d)	644	611	33
Equity NGLs (MBbls/d)	36	35	1
Revenues	$ 11,316	$ 5,026	$ 6,290
Cost of products sold	8,569	2,598	5,971
Segment margin	2,747	2,428	319
Unrealized gains on commodity risk management activities	(10)	—	(10)
Operating expenses, excluding non-cash compensation expense	(778)	(705)	(73)
Selling, general and administrative expenses, excluding non-cash compensation expense	(126)	(87)	(39)
Adjusted EBITDA related to unconsolidated affiliates	32	31	1
Other	3	3	—
Segment Adjusted EBITDA	$ 1,868	$ 1,670	$ 198

Volumes. For the year ended December 31, 2021 compared to the prior year, gathered volumes increased due to the Enable Acquisition. NGL production increased due to higher ethane recoveries in the South Texas region and the Enable Acquisition.

Segment Margin. The table below presents the components of our midstream segment margin.

	Years Ended December 31, 2021	Years Ended December 31, 2020	Change
Gathering and processing fee-based margin	$ 2,137	$ 2,187	$ (50)
Non-fee-based and processing margin	600	241	359
Unrealized gains on commodity risk management activities	10	—	10
Total segment margin	$ 2,747	$ 2,428	$ 319

Segment Adjusted EBITDA. For the year ended December 31, 2021 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $465 million in non-fee-based margin due to favorable NGL prices of $297 million and natural gas prices of $168 million; partially offset by
- a decrease of $106 million in non-fee-based margin due to the impacts of Winter Storm Uri of $143 million partially offset by volume growth of $27 million;
- a decrease of $50 million in fee-based margin due to the recognition of $103 million related to the restructuring and assignment of certain gathering and processing contracts in the Ark-La-Tex region in the third quarter of 2020, which included the recognition of $75 million of deferred revenue received in prior periods, partially offset by volume growth of $53 million, including the impact of the Enable Acquisition;
- an increase of $73 million in operating expenses primarily due to an increase of $42 million in employee costs and $22 million in incremental operating expenses from operation of the Enable assets acquired in December 2021; and
- an increase of $39 million in selling, general and administrative expenses primarily due to an increase of $21 million in allocated overhead costs and $15 million in incremental selling, general and administrative expenses from the Enable assets acquired in December 2021.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2021	2020	Change
NGL transportation volumes (MBbls/d)	1,732	1,436	296
Refined products transportation volumes (MBbls/d)	496	461	35
NGL and refined products terminal volumes (MBbls/d)	1,174	825	349
NGL fractionation volumes (MBbls/d)	835	835	—
Revenues	$ 19,961	$ 10,513	$ 9,448
Cost of products sold	16,248	7,139	9,109
Segment margin	3,713	3,374	339
Unrealized (gains) losses on commodity risk management activities	(88)	78	(166)
Operating expenses, excluding non-cash compensation expense	(784)	(650)	(134)
Selling, general and administrative expenses, excluding non-cash compensation expense	(112)	(82)	(30)
Adjusted EBITDA related to unconsolidated affiliates	97	82	15
Other	2	—	2
Segment Adjusted EBITDA	$ 2,828	$ 2,802	$ 26

Volumes. For the year ended December 31, 2021 compared to the prior year, NGL transportation volumes increased primarily due to the initiation of service on our propane and ethane export pipelines into our Nederland Terminal in the fourth quarter of 2020, higher volumes from the Eagle Ford region and higher volumes on our Mariner East pipeline system. These increases were partially offset by lower volumes caused by production interruptions, primarily in the Permian region, due to Winter Storm Uri during the first quarter of 2021.

Refined products transportation volumes increased for the year ended December 31, 2021 compared to prior year due to recovery from COVID-19 related demand reduction in the prior period.

NGL and refined products terminal volumes increased for the year ended December 31, 2021 compared to the prior year primarily due to the previously mentioned start of new pipelines and refined product demand recovery.

For the year ended December 31, 2021 compared to the prior year, average fractionated volumes at our Mont Belvieu, Texas fractionation facility reflected lower NGL volumes feeding our Mont Belvieu fractionation facility as a result of production interruptions, primarily in the Permian region, due to Winter Storm Uri during the first quarter of 2021; however, this reduction was substantially offset by impact from the commissioning of our seventh fractionator in February 2020.

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

	Years Ended December 31,		
	2021	2020	Change
Fractionators and refinery services margin	$ 712	$ 726	$ (14)
Transportation margin	2,016	1,895	121
Storage margin	271	250	21
Terminal Services margin	642	541	101
Marketing margin	(16)	40	(56)
Unrealized gains (losses) on commodity risk management activities	88	(78)	166
Total segment margin	$ 3,713	$ 3,374	$ 339

Segment Adjusted EBITDA. For the year ended December 31, 2021 compared to the prior 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 $121 million in transportation margin due to a $105 million increase due to higher export volumes feeding into our Nederland Terminal, a $40 million increase from higher throughput on our Mariner pipeline systems, a $35 million intrasegment gain related to cavern withdrawals which is offset in our fractionators margin, intrasegment capacity lease revenues of $25 million which are fully offset by a charge reflected in our marketing margin and an $18 million increase in refined products transportation due primarily to recovery from COVID-19 related demand reduction in the prior period. These increases were partially offset by an $88 million decrease resulting from increased utilization of our ethane optimization strategy and a $10 million decrease from volumetric losses on our Texas y-grade pipeline system;

- an increase of $101 million in terminal services margin primarily due to a $130 million increase from fees for loading export cargos at our Nederland Terminal, a $9 million increase due to higher throughput and storage at our refined product terminals due to recovery from COVID-19 related demand reduction in the prior period and other refined products demand increases and a $5 million increase due to higher throughput at our Marcus Hook Terminal. These increases were partially offset by a $44 million decrease resulting from an expiration of a third-party contract at our Nederland Terminal in the second quarter of 2020;
- an increase of $21 million in storage margin primarily due to a $31 million increase in fees generated from exported volumes and a $7 million increase in blending activity due to a more favorable pricing environment. These increases were partially offset by a $19 million decrease from component product storage fees; and
- an increase of $15 million in Adjusted EBITDA related to unconsolidated affiliates due to a $10 million increase primarily resulting from higher throughput on Explorer pipeline due to COVID-19 demand recovery and a $4 million increase from higher volumes on White Cliffs pipeline; partially offset by
- an increase of $134 million in operating expenses primarily due to a $74 million increase in utilities costs resulting from increased gas and power costs, a $32 million increase in employee costs resulting primarily from corporate cost reductions in 2020 in response to the COVID pandemic, a $20 million increase in allocated corporate overhead costs and a $7 million increase due to the timing of maintenance related expenses;
- a decrease of $56 million in marketing margin primarily due to a $29 million decrease from the optimization of NGL component products from our Gulf Coast NGL activities, intrasegment charges of $25 million which are fully offset within our transportation margin and a $3 million decrease from our northeast blending and optimization activity;
- an increase of $30 million in selling, general and administrative expenses primarily due to corporate cost reductions in 2020; and
- a decrease of $14 million in fractionators and refinery services margin primarily due to a $35 million intrasegment charge related to cavern withdrawals which is offset in our transportation margin and a $32 million decrease resulting from increased utilization of our ethane optimization strategy. These decreases were partially offset by a $37 million increase due to a more favorable pricing environment impacting our refinery services business and a $16 million increase from operational blending.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2021	2020	Change
Crude transportation volumes (MBbls/d)	3,886	3,763	123
Crude terminals volumes (MBbls/d)	2,567	2,576	(9)
Revenue	$ 17,446	$ 11,679	$ 5,767
Cost of products sold	14,759	8,838	5,921
Segment margin	2,687	2,841	(154)
Unrealized (gains) losses on commodity risk management activities	(4)	12	(16)
Operating expenses, excluding non-cash compensation expense	(547)	(526)	(21)
Selling, general and administrative expenses, excluding non-cash compensation expense	(135)	(118)	(17)
Adjusted EBITDA related to unconsolidated affiliates	19	37	(18)
Other	3	12	(9)
Segment Adjusted EBITDA	$ 2,023	$ 2,258	$ (235)

Volumes. For the year ended December 31, 2021 compared to the prior year, crude transportation volumes were higher on our Bakken pipeline and Bayou Bridge pipelines, reflecting the continuing recovery in crude oil production in North Dakota and more favorable crude oil differentials for shippers on Bayou Bridge. Volumes on our Texas pipeline system were slightly lower, primarily reflecting adverse weather negatively impacting volumes in the first quarter of 2021 and less favorable spreads for shippers to some markets in 2021. Crude terminal volumes were lower primarily due to reduced export demand at our Gulf Coast terminals.

Segment Adjusted EBITDA. For the year ended December 31, 2021 compared to the prior year, Segment Adjusted EBITDA related to our crude oil transportation and services segment decreased due to the net impacts of the following:

- a decrease of $170 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $167 million decrease from our Texas crude pipeline system due to lower average tariff rates realized, a $95 million decrease from our crude oil acquisition and marketing business primarily due to storage trading gains realized in the prior period and less favorable pricing conditions impacting our Bakken to Gulf Coast trading operations partially offset by favorable crude inventory valuation adjustments, and a $33 million decrease in throughput at our crude terminals primarily driven by reduced export demand; partially offset by a $6 million increase related to assets acquired in 2021, a $27 million increase due to higher volumes on our Bayou Bridge pipeline and a $95 million increase due to higher volumes on our Bakken Pipeline; and
- an increase of $21 million operating expenses primarily due to higher volume-driven expenses, higher employee expenses, and expenses related to assets acquired in 2021; and
- an increase of $17 million in selling, general and administrative expenses primarily due to higher allocations to the crude segment as a result of assets acquired, partially offset by lower legal expenses; and
- a decrease of $18 million in Adjusted EBITDA related to unconsolidated affiliates due to lower volumes on White Cliffs pipeline from lower crude oil production, partially offset by higher jet fuel sales by our joint ventures.

Investment in Sunoco LP

	Years Ended December 31,		
	2021	2020	Change
Revenues	$ 17,596	$ 10,710	$ 6,886
Cost of products sold	16,246	9,654	6,592
Segment margin	1,350	1,056	294
Unrealized (gains) losses on commodity risk management activities	(14)	6	(20)
Operating expenses, excluding non-cash compensation expense	(329)	(336)	7
Selling, general and administrative, excluding non-cash compensation expense	(93)	(98)	5
Adjusted EBITDA related to unconsolidated affiliates	9	10	(1)
Inventory valuation adjustments	(190)	82	(272)
Other, net	21	19	2
Segment Adjusted EBITDA	$ 754	$ 739	$ 15

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

Segment Adjusted EBITDA. For the year ended December 31, 2021 compared to the prior year, Segment Adjusted EBITDA related to the Investment in Sunoco LP segment increased due to the net impacts of the following:

- an increase in non motor fuel gross profit and lease income of $19 million, primarily due to an increase in storage tanks and terminals gross profit; and
- a decrease in operating costs of $12 million. These expenses include other operating expense, general and administrative expense and lease expense. The decrease was primarily due to lower expected credit losses, employee costs and consulting costs; partially offset by an increase in advertising costs, acquisitions costs and credit card costs; partially offset by
- a decrease in the gross profit on motor fuel sales of $14 million, primarily due to a 5.8% decrease in gross profit per gallon sold; partially offset by a 6.4% increase in gallons sold.

Investment in USAC

	Years Ended December 31,		
	2021	2020	Change
Revenues	$ 633	$ 667	$ (34)
Cost of products sold	85	82	3
Segment margin	548	585	(37)
Operating expenses, excluding non-cash compensation expense	(109)	(124)	15
Selling, general and administrative, excluding non-cash compensation expense	(41)	(51)	10
Other, net	—	4	(4)
Segment Adjusted EBITDA	$ 398	$ 414	$ (16)

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

Segment Adjusted EBITDA. For the year ended December 31, 2021 compared to last year, Segment Adjusted EBITDA related to our investment in USAC segment decreased due to the net impacts of the following:

- a decrease of $34 million in revenue was primarily due to a decrease in average revenue generating horsepower resulting from returns of compression units from its customers which USAC believes is primarily due to continued optimization of existing compression service requirements by USAC's customers, partially offset by compression units moving from standby to full billing rate since the previous periods; partially offset by
- a decrease of $15 million operating expenses was primarily due to an $8 million decrease in direct labor expenses and a $5 million decrease in non-income taxes, primarily due to sales tax refunds received in the current period related to prior periods, and
- a decrease of $10 million in selling, general and administrative expense was primarily due to a $6 million decrease in the provision for expected credit losses, a $2 million decrease in employee-related expenses and a $2 million decrease in severance charges primarily due to the departure of one of our executives during the prior period.

All Other

	Years Ended December 31,		
	2021	2020	Change
Revenue	$ 3,476	$ 1,838	$ 1,638
Cost of products sold	3,068	1,527	1,541
Segment margin	408	311	97
Unrealized losses on commodity risk management activities	—	1	(1)
Operating expenses, excluding non-cash compensation expense	(151)	(133)	(18)
Selling, general and administrative expenses, excluding non-cash compensation expense	(110)	(101)	(9)
Adjusted EBITDA related to unconsolidated affiliates	1	2	(1)
Other and eliminations	29	25	4
Segment Adjusted EBITDA	$ 177	$ 105	$ 72

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 year ended December 31, 2021 compared to the prior year, Segment Adjusted EBITDA increased due to the net impacts of the following:

- an increase of $58 million from power trading activities primarily due to short-term, favorable market conditions created by Winter Storm Uri in February of 2021;
- an increase of $25 million primarily due to revenues earned by our dual drive compression business under the Electric Reliability Council of Texas (“ERCOT”) responsive reserve program during Winter Storm Uri;
- an increase of $19 million due to improved margins at our dual drive compression business resulting from more favorable market pricing conditions;
- an increase of $12 million from Energy Transfer Canada due to the aggregate impact of multiples smaller changes;
- an increase of $9 million due to higher compressor sales and lower operating expenses in our compressor business; and
- an increase of $3 million due to a contract expiration at our natural resources business in 2020; partially offset by
- a decrease of $13 million due to higher power costs at our dual drive compression business;
- a decrease of $5 million in merger and acquisition expenses primarily driven by expenses related to the Enable Acquisition; and
- a decrease of $42 million from 2020 insurance proceeds received on settled claims related to our MTBE litigation.

Year Ended December 31, 2020 Compared to the Year Ended December 31, 2019

Consolidated Results

	Years Ended December 31,		
	2020	2019	Change
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 863	$ 999	$ (136)
Interstate transportation and storage	1,680	1,792	(112)
Midstream	1,670	1,602	68
NGL and refined products transportation and services	2,802	2,666	136
Crude oil transportation and services	2,258	2,898	(640)
Investment in Sunoco LP	739	665	74
Investment in USAC	414	420	(6)
All other	105	98	7
Total	10,531	11,140	(609)
Depreciation, depletion and amortization	(3,678)	(3,147)	(531)
Interest expense, net of interest capitalized	(2,327)	(2,331)	4
Impairment losses	(2,880)	(74)	(2,806)
Losses on interest rate derivatives	(203)	(241)	38
Non-cash compensation expense	(121)	(113)	(8)
Unrealized losses on commodity risk management activities	(71)	(5)	(66)
Inventory valuation adjustments	(82)	79	(161)
Losses on extinguishments of debt	(75)	(18)	(57)
Adjusted EBITDA related to unconsolidated affiliates	(628)	(626)	(2)
Equity in earnings of unconsolidated affiliates	119	302	(183)
Impairment of investments in unconsolidated affiliates	(129)	—	(129)
Other, net	(79)	54	(133)
Income before income tax expense	377	5,020	(4,643)
Income tax expense	(237)	(195)	(42)
Net income	$ 140	$ 4,825	$ (4,685)

Adjusted EBITDA (*consolidated*). For the year ended December 31, 2020 compared to the prior year, Adjusted EBITDA decreased 5.5%, primarily due to the impacts of lower volumes and market prices among several of our core operating segments resulting primarily from COVID-19 related demand reductions. These decreases were partially offset by an increase of $136 million from our NGL and refined products transportation and services segment primarily due to higher throughput volumes, an increase of $68 million from our midstream segment primarily due to the restructuring and assignment of certain gathering and processing contracts, and an increase of $74 million from our investment in Sunoco LP segment primarily due to increased gross profit per gallon sold and a decrease in operating costs. The decrease in Adjusted EBITDA was also offset by a net increase of approximately $569 million from recent acquisitions and assets placed in service.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased primarily due to additional depreciation from assets recently placed in service and recent acquisitions.

Interest Expense, Net of Interest Capitalized. Interest expense, net of interest capitalized, increased primarily due to the following:

- interest expenses recognized by the Partnership (excluding Sunoco LP and USAC) decreased by $8 million due to lower borrowing costs on both recently refinanced and floating rate debt, and higher capitalized interest offsetting a higher consolidated debt balance;
- an increase of $2 million recognized by USAC was primarily due to a full year of interest expense incurred in the current period on its senior notes 2027 issued in March 2019, partially offset by reduced borrowings and lower weighted average interest rates under its credit agreement; and

- an increase of $2 million recognized by Sunoco LP due to a slight increase in average long-term debt.

Impairment Losses. During the year ended December 31, 2020, the Partnership recognized goodwill impairments totaling $2.2 billion and fixed asset impairments totaling $58 million, primarily due to decreases in projected future cash flows as a result of overall market demand decline. In addition, USAC recognized a goodwill impairment of $619 million as well as an equipment impairment of $8 million based on changes in market conditions.

During the year ended December 31, 2019, the Partnership recognized goodwill impairments totaling $21 million primarily due to changes in assumptions related to projected future revenues and cash flows. Also during the year ended December 31, 2019, Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York, and USAC recognized a $6 million fixed asset impairment related to certain idle compressor assets.

Losses on Interest Rate Derivatives. Our interest rate derivatives are not designated as hedges for accounting purposes; therefore, changes in fair value are recorded in earnings each period. Losses on interest rate derivatives decreased by $38 million during the year ended December 31, 2020, compared to the prior year primarily due to a $400 million reduction in notional amount of outstanding forward-starting interest rate derivatives, which was partially offset by lower average interest rates and expenses related to the early termination and settlement of forward-starting interest rate derivatives.

Unrealized Gains (Losses) on Commodity Risk Management Activities. The unrealized gains and losses on our commodity risk management activities include changes in fair value of commodity derivatives and the hedged inventory included in designated fair value hedging relationships. Information on the unrealized gains and losses within each segment are included in “Segment Operating Results” below, and additional information on the commodity-related derivatives, including notional volumes, maturities and fair values, is available in “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” and in Note 14 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data.”

Inventory Valuation Adjustments. Inventory valuation reserve adjustments were recorded for the inventory associated with Sunoco LP primarily driven by changes in fuel prices between periods.

Losses on Extinguishments of Debt. Year ended December 31, 2020 amounts were related to Senior Note redemption in January 2020. In addition, Sunoco LP recognized a $13 million loss on extinguishment of debt related to the repurchase of its outstanding 2023 senior notes in 2020.

Impairment of Investments in Unconsolidated Affiliate. During the year ended December 31, 2020, the Partnership recorded an impairment to its investment in White Cliffs of $129 million due to a decrease in projected future revenues and cash flows as a result of the overall market demand decline that occurred subsequent to the SemGroup acquisition and related purchase price allocation in December 2019.

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

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

Income Tax Expense. For the year ended December 31, 2020 compared to the same period in the prior year, income tax expense increased due to higher earnings from the Partnership’s consolidated corporate subsidiaries in 2020 and the impact of a current state tax benefit (net of federal benefit) of $17 million in the prior year, which was primarily due to a change in estimate related to state

Supplemental Information on Unconsolidated Affiliates

The following table presents financial information related to unconsolidated affiliates:

	Years Ended December 31, 2020	Years Ended December 31, 2019	Change
Equity in earnings (losses) of unconsolidated affiliates:			
Citrus	$ 162	$ 148	$ 14
FEP [(1)]	(139)	59	(198)
MEP	(6)	15	(21)
White Cliffs	20	4	16
Other	82	76	6
Total equity in earnings of unconsolidated affiliates	$ 119	$ 302	$ (183)
Adjusted EBITDA related to unconsolidated affiliates[(2)]:			
Citrus	$ 347	$ 342	$ 5
FEP	76	75	1
MEP	28	60	(32)
White Cliffs	44	—	44
Other	133	149	(16)
Total Adjusted EBITDA related to unconsolidated affiliates	$ 628	$ 626	$ 2
Distributions received from unconsolidated affiliates:			
Citrus	$ 191	$ 178	$ 13
FEP	75	73	2
MEP	26	36	(10)
White Cliffs	29	5	24
Other	85	96	(11)
Total distributions received from unconsolidated affiliates	$ 406	$ 388	$ 18

(1) For the year ended December 31, 2020, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by FEP, which reduced the Partnership's equity in earnings by $208 million.

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

Segment Operating Results

Intrastate Transportation and Storage

	Years Ended December 31,		
	2020	2019	Change
Natural gas transported (BBtu/d)	11,822	11,805	17
Revenues	$ 2,544	$ 3,099	$ (555)
Cost of products sold	1,478	1,909	(431)
Segment margin	1,066	1,190	(124)
Unrealized (gains) losses on commodity risk management activities	(25)	2	(27)
Operating expenses, excluding non-cash compensation expense	(177)	(190)	13
Selling, general and administrative, excluding non-cash compensation expense	(28)	(29)	1
Adjusted EBITDA related to unconsolidated affiliates	25	25	—
Other	2	1	1
Segment Adjusted EBITDA	$ 863	$ 999	$ (136)

Volumes. For the year ended December 31, 2020 compared to the prior year, transported volumes were relatively consistent.

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

	Years Ended December 31,		
	2020	2019	Change
Transportation fees	$ 617	$ 614	$ 3
Natural gas sales and other (excluding unrealized gains and losses)	317	505	(188)
Retained fuel revenues (excluding unrealized gains and losses)	48	50	(2)
Storage margin, including fees (excluding unrealized gains and losses)	59	23	36
Unrealized gains (losses) on commodity risk management activities	25	(2)	27
Total segment margin	$ 1,066	$ 1,190	$ (124)

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to the prior year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $188 million in realized natural gas sales and other due to lower realized gains from pipeline optimization activity; and
- a decrease of $2 million in retained fuel revenues primarily due to lower natural gas prices; offset by
- an increase of $36 million in realized storage margin primarily due to higher realized gains on financial derivatives used to hedge physical storage gas;
- a decrease of $13 million in operating expenses primarily due to a $5 million decrease in outside services, a $4 million decrease in employee costs, a $3 million decrease in maintenance project costs and a $2 million decrease in ad valorem taxes; and
- an increase of $3 million in transportation fees primarily due to volume ramp-ups on Red Bluff Express pipeline and new contracts partially offset by the expansion of certain contracts on Regency Intrastate Gas Systems.

Interstate Transportation and Storage

	Years Ended December 31,		
	2020	2019	Change
Natural gas transported (BBtu/d)	10,329	11,346	(1,017)
Natural gas sold (BBtu/d)	16	17	(1)
Revenues	$ 1,861	$ 1,963	$ (102)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(567)	(569)	2
Selling, general and administrative, excluding non-cash compensation, amortization and accretion expenses	(59)	(72)	13
Adjusted EBITDA related to unconsolidated affiliates	451	477	(26)
Other	(6)	(7)	1
Segment Adjusted EBITDA	$ 1,680	$ 1,792	$ (112)

Volumes. For the year ended December 31, 2020 compared to the prior year, transported volumes decreased primarily due to lower crude production resulting in lower associated gas production and contract expirations on our Tiger Pipeline, as well as multiple weather events and maintenance of third-party facilities impacting our assets along the Gulf Coast.

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to the prior year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net impacts of the following:

- a decrease of $102 million in revenues primarily due to a decrease of $63 million from a contractual rate adjustment on commitments at our Lake Charles LNG facility effective January 2020, a decrease of $30 million due to additional revenue recognized in 2019 associated with a shipper bankruptcy, a decrease of $28 million due to lower utilization and lower rates on our Panhandle and Trunkline systems, a decrease of $12 million in transportation fees as a result of multiple weather events and maintenance on third-party facilities connected to our systems, and a decrease of $8 million resulting from contract expirations on ETC Tiger. These decreases were partially offset by higher reservation revenue on Transwestern and Rover resulting from higher contracted capacity and higher parking revenue resulting from timing of transactions; and
- a decrease of $26 million in Adjusted EBITDA related to unconsolidated affiliates primarily due to lower earnings from our Midcontinent Express Pipeline primarily as a result of lower rates received following the expiration of certain contracts, partially offset by an increase from Citrus primarily due to higher revenues resulting from new contracts, rate increases on existing contracts, the recognition of a contract exit fee and lower operating expenses; partially offset by
- a decrease of $2 million in operating expense primarily due to $22 million in refunds of ad valorem taxes on Transwestern and lower current year assessments, a $13 million decrease in employee costs and a $9 million decrease in maintenance project costs resulting from cost-cutting initiatives, partially offset by $38 million in bad debt expense associated with a shipper bankruptcy and a $5 million increase related to the valuation of inventory on Panhandle; and
- a decrease of $13 million in selling, general and administrative expenses primarily resulting from a $17 million favorable settlement related to excise taxes on Rover and a $5 million decrease in employee costs due to cost-cutting initiatives, partially offset by a $4 million increase in legal and consulting fees related to an ongoing rate case and shipper bankruptcies and a $3 million increase in allocated overhead costs.

Midstream

	Years Ended December 31, 2020	2019	Change
Gathered volumes (BBtu/d):	12,961	13,468	(507)
NGLs produced (MBbls/d):	611	571	40
Equity NGLs (MBbls/d):	35	31	4
Revenues	$ 5,026	$ 6,031	$ (1,005)
Cost of products sold	2,598	3,577	(979)
Segment margin	2,428	2,454	(26)
Operating expenses, excluding non-cash compensation expense	(705)	(791)	86
Selling, general and administrative, excluding non-cash compensation expense	(87)	(90)	3
Adjusted EBITDA related to unconsolidated affiliates	31	27	4
Other	3	2	1
Segment Adjusted EBITDA	$ 1,670	$ 1,602	$ 68

Volumes. For the year ended December 31, 2020 compared to the prior year, gathered volumes decreased primarily in the South Texas and Northeast regions, partially offset by the impact of the SemGroup acquisition in the Mid-Continent/Panhandle region and volume growth in the Ark-La-Tex and Permian regions. NGL production increased due to the impact of the SemGroup acquisition in the Mid-Continent/Panhandle region and ethane uplift in the Permian, South Texas and North Texas regions.

Segment Margin. The table below presents the components of our midstream segment margin.

	Years Ended December 31, 2020	2019	Change
Gathering and processing fee-based margin	$ 2,187	$ 2,132	$ 55
Non-fee-based and processing margin	241	322	(81)
Total segment margin	$ 2,428	$ 2,454	$ (26)

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to the prior year, Segment Adjusted EBITDA related to our midstream segment increased due to the net impacts of the following:

- an increase of $55 million in fee-based margin due to the impact of the SemGroup acquisition in the Mid-Continent/Panhandle region and recognized $103 million related to the restructuring and assignment of certain gathering and processing contracts in the Ark-La-Tex region, which included the recognition of $75 million of deferred revenue received in prior periods. This increase was partially offset by the impact of volume declines in the South Texas region;
- a decrease of $86 million in operating expenses due to cost-saving initiatives, including a decrease of $39 million in outside services, $25 million in materials, $14 million in employee costs and $8 million in office expenses; and
- a decrease of $3 million in selling, general and administrative expenses due to a decrease in allocated overhead costs resulting from overall corporate cost reductions; partially offset by
- a decrease of $70 million in non-fee-based margin due to unfavorable NGL prices of $75 million and favorable natural gas prices of $5 million; and
- a decrease of $11 million in non-fee-based margin due to decreased throughput volume, primarily in the South Texas region.

NGL and Refined Products Transportation and Services

	Years Ended December 31,		
	2020	2019	Change
NGL transportation volumes (MBbls/d)	1,436	1,289	147
Refined products transportation volumes (MBbls/d)	461	583	(122)
NGL and refined products terminal volumes (MBbls/d)	825	844	(19)
NGL fractionation volumes (MBbls/d)	835	706	129
Revenues	$ 10,513	$ 11,641	$ (1,128)
Cost of products sold	7,139	8,393	(1,254)
Segment margin	3,374	3,248	126
Unrealized losses on commodity risk management activities	78	81	(3)
Operating expenses, excluding non-cash compensation expense	(650)	(656)	6
Selling, general and administrative expenses, excluding non-cash compensation expense	(82)	(93)	11
Adjusted EBITDA related to unconsolidated affiliates	82	86	(4)
Segment Adjusted EBITDA	$ 2,802	$ 2,666	$ 136

Volumes. For the year ended December 31, 2020 compared to the prior year, NGL transportation volumes increased due to higher throughput volumes on our Mariner East pipeline system. In addition, throughput barrels on our Texas NGL pipeline system increased due to higher receipt of liquids production from both wholly-owned and third-party gas plants primarily in the Permian and North Texas regions, as well as higher export volumes feeding into our Nederland Terminal resulting from the initiation of service on our propane export pipeline in the fourth quarter of 2020.

Refined products transportation volumes decreased for the year ended December 31, 2020 compared to prior year due to the closure of a third-party refinery during the third quarter of 2019, which negatively impacted supply to our refined products transportation system, and less domestic demand for jet fuel and other refined products. These decreases in volumes were partially offset by the initiation of service of our JC Nolan diesel fuel pipeline in the third quarter of 2019.

NGL and refined products terminal volumes decreased for the year ended December 31, 2020 compared to the prior year primarily due to the closure of a third-party refinery during the third quarter of 2019 and less domestic demand for jet fuel and other refined products. These decreases were partially offset by higher volumes from our Mariner East system, an increase in loaded vessels at our Nederland Terminal, and the initiation of service on our JC Nolan diesel fuel pipeline and natural gasoline export project, both of which commences service in the third quarter of 2019.

Average fractionated volumes at our Mont Belvieu, Texas fractionation facility increased for the year ended December 31, 2020 compared to the prior year primarily due to the commissioning of our sixth and seventh fractionators in February 2019 and February 2020, respectively.

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

	Years Ended December 31,		
	2020	2019	Change
Fractionators and refinery services margin	$ 726	$ 664	$ 62
Transportation margin	1,895	1,716	179
Storage margin	250	223	27
Terminal Services margin	541	630	(89)
Marketing margin	40	96	(56)
Unrealized losses on commodity risk management activities	(78)	(81)	3
Total segment margin	$ 3,374	$ 3,248	$ 126

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to the prior 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 $179 million in transportation margin primarily due to a $128 million increase from higher throughput volumes on our Mariner East pipeline system, a $53 million increase from higher throughput volumes received from the Permian region, a $17 million increase due to the initiation of service on our JC Nolan diesel fuel pipeline in the third quarter of 2019, a $14 million increase from higher throughput volumes from the Barnett region, a $12 million increase from higher volumes from the South Texas region and a $3 million increase due to higher throughput on our Mariner West pipeline. These increases were partially offset by a $17 million decrease from lower throughput volumes received from the Eagle Ford region, a $16 million decrease due to less demand for jet fuel and other refined products, and a $13 million decrease resulting from the closure of a third-party refinery during the third quarter of 2019;
- an increase of $62 million in fractionators and refinery services margin primarily due to a $57 million increase resulting from the commissioning of our sixth and seventh fractionators in February 2019 and February 2020, respectively, and higher NGL volumes from the Permian and Barnett regions feeding our Mont Belvieu fractionation facility, and a $9 million increase in rail and truck volumes feeding our refinery services facility. These increases were partially offset by a $7 million decrease due primarily to an expiration of a third-party blending contract during the second quarter of 2020;
- an increase of $27 million in storage margin primarily due to a $16 million increase from throughput fees generated from exported volumes and an $11 million increase from component product storage fees; and
- a decrease of $11 million in selling, general and administrative expenses primarily due to lower allocated overhead costs and lower employee costs resulting from cost-cutting initiatives; partially offset by
- a decrease of $89 million in terminal services margin primarily due to a $90 million decrease resulting from an expiration of a third-party contract at our Nederland Terminal in the second quarter of 2020, a $29 million decrease due to lower third-party and intercompany volumes feeding our Marcus Hook Terminal, a $16 million decrease due to lower expense reimbursements in 2020, and a $14 million decrease due to less domestic demand for jet fuel and other refined products. These decreases were partially offset by a $60 million increase due to higher throughput on our Mariner East system; and
- a decrease of $56 million in marketing margin primarily due to an $87 million decrease due to lower margin from our butane blending business, a $37 million decrease in gasoline blending and optimization due primarily to unfavorable market conditions primarily attributable to the COVID-19 pandemic. These decreases were partially offset by a $47 million increase due to higher optimization gains from the sale of NGL component products at our Mont Belvieu facility and a $21 million increase in NGL export and rack volumes.

Crude Oil Transportation and Services

	Years Ended December 31,		
	2020	2019	Change
Crude Transportation Volumes (MBbls/d)	3,763	4,217	(454)
Crude Terminals Volumes (MBbls/d)	2,576	2,513	63
Revenue	$ 11,679	$ 18,447	$ (6,768)
Cost of products sold	8,838	14,832	(5,994)
Segment margin	2,841	3,615	(774)
Unrealized (gains) losses on commodity risk management activities	12	(69)	81
Operating expenses, excluding non-cash compensation expense	(526)	(570)	44
Selling, general and administrative expenses, excluding non-cash compensation expense	(118)	(85)	(33)
Adjusted EBITDA related to unconsolidated affiliates	37	8	29
Other	12	(1)	13
Segment Adjusted EBITDA	$ 2,258	$ 2,898	$ (640)

Volumes. For the year ended December 31, 2020 compared to the prior year, crude transportation volumes were lower on our Texas pipeline system and our Bakken pipeline, driven by lower production in these regions due to lower crude oil prices as well as lower refinery utilization caused by COVID-19 demand destruction, partially offset by contributions from assets acquired in 2019. Crude terminal volumes were higher due to contributions from assets acquired in 2019, partially offset by lower Permian and Bakken pipeline volumes, reduced refinery utilization, and reduced export demand at our Nederland Terminal.

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to the prior year, Segment Adjusted EBITDA related to our crude oil transportation and services segment decreased due to the net impacts of the following:

- a decrease of $693 million in segment margin (excluding unrealized gains and losses on commodity risk management activities) primarily due to a $430 million decrease from our Texas crude pipeline system due to lower utilization and lower average tariff rates realized, a $286 million decrease (excluding a net change of $84 million in unrealized gains and losses on commodity risk management activities) from our crude oil acquisition and marketing business primarily due to a significant contraction in spreads in 2020 as compared to 2019 primarily impacting our Permian to Gulf Coast and Bakken to Gulf Coast trading operations, a $224 million decrease due to lower volumes on our Bakken Pipeline due to lower basin production, and a $35 million decrease in throughput at our crude terminals primarily driven by lower Permian and Bakken volumes, reduced refinery utilization from COVID-19 demand destruction, reduced export demand, and hurricanes impacting operations in the third quarter of 2020; partially offset by a $285 million increase related to assets acquired in 2019; and
- an increase of $33 million in selling, general and administrative expenses primarily due to legal expenses, higher insurance expenses, and an increase related to assets acquired in 2019; partially offset by
- a decrease of $44 million in operating expenses primarily due to lower volume-driven pipeline expenses and corporate cost-cutting initiatives, partially offset by increased costs related to assets acquired in 2019; and
- an increase of $29 million in Adjusted EBITDA related to unconsolidated affiliates due to assets acquired in 2019.

Investment in Sunoco LP

	Years Ended December 31,		
	2020	2019	Change
Revenues	$ 10,710	$ 16,596	$ (5,886)
Cost of products sold	9,654	15,380	(5,726)
Segment margin	1,056	1,216	(160)
Unrealized (gains) losses on commodity risk management activities	6	(5)	11
Operating expenses, excluding non-cash compensation expense	(336)	(365)	29
Selling, general and administrative, excluding non-cash compensation expense	(98)	(123)	25
Adjusted EBITDA related to unconsolidated affiliates	10	4	6
Inventory valuation adjustments	82	(79)	161
Other, net	19	17	2
Segment Adjusted EBITDA	$ 739	$ 665	$ 74

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

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to the prior year, Segment Adjusted EBITDA related to the 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 $32 million, primarily due to a 18% increase in gross profit per gallon sold and the receipt of a $13 million make-up payment under Sunoco LP's fuel supply agreement with 7-Eleven, Inc., partially offset by a 13% decrease in gallons sold; and
- a decrease of $54 million in operating expenses and selling, general and administrative expenses, excluding non-cash compensation expense, primarily attributable to lower employee costs, maintenance, advertising, credit card fees and utilities, which was partially offset by a $12 million charge for current expected credit losses on Sunoco LP's accounts receivable in connection with the financial impact from COVID-19; and
- an increase of $6 million in Adjusted EBITDA related to unconsolidated affiliates due to Sunoco LP's investment in the JC Nolan joint venture; partially offset by
- a decrease of $18 million in non-motor fuel sales and lease gross profit primarily due to reduced credit card transactions related to the COVID-19 pandemic and rent concessions in 2020.

Investment in USAC

	Years Ended December 31,		
	2020	2019	Change
Revenues	$ 667	$ 698	$ (31)
Cost of products sold	82	91	(9)
Segment margin	585	607	(22)
Operating expenses, excluding non-cash compensation expense	(124)	(134)	10
Selling, general and administrative, excluding non-cash compensation expense	(51)	(53)	2
Other, net	4	—	4
Segment Adjusted EBITDA	$ 414	$ 420	$ (6)

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

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to last year, Segment Adjusted EBITDA related to our investment in USAC segment increased due to the net impacts of the following:

- a decrease of $10 million in operating expenses primarily driven by a decrease in average revenue generating horsepower and reduced headcount; partially offset by
- a decrease of $22 million in segment margin primarily driven by a decrease in revenues primarily due to a decrease in average revenue generating horsepower as a result of a decline in demand for compression services primarily driven by a decrease in U.S. crude oil and natural gas activities and a reduction of ancillary maintenance work, offset by a decrease in costs of products sold of $9 million.

All Other

	Years Ended December 31,		
	2020	2019	Change
Revenue	$ 1,838	$ 1,689	$ 149
Cost of products sold	1,527	1,504	23
Segment margin	311	185	126
Unrealized (gains) losses on commodity risk management activities	1	(4)	5
Operating expenses, excluding non-cash compensation expense	(133)	(77)	(56)
Selling, general and administrative expenses, excluding non-cash compensation expense	(101)	(66)	(35)
Adjusted EBITDA related to unconsolidated affiliates	2	2	—
Other and eliminations	25	58	(33)
Segment Adjusted EBITDA	$ 105	$ 98	$ 7

Amounts reflected in our all other segment during the periods presented above 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 were acquired in the SemGroup acquisition in December 2019 and include natural gas gathering and processing assets.

Segment Adjusted EBITDA. For the year ended December 31, 2020 compared to the prior year, Segment Adjusted EBITDA increased due to the net impacts of the following:

- an increase of $97 million from the acquisition of Energy Transfer Canada; and
- an increase of $26 million primarily due to insurance proceeds received on settled claims related to our MTBE litigation; partially offset by

- a decrease of $22 million due to lower coal royalties and producer demand from our natural resources business;
- a decrease of $35 million due to lower revenue from our compressor equipment business;
- a decrease of $12 million from adverse market conditions due to COVID-19 related demand destruction;
- a decrease of $28 million due to higher merger and acquisition expenses;
- a decrease of $10 million due to intercompany eliminations; and
- a decrease of $6 million due to the elimination of Sunoco LP’s interest in the JC Nolan Joint Venture.

LIQUIDITY AND CAPITAL RESOURCES

Our ability to satisfy our 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. The significant trends and uncertainties that we currently believe could significantly impact our liquidity and cash flows going forward are discussed in “Trends and Outlook” above.

We believe that we have sufficient liquidity and sources of funding to meet our cash requirements over the near term and for the longer term. We expect to satisfy our working capital needs through cash generated by our operations, along with cash on hand and borrowings under our Five-Year Credit Facility. As of December 31, 2021, we had cash and cash equivalents of $336 million and availability under our revolving credit facility of $2.03 billion.

The Partnership’s material contractual obligations include long-term debt service, payments under operating leases, and purchase commitments. The Partnership’s obligations under its long-term debt agreements are described below under “Description of Indebtedness,” and information on the maturities and interest rates related to the Partnership’s long-term debt is available in Note 6 to the consolidated financial statements in “Item 8. Financial Statements and Supplementary Data.” In addition, information on the Partnership’s obligations under its lease arrangements is included in Note 13 to the consolidated financial statements in Item 8.

We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. We have material purchase commitments for crude oil; as of December 31, 2021, those purchase commitments totaled an estimated $13.34 billion (of which $10.44 billion would be due in 2022) based on either the current market price for variable price contracts or the contracted price for fixed price contracts.

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	$ 75	$ 100	$ 40	$ 45
Interstate transportation and storage (1)	375	425	160	170
Midstream	600	675	130	140
NGL and refined products transportation and services (1)	350	400	120	125
Crude oil transportation and services (1)	100	150	105	115
All other (including eliminations)	100	150	60	70
Total capital expenditures	$ 1,600	$ 1,900	$ 615	$ 665

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

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

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

Sunoco LP expects to invest at least $150 million in growth capital expenditures and approximately $50 million on maintenance capital expenditures in 2022.

USAC currently plans to spend approximately $23 million in maintenance capital expenditures and currently has budgeted between $110 million and $120 million in expansion capital expenditures in 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 of our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions, and other factors.

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and 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 acquisitions of assets, while changes in non-cash compensation expense resulted from changes in the number of units granted and changes in the grant date fair value 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 Energy Transfer has a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of derivative assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchases and sales of inventories, and the timing of advances and deposits received from customers.

Following is a summary of operating activities by period:

Year Ended December 31, 2021

Cash provided by operating activities in 2021 was $11.16 billion and net income was $6.69 billion. The difference between net income and cash provided by operating activities in 2021 primarily consisted of non-cash items totaling $3.80 billion offset by net changes in operating assets and liabilities of $515 million. The non-cash activity in 2021 consisted primarily of depreciation, depletion and amortization of $3.82 billion, impairment losses of $21 million, non-cash compensation expense of $111 million, equity in earnings of unconsolidated affiliates of $246 million, inventory valuation adjustments of $190 million, losses on extinguishment of debt of $38 million, and deferred income taxes of $141 million. The Partnership also received distributions of $212 million from unconsolidated affiliates.

Year Ended December 31, 2020

Cash provided by operating activities in 2020 was $7.36 billion and net income was $140 million. The difference between net income and cash provided by operating activities in 2020 primarily consisted of non-cash items totaling $7.00 billion offset by net changes in operating assets and liabilities of $47 million. The non-cash activity in 2020 consisted primarily of depreciation, depletion and amortization of $3.68 billion, impairment losses of $2.88 billion, non-cash compensation expense of $121 million, equity in earnings of unconsolidated affiliates of $119 million, inventory valuation adjustments of $82 million, losses on extinguishment of debt of $75 million, and deferred income taxes of $210 million. The Partnership also received distributions of $220 million from unconsolidated affiliates.

Year Ended December 31, 2019

Cash provided by operating activities in 2019 was $8.06 billion and net income was $4.83 billion. The difference between net income and cash provided by operating activities in 2019 primarily consisted of non-cash items totaling $3.37 billion and net changes in operating assets and liabilities of $391 million. The non-cash activity in 2019 consisted primarily of depreciation, depletion and amortization of $3.15 billion, impairment losses of $74 million, non-cash compensation expense of $113 million, equity in earnings of unconsolidated affiliates of $302 million, inventory valuation adjustments of $79 million, losses on extinguishment of debt of $18 million, and deferred income taxes of $217 million. The Partnership also received distributions of $290 million from unconsolidated affiliates.

Investing Activities

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

Following is a summary of investing activities by period:

Year Ended December 31, 2021

Cash used in investing activities in 2021 was $2.78 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $2.78 billion. Additional detail related to our capital expenditures is provided in the table below. We received $45 million of cash proceeds from the sale of assets. The Partnership received $51 million of net cash from the Enable Acquisition. The Partnership also received distributions of $167 million from unconsolidated affiliates. We paid $256 million in cash for all other acquisitions.

Year Ended December 31, 2020

Cash used in investing activities in 2020 was $4.90 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $5.06 billion. Additional detail related to our capital expenditures is provided in the table below. We received $19 million of cash proceeds from the sale of assets. The Partnership also received distributions of $187 million from unconsolidated affiliates.

Year Ended December 31, 2019

Cash used in investing activities in 2019 was $6.93 billion. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) were $5.88 billion. Additional detail related to our capital expenditures is provided in the table below. During 2019, we received $93 million of cash proceeds from the sale of a noncontrolling interest in a subsidiary, paid $787 million in net cash for the SemGroup acquisition, and paid $7 million in cash for all other acquisitions. We received $54 million of cash proceeds from the sale of assets. The Partnership also received distributions of $98 million from unconsolidated affiliates.

The following is a summary of the Partnership's capital expenditures (including only our proportionate share of the Bakken, Rover, and Bayou Bridge pipeline projects, our proportionate share of the Orbit Gulf Coast NGL export project, and net of contributions in aid of construction costs) by period:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Year Ended December 31, 2021:			
Intrastate transportation and storage	$ 17	$ 35	$ 52
Interstate transportation and storage	35	124	159
Midstream	365	119	484
NGL and refined products transportation and services	637	114	751
Crude oil transportation and services	250	93	343
Investment in Sunoco LP	135	39	174
Investment in USAC	40	20	60
All other (including eliminations)	98	37	135
Total capital expenditures	$ 1,577	$ 581	$ 2,158
Year Ended December 31, 2020:			
Intrastate transportation and storage	$ 13	$ 36	$ 49
Interstate transportation and storage	52	98	150
Midstream	376	111	487
NGL and refined products transportation and services	2,305	98	2,403
Crude oil transportation and services	209	82	291
Investment in Sunoco LP	89	35	124
Investment in USAC	96	23	119
All other (including eliminations)	99	37	136
Total capital expenditures	$ 3,239	$ 520	$ 3,759
Year Ended December 31, 2019:			
Intrastate transportation and storage	$ 87	$ 37	$ 124
Interstate transportation and storage	239	136	375
Midstream	670	157	827
NGL and refined products transportation and services	2,854	122	2,976
Crude oil transportation and services	317	86	403
Investment in Sunoco LP	108	40	148
Investment in USAC	170	30	200
All other (including eliminations)	165	50	215
Total capital expenditures	$ 4,610	$ 658	$ 5,268

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 to partners increased between the periods as a result of increases in the number of common units outstanding or increases in the distribution rate.

Following is a summary of financing activities by period:

Year Ended December 31, 2021

Cash used in financing activities was $8.42 billion in 2021. In 2021, we had a net decrease in our debt level of $6.05 billion. During 2021, we paid distributions of $1.90 billion to our partners, we paid distributions of $1.49 billion to noncontrolling interests, and we paid distributions of $49 million to our redeemable noncontrolling interests. In addition, we received capital contributions of $226 million in cash from noncontrolling interests. During 2021, we incurred debt issuance costs of $14 million. During 2021, we received $889 million from offerings of preferred units.

Year Ended December 31, 2020

Cash used in financing activities was $2.39 billion in 2020. In 2020, our subsidiaries received $1.58 billion in proceeds from the issuance of preferred units. In 2020, we had a net increase in our debt level of $307 million, primarily due to the issuance of subsidiary notes. During 2020, we paid distributions of $2.80 billion to our partners, we paid distributions of $1.65 billion to noncontrolling interests, and we paid distributions of $49 million to our redeemable noncontrolling interests. In addition, we received capital contributions of $222 million in cash from noncontrolling interests. During 2020, we incurred debt issuance costs of $59 million.

Year Ended December 31, 2019

Cash used in financing activities was $1.25 billion in 2019. Our subsidiaries received $780 million in proceeds from the issuance of preferred units. In 2019, we had a net increase in our debt level of $2.48 billion, primarily due to the issuance of subsidiary notes. During 2019, we paid distributions of $3.05 billion to our partners, we paid distributions of $1.60 billion to noncontrolling interests, and we paid distributions of $53 million to our redeemable noncontrolling interests. In addition, we received capital contributions of $348 million in cash from noncontrolling interests. During 2019, we incurred debt issuance costs of $117 million.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	December 31,	
	2021	2020
Energy Transfer Indebtedness:		
Notes and Debentures [1]	$ 37,733	$ 37,855
Term Loan [2]	—	2,000
Five-Year Credit Facility [2]	2,937	3,103
Subsidiary Indebtedness:		
Transwestern Senior Notes	400	400
Panhandle Notes and Debentures	235	235
Bakken Senior Notes [3]	2,500	2,500
Sunoco LP Senior Notes and lease-related obligations	2,700	3,139
USAC Senior Notes	1,475	1,475
HFOTCO Tax Exempt Notes	225	225
Revolving Credit Facilities:		
Sunoco LP Credit Facility	581	—
USAC Credit Facility	516	474
Energy Transfer Canada Revolving Credit Facility	7	57
Energy Transfer Canada KAPS Facility	142	—
Energy Transfer Canada Term Loan A	249	261
Other long-term debt	3	3
Net unamortized premiums, discounts and fair value adjustments	238	(10)
Deferred debt issuance costs	(239)	(279)
Total debt	49,702	51,438
Less: current maturities of long-term debt	680	21
Long-term debt, less current maturities	$ 49,022	$ 51,417

(1) The December 31, 2020 balance presented above includes senior notes that were formerly obligations of ETO prior to the Rollup Mergers discussed below and in “Recent Developments” above. As of March 31, 2021 and December 31, 2020, the outstanding principal amount of ETO senior notes was $36.4 billion and $37.8 billion, respectively. Beginning April 1, 2021, these senior notes are obligations of Energy Transfer.

(2) The Term Loan and Five-Year Credit Facility were previously obligations of ETO. Subsequent to the completion of the Rollup Mergers on April 1, 2021, these facilities became obligations of Energy Transfer. The Term Loan has subsequently been terminated.

(3) The balance includes $650 million of 3.625% Senior Notes due April 2022 included in current maturities of long-term debt as of December 31, 2021.

The terms of our consolidated indebtedness and that of our subsidiaries are described in more detail below and in Note 6 to our consolidated financial statements, included in “Item 8. Financial Statements and Supplementary Data.”

Recent Financing Transactions

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

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

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

During the fourth quarter of 2021, Energy Transfer redeemed its $1.0 billion aggregate principal amount of 5.2% senior notes due February 1, 2022, and $900 million aggregate principal amount of 5.875% senior notes due March 1, 2022.

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

In connection with the Enable Acquisition on December 2, 2021, as discussed in Note 3 to our consolidated financial statements in “Item 8. Financial Statements and Supplementary Data,” Energy Transfer repaid $800 million outstanding on the Enable 2019 Term Loan Agreement and $35 million outstanding on the Enable Five-Year Revolving Credit Facility, and both facilities were terminated. In addition, the Partnership assumed $3.18 billion aggregate principal amount of Enable senior notes.

Credit Facilities and Commercial Paper

Term Loan

As a result of the Rollup Mergers, on April 1, 2021, Energy Transfer assumed all of ETO’s obligations in respect of its term loan credit agreement, and the facility was subsequently repaid and terminated.

Five-Year Credit Facility

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

As of December 31, 2021, the Five-Year Credit Facility had $2.94 billion of outstanding borrowings, of which $1.19 billion consisted of commercial paper. The amount available for future borrowings was $2.03 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 December 31, 2021 was 1.13%.

364-Day Facility

As a result of the Rollup Mergers, on April 1, 2021, Energy Transfer assumed all of ETO’s obligations in respect of its 364-day revolving credit facility, and the facility was subsequently terminated.

Sunoco LP Credit Facility

As of December 31, 2021, the Sunoco LP Credit Facility had $581 million outstanding borrowings and $6 million in standby letters of credit and matures in July 2023. The amount available for future borrowings was $0.9 billion at December 31, 2021. The weighted average interest rate on the total amount outstanding as of December 31, 2021 was 2.10%.

USAC Credit Facility

As of December 31, 2021, USAC had $516 million of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2021, USAC had $1.1 billion of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $262 million. The weighted average interest rate on the total amount outstanding as of December 31, 2021 was 2.68%.

Energy Transfer Canada Credit Facilities

As of December 31, 2021, the Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility had outstanding borrowings of C$315 million and C$9 million, respectively (US$249 million and US$7 million, respectively, at the December 31, 2021 exchange rate). As of December 31, 2021, the KAPS Facility had outstanding borrowings of C$179 million (US$142 million at the December 31, 2021 exchange rate).

Covenants Related to Our Credit Agreements

The agreements relating to the Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions.

The Five-Year Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in the Five-Year Credit Facility) during certain Defaults (as defined in the Five-Year Credit Facility) and during any Event of Default (as defined in the Five-Year Credit Facility);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements.

The applicable margin and rate used in connection with the interest rates and commitment fees, respectively, are based on the credit ratings assigned to our senior, unsecured, non-credit enhanced long-term debt. The applicable margin for eurodollar rate loans under the Five-Year Credit Facility ranges from 1.125% to 2.000% and the applicable margin for base rate loans ranges from 0.125% to 1.000%. The applicable rate for commitment fees under the Five-Year Credit Facility ranges from 0.125% to 0.300%.

The Five-Year Credit Facility contains various covenants including limitations on the creation of indebtedness and liens and related to the operation and conduct of our business. The Five-Year Credit Facility also limits us, on a rolling four quarter basis, to a maximum Consolidated Funded Indebtedness to Consolidated EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1 during a Specified Acquisition Period. Our Leverage Ratio was 3.07 to 1 at December 31, 2021, as calculated in accordance with the credit agreement.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Partnership's or our subsidiaries' ability to incur additional debt and/or our ability to pay distributions to Unitholders.

Covenants Related to Transwestern

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Covenants Related to Panhandle

Panhandle is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of Panhandle's lending agreements.

Panhandle's restrictive covenants include restrictions on liens securing debt and guarantees and restrictions on mergers and on the sales of assets. A breach of any of these covenants could result in acceleration of Panhandle's debt.

Covenants Related to Sunoco LP

The Sunoco LP Credit Facility contains various customary representations, warranties, covenants and events of default, including a change of control event of default, as defined therein. Sunoco LP's Credit Facility requires Sunoco LP to maintain a Net Leverage Ratio of not more than 5.5 to 1. The maximum Net Leverage Ratio is subject to upwards adjustment of not more than 6.0 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in certain specified acquisitions of not less than $50 million (as permitted under Sunoco LP's Credit Facility agreement). The Sunoco LP Credit Facility also requires Sunoco LP to maintain an Interest Coverage Ratio (as defined in the Sunoco LP's Credit Facility agreement) of not less than 2.25 to 1.

Covenants Related to USAC

The USAC Credit Facility contains covenants that limit (subject to certain exceptions) USAC's ability to, among other things:

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- enter into transactions with affiliates;
- merge or consolidate;
- sell our assets; and
- make certain acquisitions.

The credit facility is also subject to the following financial covenants, including covenants requiring USAC to maintain:

- a minimum EBITDA to interest coverage ratio of 2.5 to 1.0, determined as of the last day of each fiscal quarter, with EBITDA and interest expense annualized for the fiscal quarter most recently ended;
- a ratio of total secured indebtedness to EBITDA not greater than 3.0 to 1.0 or less than 0.0 to 1.0, determined as of the last day of each fiscal quarter, with EBITDA annualized for the fiscal quarter most recently ended; and
- a maximum funded debt to EBITDA ratio, determined as of the last day of each fiscal quarter with EBITDA annualized for the fiscal quarter most recently ended, (i) 5.75 to 1 through the second fiscal quarter of 2022, (ii) 5.5 to 1 from the third quarter of 2022 through the third quarter of 2023, and (iii) 5.25 to 1 thereafter. In addition, USAC may increase the applicable ratio by 0.25 for any fiscal quarter during which a Specified Acquisition (as defined in the Credit Agreement) occurs and the following two fiscal quarters, but in no event shall the maximum ratio exceed 5.5 to 1.0 for any fiscal quarter as a result of such increase.

Covenants Related to the HFOTCO Tax Exempt Notes

The indentures covering HFOTCO's tax exempt notes due 2050 ("IKE Bonds") include customary representations and warranties and affirmative and negative covenants. Such covenants include limitations on the creation of new liens, indebtedness, making of certain restricted payments and payments on indebtedness, making certain dispositions, making material changes in business activities, making fundamental changes including liquidations, mergers or consolidations, making certain investments, entering into certain transactions with affiliates, making amendments to certain credit or organizational agreements, modifying the fiscal year, creating or dealing with hazardous materials in certain ways, entering into certain hedging arrangements, entering into certain restrictive agreements, funding or engaging in sanctioned activities, taking actions or causing the trustee to take actions that materially adversely affect the rights, interests, remedies or security of the bondholders, taking actions to remove the trustee, making certain amendments to the bond documents, and taking actions or omitting to take actions that adversely impact the tax exempt status of the IKE Bonds.

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 December 31, 2021.

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.

Distributions declared and paid with respect to Energy Transfer common units were as follows:

Quarter Ended	Record Date	Payment Date	Rate	
December 31, 2018	February 8, 2019	February 19, 2019	$	0.3050
March 31, 2019	May 7, 2019	May 20, 2019		0.3050
June 30, 2019	August 6, 2019	August 19, 2019		0.3050
September 30, 2019	November 5, 2019	November 19, 2019		0.3050
December 31, 2019	February 7, 2020	February 19, 2020		0.3050
March 31, 2020	May 7, 2020	May 19, 2020		0.3050
June 30, 2020	August 7, 2020	August 19, 2020		0.3050
September 30, 2020	November 6, 2020	November 19, 2020		0.1525
December 31, 2020	February 8, 2021	February 19, 2021		0.1525
March 31, 2021	May 11, 2021	May 19, 2021		0.1525
June 30, 2021	August 6, 2021	August 19, 2021		0.1525
September 30, 2021	November 5, 2021	November 19, 2021		0.1525
December 31, 2021	February 8, 2022	February 18, 2022		0.1750

The total amounts of distributions declared and paid during the periods presented (all from Available Cash from Energy Transfer's operating surplus and are shown in the period to which they relate) are as follows:

	Years Ended December 31,		
	2021	2020	2019
Limited Partners	$ 1,777	$ 2,468	$ 3,221
General Partner interest	2	3	4
Total Energy Transfer distributions	$ 1,779	$ 2,471	$ 3,225

Energy Transfer Preferred Unit Distributions

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

Distributions on Energy Transfer's Series A, Series B, Series C, Series D, Series E, Series F, Series G and Series H preferred units declared and/or paid by Energy Transfer were as follows:

Period Ended	Record Date	Payment Date	Series A (1)	Series B (1)	Series C	Series D	Series E	Series F (1)	Series G (1)	Series H (1)	
March 31, 2021	May 3, 2021	May 17, 2021	$—	$—	$0.4609	$0.4766	$0.4750	$33.75	$35.63	$—	
June 30, 2021	August 2, 2021	August 16, 2021	31.25	33.13	0.4609	0.4766	0.4750	—	—	—	
September 30, 2021	November 1, 2021	November 15, 2021	—	—	0.4609	0.4766	0.4750	33.75	35.63	27.08	*
December 31, 2021	February 1, 2022	February 15, 2022	31.25	33.13	0.4609	0.4766	0.4750	—	—	—	

* Represents prorated initial distribution.

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

Sunoco LP Cash Distributions

The following table illustrates the percentage allocations of available cash from operating surplus between Sunoco LP's common unitholders and the holder of its IDRs based on the specified target distribution levels, after the payment of distributions to Class C unitholders. The amounts set forth under "marginal percentage interest in distributions" are the percentage interests of the IDR holder and the common unitholders in any available cash from operating surplus which Sunoco LP distributes up to and including the corresponding amount in the column "total quarterly distribution per unit target amount." The percentage interests shown for common unitholders and IDR holder for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Common Unitholders	Holder of IDRs
Minimum Quarterly Distribution	$0.4375	100%	—%
First Target Distribution	$0.4375 to $0.503125	100%	—%
Second Target Distribution	$0.503125 to $0.546875	85%	15%
Third Target Distribution	$0.546875 to $0.656250	75%	25%
Thereafter	Above $0.656250	50%	50%

Distributions on Sunoco LP's units declared and/or paid by Sunoco LP were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2018	February 6, 2019	February 14, 2019	$ 0.8255
March 31, 2019	May 7, 2019	May 15, 2019	0.8255
June 30, 2019	August 6, 2019	August 14, 2019	0.8255
September 30, 2019	November 5, 2019	November 19, 2019	0.8255
December 31, 2019	February 7, 2020	February 19, 2020	0.8255
March 31, 2020	May 7, 2020	May 19, 2020	0.8255
June 30, 2020	August 7, 2020	August 19, 2020	0.8255
September 30, 2020	November 6, 2020	November 19, 2020	0.8255
December 31, 2020	February 8, 2021	February 19, 2021	0.8255
March 31, 2021	May 11, 2021	May 19, 2021	0.8255
June 30, 2021	August 6, 2021	August 19, 2021	0.8255
September 30, 2021	November 5, 2021	November 19, 2021	0.8255
December 31, 2021	February 8, 2022	February 18, 2022	0.8255

The total amount of distributions to the Partnership from Sunoco LP for the periods presented below is as follows:

	Years Ended December 31,		
	2021	2020	2019
Distributions from Sunoco LP			
Limited Partner interests	$ 94	$ 94	$ 94
General Partner interest and IDRs	71	70	70
Total distributions from Sunoco LP	$ 165	$ 164	$ 164

USAC Cash Distributions

Energy Transfer owns approximately 46.1 million USAC common units. As of December 31, 2021, USAC had approximately 97.3 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding IDRs.

Distributions on USAC's units declared and/or paid by USAC subsequent to the USAC transaction on April 2, 2018 were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2018	January 28, 2019	February 8, 2019	$ 0.5250
March 31, 2019	April 29, 2019	May 10, 2019	0.5250
June 30, 2019	July 29, 2019	August 9, 2019	0.5250
September 30, 2019	October 28, 2019	November 8, 2019	0.5250
December 31, 2019	January 27, 2020	February 7, 2020	0.5250
March 31, 2020	April 27, 2020	May 8, 2020	0.5250
June 30, 2020	July 31, 2020	August 10, 2020	0.5250
September 30, 2020	October 26, 2020	November 6, 2020	0.5250
December 31, 2020	January 25, 2021	February 5, 2021	0.5250
March 31, 2021	April 26, 2021	May 7, 2021	0.5250
June 30, 2021	July 26, 2021	August 6, 2021	0.5250
September 30, 2021	October 25, 2021	November 5, 2021	0.5250
December 31, 2021	January 24, 2022	February 4, 2022	0.5250

The total amount of distributions to the Partnership from USAC for the periods presented below is as follows:

	Years Ended December 31,		
	2021	2020	2019
Distributions from USAC			
Limited Partner interests	$ 97	$ 97	$ 90
Total distributions from USAC	$ 97	$ 97	$ 90

Critical Accounting Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules, and we believe the proper implementation and consistent application of the accounting rules are critical. Our critical accounting policies are discussed below. For further details on our accounting policies see Note 2 to our consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2021 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation, depletion and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Fair Value Estimates in Business Combination Accounting and Impairment of Long-Lived Assets, Goodwill, Intangible Assets and Investments in Unconsolidated Affiliates. Business combination accounting and quantitative impairment testing are required from time to time due to the occurrence of events, changes in circumstances, or annual testing requirements. For business combinations, assets and liabilities are required to be recorded at estimated fair value in connection with the initial recognition of the transaction. For impairment testing, long-lived assets are required to be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Goodwill and intangibles with indefinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment of an investment in an unconsolidated affiliate is recognized when circumstances indicate that a decline in the investment value is other than temporary. An impairment loss should be recognized only if the carrying amount of the asset/goodwill is not recoverable and exceeds its fair value. Calculating the fair value of assets or reporting units in connection with business combination accounting or impairment testing requires management to make several estimates, assumptions and judgements, and in some circumstances management may also utilize third-party specialists to assist and advise on those calculations.

In order to allocate the purchase price in a business combination or to test for recoverability when performing a quantitative impairment test, we must make estimates of projected cash flows related to the asset, which include, but are not limited to, assumptions about the use or disposition of the asset, estimated remaining life of the asset, and future expenditures necessary to maintain the asset's existing service potential. In order to determine fair value, we make certain estimates and assumptions, including, among other things, changes in general economic conditions in regions in which our markets are located, the availability and prices of commodities, our ability to negotiate favorable sales agreements, the risks that exploration and production activities will not occur or be successful, our dependence on certain significant customers and producers, and competition from other companies, including major energy producers. While we believe we have made reasonable assumptions to calculate the fair value, if future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations.

The Partnership determines the fair value of its assets and/or reporting units using a discounted cash flow method, the guideline company method, the reproduction and replacement methods, or a weighted combination of these methods. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The Partnership believes the estimates and assumptions used in our business combination accounting and impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the Partnership determines fair value based on estimated future cash flows of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflect the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur. Under the guideline company method, the Partnership determines the estimated fair value of each of our reporting units by applying valuation multiples of comparable publicly-traded companies to each reporting unit's projected EBITDA and then averaging that estimate with similar historical calculations using a multi-year average. In addition, the Partnership estimates a reasonable control premium, when appropriate, representing the incremental value that accrues to the majority owner from the opportunity to dictate the strategic and operational actions of the business. Under the reproduction and replacement methods, the Partnership determines the fair value of assets based on the estimated installation, engineering, and set-up costs related to the asset; these methods require the use of trend factors, such as inflation indices.

One key assumption in these fair value calculations is management's estimate of future cash flows and EBITDA. In accounting for a business combination, these estimates are generally based on the forecasts that were used to analyze the deal economics. For impairment testing, these estimates are based on the annual budget for the upcoming year and forecasted amounts for multiple subsequent years. The annual budget process is typically completed near the annual goodwill impairment testing date, and management uses the most recent information for the annual impairment tests. The forecast is also subjected to a comprehensive update annually in conjunction with the annual budget process and is revised periodically to reflect new information and/or revised expectations. The estimates of future cash flows and EBITDA are subjective in nature and are subject to impacts from the business risks described in “Item 1A. Risk Factors.” Therefore, the actual results could differ significantly from the amounts used for business combination accounting and impairment testing, and significant changes in fair value estimates could occur in a given period. Such changes in fair value estimates could result in changes to the fair value estimates used in business combination accounting, which could significantly impact results of operations in a period subsequent to the business combination, depending on multiple factors, including the timing of such changes. In the case of impairment testing, such changes could result in additional impairments in future periods; therefore, the actual results could differ significantly from the amounts used for goodwill impairment testing, and significant changes in fair value estimates could occur in a given period, resulting in additional impairments.

In addition, we may change our method of impairment testing, including changing the weight assigned to different valuation models. Such changes could be driven by various factors, including the level of precision or availability of data for our assumptions. Any changes in the method of testing could also result in an impairment or impact the magnitude of an impairment.

During the years ended December 31, 2021, 2020 and 2019, the Partnership recorded total assets of $8.58 billion, $12 million and $6.06 billion, respectively, in connection with business combinations.

During the years ended December 31, 2020 and 2019, the Partnership recorded impairments totaling $3.01 billion and $74 million, respectively, including $129 million in impairments in unconsolidated affiliates in 2020, and $66 million and $53 million of long-lived asset impairments in 2020 and 2019, respectively. Additional information on the impairments recorded during these periods is available in “Item 8. Financial Statements and Supplementary Data.”

Estimated Useful Lives of Long-Lived Assets. Depreciation and amortization of long-lived assets is provided using the straight-line method based on their estimated useful lives. Changes in the estimated useful lives of the assets could have a material effect on our results of operation. The Partnership’s results of operations have not been significantly impacted by changes in the estimated useful lives of our long-lived assets during the periods presented, and we do not anticipate any such significant changes in the future. However, changes in facts and circumstances could cause us to change the estimated useful lives of the assets, which could significantly impact the Partnership’s results of operations. Additional information on our accounting policies and the estimated useful lives associated with our long-lived assets is available in “Item 8. Financial Statements and Supplementary Data.”

Legal and Regulatory Matters. We are subject to litigation and regulatory proceedings as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from claims, orders, judgments or settlements. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. We expense legal costs as incurred, and all recorded legal liabilities are revised, as required, as better information becomes available to us. The factors we consider when recording an accrual for contingencies include, among others: (i) the opinions and views of our legal counsel; (ii) our previous experience; and (iii) the decision of our management as to how we intend to respond to the complaints. As of December 31, 2021 and 2020, accruals of $144 million and $101 million, respectively, were reflected in our consolidated balance sheets related to these contingent obligations.

For more information on our litigation and contingencies, see Note 11 to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data” in this report.

Environmental Remediation Activities. The Partnership’s accrual for environmental remediation activities reflects anticipated work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. The accrual for known claims is undiscounted and is based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. It is often extremely difficult to develop reasonable estimates of future site remediation costs due to changing regulations, changing technologies and their associated costs, and changes in the economic environment. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated accruals for environmental remediation activities.

Losses attributable to unasserted claims are generally reflected in the accruals on an undiscounted basis, to the extent they are probable of occurrence and reasonably estimable. 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.

In general, each remediation site/issue is evaluated individually based upon information available for the site/issue and no pooling or statistical analysis is used to evaluate an aggregate risk for a group of similar items (e.g., service station sites) in determining the amount of probable loss accrual to be recorded. The Partnership's estimates of environmental remediation costs also frequently involve evaluation of a range of estimates. In many cases, it is difficult to determine that one point in the range of loss estimates is more likely than any other. In these situations, existing accounting guidance requires that the minimum of the range be accrued. Accordingly, the low end of the range often represents the amount of loss which has been recorded. The Partnership's consolidated balance sheet reflected $293 million and $306 million in environmental accruals as of December 31, 2021 and 2020, respectively.

Total future costs for environmental remediation activities will depend upon, among other things, the identification of any additional sites, the determination of the extent of the contamination at each site, the timing and nature of required remedial actions, the nature of operations at each site, the technology available and needed to meet the various existing legal requirements, the nature and terms of cost-sharing arrangements with other potentially responsible parties, the availability of insurance coverage, the nature and extent of future environmental laws and regulations, inflation rates, terms of consent agreements or remediation permits with regulatory agencies and the determination of the Partnership's liability at the sites, if any, in light of the number, participation level and financial viability of the other parties. The recognition of additional losses, if and when they were to occur, would likely extend over many years. Management believes that the Partnership's exposure to adverse developments with respect to any individual site is not expected to be material. However, if changes in environmental laws or regulations occur or the assumptions used to estimate losses at multiple sites are adjusted, such changes could impact multiple facilities, formerly owned facilities and third-party sites at the same time. As a result, from time to time, significant charges against income for environmental remediation may occur; however, management does not believe that any such charges would have a material adverse impact on the Partnership's consolidated financial position.

Deferred Income Taxes. Energy Transfer recognizes benefits in earnings and related deferred tax assets for net operating loss carryforwards ("NOLs") and tax credit carryforwards. If necessary, a charge to earnings and a related valuation allowance are recorded to reduce deferred tax assets to an amount that is more likely than not to be realized by the Partnership in the future. Deferred income tax assets attributable to state and federal NOLs and federal excess business interest expense carryforwards totaling $803 million have been included in Energy Transfer's consolidated balance sheet as of December 31, 2021. The state NOL carryforward benefits of $146 million ($116 million net of federal benefit) began expiring in 2021 with a substantial portion expiring between 2033 and 2039. Energy Transfer's corporate subsidiaries have federal NOLs of $3.0 billion ($646 million in benefits) of which $1.1 billion will expire between 2031 and 2037. A total of $338 million of the federal net operating loss carryforward is limited under IRC §382. Although we expect to fully utilize the IRC §382 limited federal net operating loss, the amount utilized in a particular year may be limited. Any federal NOL generated in 2018 and future years can be carried forward indefinitely. We have determined that a valuation allowance totaling $12 million ($9 million net of federal income tax effects) is required for state NOLs as of December 31, 2021 primarily due to significant restrictions on their use in the Commonwealth of Pennsylvania. A separate valuation allowance of $25 million is attributable to foreign tax credits. In making the assessment of the future realization of the deferred tax assets, we rely on future reversals of existing taxable temporary differences, tax planning strategies and forecasted taxable income based on historical and projected future operating results. The potential need for valuation allowances is regularly reviewed by management. If it is more likely than not that the recorded asset will not be realized, additional valuation allowances which increase income tax expense may be recognized in the period such determination is made. Likewise, if it is more likely than not that additional deferred tax assets will be realized, an adjustment to the deferred tax asset will increase income in the period such determination is made.

Forward-Looking Statements

This annual 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 annual report, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend," "could," "believe," "may," "will" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our General Partner can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Among the key risk factors that may have a direct bearing on our results of operations and financial condition are:

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

- the volumes transported on our subsidiaries' pipelines and gathering systems;
- the level of throughput in our subsidiaries' processing and treating facilities;
- the fees our subsidiaries charge and the margins they realize for their gathering, treating, processing, storage and transportation services;
- the prices and market demand for, and the relationship between, natural gas and NGLs;
- energy prices generally;
- impacts of world health events, including the COVID-19 pandemic;
- the prices of natural gas and NGLs compared to the price of alternative and competing fuels;
- the general level of petroleum product demand and the availability and price of NGL supplies;
- the level of domestic oil, natural gas and NGL production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of petroleum producing nations;
- the effect of weather conditions on demand for oil, natural gas and NGLs;
- availability of local, intrastate and interstate transportation systems;
- the continued ability to find and contract for new sources of natural gas supply;
- availability and marketing of competitive fuels;
- the impact of energy conservation efforts;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- changes to, and the application of, regulation of tariff rates and operational requirements related to our subsidiaries' interstate and intrastate pipelines;
- hazards or operating risks incidental to the gathering, treating, processing and transporting of natural gas and NGLs;
- competition from other midstream companies and interstate pipeline companies;
- loss of key personnel;
- loss of key natural gas producers or the providers of fractionation services;
- reductions in the capacity or allocations of third-party pipelines that connect with our subsidiaries pipelines and facilities;
- the effectiveness of risk-management policies and procedures and the ability of our subsidiaries liquids marketing counterparties to satisfy their financial commitments;
- the nonpayment or nonperformance by our subsidiaries' customers;
- regulatory, environmental, political and legal uncertainties that may affect the timing and cost of our subsidiaries' internal growth projects, such as our subsidiaries' construction of additional pipeline systems;
- risks associated with the construction of new pipelines and treating and processing facilities or additions to our subsidiaries' 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 subsidiaries' ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- risks associated with the assets and operations of entities in which our subsidiaries own a noncontrolling interests, including risks related to management actions at such entities that our subsidiaries may not be able to control or exert influence;
- the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses;

- changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations or new interpretations by regulatory agencies concerning such laws and regulations; and
- the costs and effects of legal and administrative proceedings.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risks described under “Item 1A. Risk Factors” in this annual report. Any forward-looking statement made by us in this Annual Report on Form 10-K 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 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

(Tabular dollar amounts are in millions)

Market risk includes the risk of loss arising from adverse changes in market rates and prices. We face market risk from commodity variations, risk and interest rate variations, and to a lesser extent, credit risks. From time to time, we may utilize derivative financial instruments as described below to manage our exposure to such risks.

Commodity Price Risk

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

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

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

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

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

We use 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 tables below summarize commodity-related financial derivative instruments, fair values and the effect of an assumed hypothetical 10% change in the underlying price of the commodity as of December 31, 2021 and 2020 for the Partnership and its consolidated subsidiaries. Dollar amounts are presented in millions.

	December 31, 2021			December 31, 2020		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (BBtu):						
Fixed Swaps/Futures	585	$ —	$ —	1,603	$ —	$ —
Basis Swaps IFERC/NYMEX[1]	(66,665)	(5)	1	(44,225)	2	5
Power (Megawatt):						
Forwards	653,000	2	—	1,392,400	4	—
Futures	(604,920)	2	2	18,706	(1)	—
Options – Puts	(7,859)	—	—	519,071	—	—
Options – Calls	(30,932)	—	—	2,343,293	1	—
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	6,738	1	1	(29,173)	—	1
Swing Swaps IFERC	(106,333)	32	31	11,208	(2)	—
Fixed Swaps/Futures	(63,898)	(24)	38	(53,575)	6	31
Forward Physical Contracts	(5,950)	1	—	(11,861)	4	5
NGL (MBbls) – Forwards/Swaps	8,493	12	19	(5,840)	(100)	39
Crude (MBbls) – Forwards/Swaps	3,672	13	2	—	—	—
Refined Products (MBbls) – Futures	(3,349)	(15)	32	(2,765)	(8)	3
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (BBtu):						
Basis Swaps IFERC/NYMEX	(40,533)	1	—	(30,113)	(1)	—
Fixed Swaps/Futures	(40,533)	41	14	(30,113)	(6)	8

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

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

Interest Rate Risk

As of December 31, 2021, our subsidiaries had $5.12 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $51 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 were designated as hedges for accounting purposes (dollar amounts presented in millions):

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

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

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

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

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains (losses) on interest rate derivatives) of $250 million as of December 31, 2021. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

LIBOR Phase-Out

As of December 31, 2021, we had outstanding approximately $5.3 billion of debt that bears interest at variable interest rates that use the LIBOR as a benchmark rate. In July 2017, the U.K.'s Financial Conduct Authority (FCA), which oversees the LIBOR submission process for all currencies and regulates the authorized administrator of LIBOR, ICE Benchmark Administration (IBA), announced that it intends to stop persuading or compelling London banks to make these rate submissions after 2021. The cessation date for compulsory submission and publication of rates for certain tenors of LIBOR has since been extended by the IBA and FCA until June 2023.

It is unclear if certain LIBOR tenors continue to be reported beyond 2021, whether they will be considered representative or whether an identified successor benchmark rate will attain market acceptance as a replacement for LIBOR. The adoption of an alternative benchmark rate and replacement for LIBOR could affect our debt securities, derivative instruments, receivables, debt payments and receipts. However, at this time, we do not anticipate a material impact from the potential establishment of any alternative benchmark rate(s).

Credit Risk and Customers

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

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements starting on page F-1 of this report are incorporated by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including Marshall S. McCrea, III and Thomas E. Long, Co-Chief Executive Officers of our General Partner (Co-Principal Executive Officers), and Bradford D. Whitehurst (Principal Financial Officer), of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including Messrs. McCrea, Long and Whitehurst, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2021.

Management's Report on Internal Control over Financial Reporting

The management of Energy Transfer LP and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the Co-Chief Executive Officers and Chief Financial Officer of our General Partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO Framework").

On December 2, 2021, ET acquired Enable. Management acknowledges that it is responsible for establishing and maintaining a system of internal controls over financial reporting for Enable. We are in the process of integrating Enable, and we therefore have excluded Enable from our December 31, 2021 assessment of the effectiveness of internal control over financial reporting. Enable had total assets of $8.3 billion as of December 31, 2021 and third-party revenues of $331 million from December 3, 2021 to December 31, 2021, which are included in our consolidated financial statements as of and for the year ended December 31, 2021. The impact of the acquisition of Enable has not materially affected and is not expected to materially affect our internal control over financial reporting. As a result of these integration activities, certain controls are being evaluated and may be changed. We believe, however, that we will be able to maintain sufficient controls over the substantive results of our financial reporting throughout this integration process.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2021.

Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2021, as stated in their report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of LE GP, LLC and
Unitholders of Energy Transfer LP

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Energy Transfer LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2021, and our report dated February 18, 2022 expressed an unqualified opinion on those financial statements.

Basis for opinion
The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Our audit of, and opinion on, the Partnership's internal control over financial reporting does not include the internal control over financial reporting of Enable Midstream Partners, LP ("Enable"), a consolidated subsidiary, whose financial statements reflect total assets and revenues constituting 8 and 0.5 percent, respectively, of the related consolidated financial statement amount as of and for the year ended December 31, 2021. As indicated in Management's Report on Internal Control over Financial Reporting, Enable was acquired during 2021. Management's assertion on the effectiveness of the Partnership's internal control over financial reporting excluded internal control over financial reporting of Enable.

Definition and limitations of internal control over financial reporting
A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 18, 2022

Changes in Internal Controls over Financial Reporting

There has been no change in our internal controls over financial reporting (as defined in Rules 13a–15(f) or Rule 15d–15(f)) that occurred in the three months ended December 31, 2021 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

Our general partner, LE GP, LLC, manages and directs all of our activities. The officers and directors of Energy Transfer are officers and directors of LE GP, LLC. The members of our general partner elect our general partner's Board of Directors. The board of directors of our general partner has the authority to appoint our executive officers, subject to provisions in the limited liability company agreement of our general partner. Pursuant to other authority, the board of directors of our general partner may appoint additional management personnel to assist in the management of our operations and, in the event of the death, resignation or removal of our chief executive officer, to appoint a replacement.

As of January 1, 2022, our Board of Directors is comprised of 11 persons, six of whom qualify as "independent" under the NYSE's corporate governance standards. As a limited partnership, we are not required under the NYSE's corporate governance standards (Section 303A) to have a majority of independent directors. We have determined that Messrs. Anderson, Brannon, Davis, Grimm, Perry and Washburne are all "independent" under the NYSE's corporate governance standards.

As a limited partnership, we are not required by the rules of the NYSE to seek Unitholder approval for the election of any of our directors. We believe that the members of our general partner have appointed as directors individuals with experience, skills and qualifications relevant to the business of Energy Transfer, such as experience in energy or related industries or with financial markets, expertise in natural gas operations or finance, and a history of service in senior leadership positions. We do not have a formal process for identifying director nominees, nor do we have a formal policy regarding consideration of diversity in identifying director nominees, but we believe that the members of our general partner have endeavored to assemble a group of individuals with the qualities and attributes required to provide effective oversight of the Energy Transfer.

Board Leadership Structure. We have no policy requiring either that the positions of the Chairman of the Board and the Chief Executive Officer, or CEO, be separate or that they be occupied by the same individual. The Board of Directors believes that this issue is properly addressed as part of the succession planning process and that a determination on this subject should be made when it elects a new chief executive officer or at such other times as when consideration of the matter is warranted by circumstances. Previously, the Board of Directors believed that the CEO was best situated to serve as Chairman because he was the director most familiar with the Partnership's business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Beginning in 2021, the Board of Directors has established separate roles for the Executive Chairman and Co-Chief Executive Officers. Independent directors and management have different perspectives and roles in strategy development. Our independent directors bring experience, oversight and expertise from outside the Partnership and from a variety of industries, while the Executive Chairman and Co-Chief Executive Officers bring extensive experience and expertise specifically related to the Partnership's business.

Risk Oversight. Our Board of Directors generally administers its risk oversight function through the board as a whole. Our Co-CEOs, who report to the Board of Directors, have day-to-day risk management responsibilities. Our Co-CEOs attend the meetings of our Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations, and other aspects of implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, at each regular meeting of the Board, management provides a report of Energy Transfer's financial and operational performance, which often prompts questions or feedback from the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from Energy Transfer's internal auditor, who reports directly to the Audit Committee, and reviews Energy Transfer's contingencies with management and our independent auditors.

Corporate Governance

The Board of Directors has adopted both a Code of Business Conduct and Ethics applicable to our directors, officers and employees, and Corporate Governance Guidelines for directors and the Board. Current copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines and charters of the Audit and Compensation Committees of our Board of Directors are available on our website at www.energytransfer.com and will be provided in print form to any Unitholder requesting such information.

Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found and/or provided at such Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Annual Certification

In 2021, our Chief Executive Officer provided to the NYSE the annual CEO certification regarding our compliance with the NYSE's corporate governance listing standards.

Conflicts Committee

Our Partnership Agreement provides that the Board of Directors may, from time to time, appoint members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the general partner is fair and reasonable to Energy Transfer and our Unitholders. As a policy matter, the Conflicts Committee generally reviews any proposed related-party transaction that may be material to Energy Transfer to determine if the transaction presents a conflict of interest and whether the transaction is fair and reasonable to Energy Transfer. Pursuant to the terms of our partnership agreement, any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Energy Transfer, approved by all partners of Energy Transfer and not a breach by the general partner or its Board of Directors of any duties they may owe Energy Transfer or the Unitholders. These duties are limited by our Partnership Agreement (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors appoints persons who are independent under the NYSE's standards for audit committee members to serve on its Audit Committee. In addition, the Board determines that at least one member of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 407(d)(5) of Regulation S-K. The Board determined that based on relevant experience, Audit Committee member Michael K. Grimm qualified as an audit committee financial expert during 2021. A description of the qualifications of Mr. Grimm may be found elsewhere in this Item 10 under "Directors and Executive Officers of the General Partner."

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, engage and direct our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by auditing standards*,* and approves the filing of our Form 10-K, which includes our audited financial statements. The Audit Committee periodically recommends to the Board of Directors any changes or modifications to its charter that may be required. The Audit Committee has received written disclosures and the letter from Grant Thornton required by applicable requirements of the Audit Committee concerning independence and has discussed with Grant Thornton that firm's independence. The Audit Committee recommended to the Board that the audited financial statements of Energy Transfer be included in Energy Transfer's Annual Report on Form 10-K for the year ended December 31, 2021.

The Board of Directors adopts the charter for the Audit Committee. Steven R. Anderson, Richard D. Brannon and Michael K. Grimm serve as elected members of the Audit Committee.

Compensation and Nominating/Corporate Governance Committees

Although we are not required under NYSE rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, the Board of Directors of LE GP, LLC has previously established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers under the equity compensation plans, including the performance standards or other restrictions pertaining to the vesting of any such awards. Messrs. Anderson, Grimm and Washburne serve as members of the Compensation Committee.

Matters relating to the nomination of directors or corporate governance matters were addressed to and determined by the full Board of Directors for the period Energy Transfer did not have a compensation committee.

The responsibilities of the Energy Transfer Compensation Committee include, among other duties, the following:

- annually review and approve goals and objectives relevant to compensation of our CEO and CFO, if applicable;

- annually evaluate the CEO and CFO's performance in light of these goals and objectives, and make recommendations to the Board of Directors with respect to the CEO and CFO's compensation levels, if applicable, based on this evaluation;
- make determinations with respect to the grant of equity-based awards to executive officers under Energy Transfer's equity incentive plans;
- periodically evaluate the terms and administration of Energy Transfer's long-term incentive plans to assure that they are structured and administered in a manner consistent with Energy Transfer's goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO and CFO or executive officer compensation; and
- perform other duties as deemed appropriate by the Board of Directors.

Code of Business Conduct and Ethics

The Board of Directors has adopted a Code of Business Conduct and Ethics applicable to our officers, directors and employees. Specific provisions are applicable to the co-principal executive officers, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our general partner. Amendments to, or waivers from, the Code of Business Conduct and Ethics will be available on our website and reported as may be required under SEC rules. Any technical, administrative or other non-substantive amendments to the Code of Business Conduct and Ethics may not be posted.

Meetings of Non-management Directors and Communications with Directors

Our non-management directors meet in regularly scheduled sessions. Our non-management directors alternate as the presiding director of such meetings.

We have established a procedure by which Unitholders or interested parties may communicate directly with the Board of Directors, any committee of the Board, any of the independent directors, or any one director serving on the Board of Directors by sending written correspondence addressed to the desired person, committee or group to the attention of Sonia Aubé at Energy Transfer LP 8111 Westchester Drive, Suite 600, Dallas, Texas, 75225. Communications are distributed to the Board of Directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our general partner as of February 18, 2022. Executive officers and directors are elected for indefinite terms.

Name	Age	Position with Our General Partner
Kelcy L. Warren	66	Executive Chairman of the Board of Directors
Thomas E. Long	65	Co-Chief Executive Officer and Director (Co-Principal Executive Officer)
Marshall S. (Mackie) McCrea, III	62	Co-Chief Executive Officer and Director (Co-Principal Executive Officer)
Bradford D. Whitehurst	47	Chief Financial Officer (Principal Financial Officer)
Matthew S. Ramsey	66	Chief Operating Officer and Director
Thomas P. Mason	65	Executive Vice President, General Counsel and President - LNG
A. Troy Sturrock	51	Senior Vice President and Controller (Principal Accounting Officer)
Steven R. Anderson	72	Director
Richard D. Brannon	63	Director
Ray C. Davis	80	Director
Michael K. Grimm	67	Director
John W. McReynolds	71	Director
James R. (Rick) Perry	71	Director
Ray W. Washburne	61	Director

Mr. Ramsey serves as chairman of the board of the general partner of Sunoco LP. Mr. Long serves as a director of the board of the general partners of Sunoco LP and of USAC. Mr. Mason and Mr. Whitehurst serve as directors of the general partner of USAC.

Set forth below is biographical information regarding the foregoing officers and directors of our general partner:

Kelcy L. Warren. Mr. Warren serves as Executive Chairman of our general partner. Mr. Warren served as Chief Executive Officer from August 2007 through December 2020. He was appointed Co-Chairman of the Board of Directors of our general partner, effective upon the closing of our IPO, and in August 2007, he became the sole Chairman of the Board of our general partner and the Chief Executive Officer and Chairman of the Board of the general partner of ETO until its merger into Energy Transfer LP in April 2021. Prior to August 2007, Mr. Warren had served as Co-Chief Executive Officer and Co-Chairman of the Board of the general partner of ETO since the combination of the midstream and intrastate transportation storage operations of La Grange Acquisition, L.P. and the retail propane operations of Heritage in January 2004. Mr. Warren also served as the Chief Executive Officer of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Mr. Warren was selected to serve as a director and as Executive Chairman because he previously served as Chief Executive Officer and has more than 30 years in the natural gas industry. Mr. Warren also has relationships with chief executives and other senior management at natural gas transportation companies throughout the United States and brings a unique and valuable perspective to the Board of Directors.

Thomas E. Long. Mr. Long has served as the Co-Chief Executive Officer of our general partner since January 2021. Mr. Long served as Chief Financial Officer of Energy Transfer's general partner from February 2016 until January 2021, and has been a director of our general partner since April 2019. Mr. Long also served as the Chief Financial Officer and as a director of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Mr. Long also served as Chief Financial Officer of ETO until its merger into Energy Transfer LP in April 2021, and was previously Executive Vice President and Chief Financial Officer of Regency GP LLC from November 2010 to April 2015. Mr. Long served as a director of Sunoco LP from May 2016 until May 2021, and has served as Chairman of the Board of USAC since April 2018. Mr. Long was selected to serve on our Board of Directors because of his understanding of energy-related corporate finance gained through his extensive experience in the energy industry.

Marshall S. (Mackie) McCrea, III. Mr. McCrea has served as the Co-Chief Executive Officer of our general partner since January 2021. Prior to that he was the President and Chief Commercial Officer of our general partner, having served in that role since October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. Prior to that time, he had been the Group Chief Operating Officer and Chief Commercial Officer of the Energy Transfer family since November 2015. Mr. McCrea has served on the Board of Directors of our general partner since December 2009. Mr. McCrea was appointed as a director of the general partner of ETO in December 2009 and served in that capacity until ETO's merger into Energy Transfer LP in April 2021. Prior to December 2009, he served as President and Chief Operating Officer of ETO's general partner from June 2008 to November 2015 and President – Midstream from March 2007 to June 2008. Previously he served as the Senior Vice President – Commercial Development since January 2004. In March 2005, Mr. McCrea was named President of La Grange Acquisition LP, ETO's primary operating subsidiary, after serving as Senior Vice President-Business Development and Producer Services since 1997. Mr. McCrea also served as the Chairman of the Board of Directors of the general partner of Sunoco Logistics Partners L.P. from October 2012 to April 2017. Mr. McCrea was selected to serve as a director because he brings extensive project development and operational experience to the Board. He has held various positions in the natural gas business over the past 25 years and is able to assist the Board of Directors in creating and executing the Partnership's strategic plan.

Bradford D. Whitehurst. Mr. Whitehurst was appointed Chief Financial Officer of Energy Transfer in January 2021. From August 2014 through December 2020 he served as Executive Vice President – Head of Tax. Prior to joining Energy Transfer, Mr. Whitehurst was a partner in the Washington, DC office of Bingham McCutchen LLP and an attorney in the Washington, DC offices of both McKee Nelson LLP and Hogan & Hartson. Mr. Whitehurst has specialized in partnership taxation and has advised Energy Transfer and its subsidiaries in his role as outside counsel since 2006. He has served as a member of the board of directors of USAC since April 2019.

Matthew S. Ramsey. Mr. Ramsey was appointed as a director of Energy Transfer's general partner in July 2012 and served as a director of ETO's general partner from November 2015 until its merger into Energy Transfer LP in April 2021. Mr. Ramsey has been the Chief Operating Officer or our general partner since October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P., and served as President and Chief Operating Officer of ETO's general partner from November 2015 until its merger into Energy Transfer LP in April 2021. Mr. Ramsey also served as President and Chief Operating Officer and Chairman of the board of directors of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Mr. Ramsey is also a director of Sunoco LP, having served as chairman of Sunoco LP's board since April 2015, and of USAC, having served on that board since April 2018. Mr. Ramsey previously served as President of RPM

Exploration, Ltd., a private oil and gas exploration partnership, and previously served as a director of RSP Permian, Inc. where he served on the audit and compensation committees. In addition to his work in the energy business, Mr. Ramsey serves on the board of directors of the National Association of Manufacturers and as a Trustee of the Southwestern Medical Foundation. He is the former Chairman of the University of Texas Chancellor's Council. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey was selected to serve based on vast experience in the oil and gas space and Energy Transfer believes that he provides valuable industry insight as a member of our Board of Directors.

Thomas P. Mason. Mr. Mason became Executive Vice President and General Counsel of the general partner of Energy Transfer in December 2015, and has served as the Executive Vice President, General Counsel and President - LNG since October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. In February 2021, Mr. Mason assumed leadership responsibility over the Partnership's new Alternative Energy Group, which focuses on the development of alternative energy projects aimed at continuing to reduce Energy Transfer's environmental footprint throughout its operations. Mr. Mason previously served as Senior Vice President, General Counsel and Secretary of ETO's general partner from April 2012 to December 2015, as Vice President, General Counsel and Secretary from June 2008 and as General Counsel and Secretary from February 2007. Prior to joining Energy Transfer, he was a partner in the Houston office of Vinson & Elkins. Mr. Mason has specialized in securities offerings and mergers and acquisitions for more than 25 years. Mr. Mason served as a director on the Board of Directors of the general partner of Sunoco Logistics Partners L.P. from October 2012 to April 2017 and as a director on the Board of Directors of PennTex Midstream Partners, LP's general partner from November 2016 to July 2017. Mr. Mason has also served as a director on the Board of Directors of USAC since April 2018.

John W. McReynolds. Mr. McReynolds is a director of Energy Transfer LP, having served in that capacity since August 2004. Mr. McReynolds previously served as the President of Energy Transfer LP from March 2005 until October 2018, at which time he became Special Advisor to the Partnership. Mr. McReynolds also previously served as our Chief Financial Officer from August 2005 to June 2013. Prior to becoming President of Energy Transfer LP, Mr. McReynolds was a partner in the international law firm of Hunton & Williams LLP for over 20 years. As a lawyer, he specialized in energy related finance, securities, partnerships, mergers and acquisitions, syndication and litigation matters, and served as an expert in numerous arbitration, litigation, and governmental proceedings, including as an expert in special projects for boards of directors of public companies. Mr. McReynolds was selected to serve in the indicated roles with Energy Transfer because of this extensive background and experience, as well as his many contacts and relationships in the industry.

A. Troy Sturrock. Mr. Sturrock is the Senior Vice President and Controller of our general partner having assumed that role in October 2018 following the merger of Energy Transfer Equity, L.P. and Energy Transfer Partners, L.P. He served as the Senior Vice President and Controller of the general partner of ETO from August 2016 until ETO's merger into Energy Transfer LP in April 2021, and previously served as Vice President and Controller of our general partner beginning in June 2015. Mr. Sturrock also served as a Senior Vice President of PennTex Midstream Partners, LP's general partner, from November 2016 until July 2017, and as its Controller and Principal Accounting Officer from January 2017 until July 2017. Mr. Sturrock previously served as Vice President and Controller of Regency GP LLC from February 2008, and in November 2010 was appointed as the principal accounting officer. Mr. Sturrock is a Certified Public Accountant.

Steven R. Anderson. Mr. Anderson was elected to the Board of Directors of our general partner in June 2018 and serves on the audit committee and compensation committee. Mr. Anderson began his career in the energy business in the early 1970's with Conoco in the Permian Basin area. He then spent some 25 years with ANR Pipeline and its successor, The Coastal Corporation, as a natural gas supply and midstream executive. He later was Vice President of Commercial Operations with Aquila Midstream and, upon the sale of that business to Energy Transfer in 2002, he became a part of the management team there. For the six years prior to his retirement from Energy Transfer in October 2009, he served as Vice President of Mergers and Acquisitions. Since that time, he has been involved in private investments and has served on the boards of directors of the St. John Health System and Saint Simeon's Episcopal Home in Tulsa, Oklahoma, as well as various other community and civic organizations. Mr. Anderson also served as a member of the board of directors of Sunoco Logistics Partners L.P. from October 2012 until April 2017. Mr. Anderson was selected to serve on our Board of Directors based on his experience in the midstream energy industry generally, and his knowledge of Energy Transfer's business specifically. Mr. Anderson also brings recent experience on audit and compensation committees of another publicly traded partnership.

Richard D. Brannon. Mr. Brannon was appointed to the Board of Directors of our general partner in March 2016 and has served as the Chairman of the audit committee since April 2016. Mr. Brannon is the CEO of CH4 Energy Six, LLC and Uinta Wax, LLC, both independent companies focused on horizontal oil and gas development. Mr. Brannon previously served on the board of directors of WildHorse Resource Development from its IPO in December 2016 until June 2018. Mr. Brannon also formerly served on the Board of Directors and as a member of the audit committee and compensation committee of Sunoco LP, Regency, OEC Compression and Cornerstone Natural Gas Corp. He has over 35 years of experience in the energy business, having started his career in 1981 with Texas Oil & Gas. The members of our general partner selected Mr. Brannon to serve as director based on his knowledge of the energy industry and his experience as a director and audit and compensation committee member for other public companies.

Ray C. Davis. Mr. Davis was appointed to the Board of Directors of the general partner of Energy Transfer LP in July 2018 and served on the Board of Directors of ETO from February 2018 until July 2018. From February 2013 until February 2018, Mr. Davis was an independent investor. He has also been a principal owner, and served as co-chairman of the board of directors, of the Texas Rangers major league baseball club since August 2010. Mr. Davis previously served on the Board of Directors of Energy Transfer LP, effective upon the closing of its IPO in February 2006 until his resignation in February 2013. Mr. Davis also served as ETO's Co-Chief Executive Officer from the combination of the midstream and transportation operations and the retail propane operations in January 2004 until his retirement from these positions in August 2007, and as the Co-Chairman of the Board of Directors of our general partner from January 2004 until June 2011. Mr. Davis also held various executive positions with Energy Transfer prior to 2004. Mr. Davis was selected to serve as director based on his over 40 years of business experience in the energy industry and his expertise in the Partnership's asset portfolio.

Michael K. Grimm. Mr. Grimm was appointed to the Board of Directors of our general partner in October 2018, and has served on the audit committee and compensation committee since that time. Prior to that time, Mr. Grimm served as a director of ETO's general partner beginning in December 2005, and served on the audit and compensation committee during that time. Mr. Grimm is one of the original founders of Rising Star Energy, L.L.C., a privately held upstream exploration and production company active in onshore continental United States, and served as its President and Chief Executive Officer from 1995 until 2006 when it was sold. Mr. Grimm is currently President of Rising Star Petroleum, LLC. Mr. Grimm was formerly Chairman of the Board of RSP Permian, Inc. (NYSE: RSPP) from January 2014 until June 2018. From November 2018 until it was sold in 2019, Mr. Grimm served on the Board of Directors of Anadarko Petroleum Corporation. Prior to the formation of Rising Star, Mr. Grimm was Vice President of Worldwide Exploration and Land for Placid Oil Company from 1990 to 1994. Prior to joining Placid Oil Company, Mr. Grimm was employed by Amoco Production Company for thirteen years where he held numerous positions throughout the exploration department in Houston, New Orleans and Chicago. Mr. Grimm has been an active member of the American Association of Professional Landmen, Dallas Wildcat Committee, Dallas Producers Club, and the All-American Wildcatters. He has a B.B.A. from the University of Texas at Austin. Mr. Grimm was selected to serve as a director because of his extensive experience in the energy industry and his service as a senior executive at several energy-related companies, in addition to his contacts in the industry gained through his involvement in energy-related organizations.

James R. (Rick) Perry. Mr. Perry was appointed to the Board of Directors of our general partner in January 2020. He formerly served as U.S. Secretary of Energy from March 2017 until December 2019. Prior to that, he served as the Governor of the State of Texas from 2000 until January 2015. Mr. Perry served as Lieutenant Governor of Texas from 1998 to 2000, and as Agriculture Commissioner from 1991 to 1998. Prior to 1991, he also served in the Texas House of Representatives. Mr. Perry previously served on the Board of Directors of ETO from February 2015 until December 2016. Mr. Perry was selected to serve as a director because of his vast experience as an executive in the highest office of state government. In addition, Mr. Perry has been involved in finance and budget planning processes throughout his career in government as a member of the Texas House Appropriations Committee, the Legislative Budget Board and as Governor.

Ray W. Washburne. Mr. Washburne was appointed to the Board of Directors of our general partner in April 2019. He is currently President and Chief Executive Officer of Charter Holdings, Inc., a Dallas-based investment company involved in real estate, restaurants and diversified financial investments. In addition, he currently serves on the President's Intelligence Advisory Board (PIAB). From August 2017 to February 2019, Mr. Washburne served as the President and Chief Executive Officer of the Overseas Private Investment Corporation (OPIC), the United States government's development finance institution. From 2000 to 2017, Mr. Washburne served on the board of directors of Veritex Holdings, Inc. (Nasdaq: VBTX), a Texas -based bank holding company that conducts banking activities through its subsidiary, Veritex Community Bank. He has also served as an adjunct professor at the Cox School of Business at Southern Methodist University. Mr. Washburne is also a member of the Republican Governors Association Executive Roundtable, the American Enterprise Institute, the Council on Foreign Relations, and is on the Advisory Board of the United States Southern Command. Mr. Washburne was selected to serve on the Board of Directors because of his expertise in international finance, his relationships in government, and his experience on the board of a publicly traded company.

Compensation of the General Partner

Our general partner does not receive any management fee or other compensation in connection with its management of the Partnership.

Delinquent Section 16(a) Reports

Section 16(a) of the Securities Exchange Act of 1934 requires the directors and executive officers of our general partner, as well as persons who own more than ten percent of the common units representing limited partnership interests in us, to file reports of ownership and changes of ownership on Forms 3, 4 and 5 with the SEC. The SEC regulations also require that copies of these Section 16(a) reports be furnished to us by such reporting persons. Based upon a review of copies of these reports, we believe that Thomas E. Long and Michael K. Grimm each had one delinquent report for 2021. All other applicable Section 16(a) reports were timely filed in 2021.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Named Executive Officers

Energy Transfer does not have officers or directors. Instead, we are managed by the board of directors of our General Partner, and the executive officers of our General Partner perform all of Energy Transfer's management functions. As a result, the executive officers of our General Partner are Energy Transfer's executive officers, and their compensation is administered by our General Partner. This Compensation Discussion and Analysis is, therefore, focused on the total compensation of the executive officers of our General Partner as set forth below. The persons we refer to in this discussion as our "named executive officers" are the following:

- Marshall S. (Mackie) McCrea, III, Co-Chief Executive Officer;
- Thomas E. Long, Co-Chief Executive Officer (and Chief Financial Officer until January 8, 2021);
- Bradford D. Whitehurst, Chief Financial Officer (effective January 8, 2021);
- Matthew S. Ramsey, Chief Operating Officer;
- Thomas P. Mason, Executive Vice President, General Counsel and President — LNG; and
- A. Troy Sturrock, Senior Vice President and Controller.

Our Philosophy for Compensation of Executives

In general, our General Partner's philosophy for executive compensation is based on the premise that a significant portion of each executive's compensation should be incentive-based or "at-risk" compensation and that executives' total compensation levels should be highly competitive in the marketplace for executive talent and abilities. Our General Partner seeks a total compensation program for its executive officers, including the named executive officers, that provides for a slightly below the median market annual base compensation (i.e., approximately the 30th to 40th percentile of market) but incentive-based compensation composed of a combination of compensation vehicles to reward both short- and long-term performance that are both targeted to pay out at approximately the top-quartile of market. Our General Partner believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider the achievement of the Partnership's financial performance objectives for a fiscal year set at the beginning of such fiscal year and the individual contributions of its executive officers, including the named executive officers, to the success of the Partnership and the achievement of the annual financial performance objectives and (ii) the annual grant of time-based restricted unit, phantom unit awards or cash restricted unit awards under the Partnership's equity incentive plan(s) or the equity incentive programs of Sunoco LP, as applicable based on the allocation of executive officers awards, including awards to the named executive officers, which awards are intended to provide a longer term incentive and retention value to its key employees to focus their efforts on increasing the market price of its publicly traded units and to increase the cash distribution the Partnership and/or the other affiliated partnerships pay to their respective unitholders.

The Partnership has historically granted restricted unit and/or phantom unit awards ("RSUs") that vest, based generally upon continued employment, at a rate of 60% after the third year of service and the remaining 40% after the fifth year of service. In 2020 and 2021, Energy Transfer also granted cash restricted units ("CRSUs") that vest, based generally upon continued employment, at a rate of 1/3 annually over a three-year period. For 2020, the awards to employees were generally split equally between RSUs and CRSUs; for 2021, the awards were generally split based on 75% RSUs and 25% CRSUs. The Partnership believes that these equity-based incentive arrangements are important in attracting and retaining executive officers and key employees as well as motivating these individuals to achieve stated business objectives. The equity-based compensation reflects the importance our General Partner places on aligning the interests of its named executive officers with those of Unitholders. While the Partnership utilizes time-based forms of equity awards, the grant date valuation utilizes a modified total unitholder return ("TUR") performance as measured against the average return of Energy Transfer's identified peer group over defined time periods. The modified TUR is designed to create a recognition of a performance adjustment to the equity awards based on the prior periods measured to add an element of performance impact in setting grant date value even though the RSUs and CRSUs themselves are a time-vested vehicle.

As discussed below, our compensation committee and/or the compensation committee of the general partner of Sunoco LP, as applicable, all in consultation with our General Partner, are responsible for the compensation policies and compensation level of our executive officers, including the named executive officers of our General Partner. In this discussion, we refer to our compensation committee as the "Energy Transfer Compensation Committee."

For a more detailed description of the compensation to the Partnership's named executive officers, please see "– Compensation Tables" below.

Distributions to Our General Partner

Our General Partner is majority-owned by Mr. Kelcy Warren. We pay quarterly distributions to our General Partner in accordance with our partnership agreement with respect to its ownership of its general partner interest as specified in our partnership agreement. The cash distributions we make to our General Partner bear no relationship to the level or components of compensation of our General Partner's executive officers. Distributions to our General Partner are described in detail in Note 8 to our consolidated financial statements. Our named executive officers also own directly and indirectly certain of our limited partner interests and, accordingly, receive quarterly distributions. Such per-unit distributions equal the per-unit distributions made to all our limited partners and bear no relationship to the level of compensation of the named executive officers or the services they perform as employees.

For a more detailed description of the compensation of our named executive officers, please see "– Compensation Tables" below.

Compensation Philosophy

Our compensation programs are structured to achieve the following:

- reward executives with an industry-competitive total compensation package of base salaries and significant incentive opportunities yielding a total compensation package approaching the top-quartile of the market;
- attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships or other peer companies of similar size and in similar lines of business;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based, or "at-risk," compensation; and
- reward individual performance.

Components of Executive Compensation

For the year ended December 31, 2021, the compensation paid to our named executive officers consisted of the following components:

- annual base salary;
- non-equity incentive plan compensation consisting solely of discretionary cash bonuses;
- time-vested RSUs and CRSUs under the equity incentive plan(s);
- payment of distribution equivalent rights ("DERs") on unvested time-based RSUs under our equity incentive plan;
- vesting of previously issued time-based RSUs issued pursuant to our equity incentive plans or the equity incentive plans(s) of affiliates; and
- 401(k) plan employer contributions.

Methodology

The Energy Transfer Compensation Committee considers relevant data available to it to assess our competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our executive officers, including the named executive officers. The Energy Transfer Compensation Committee also considers individual performance, levels of responsibility, skills and experience.

Periodically, the Energy Transfer Compensation Committee engages a third-party independent compensation consultant to provide a full market competitive compensation analysis for compensation levels at peer companies in order to assist in the determination of compensation levels for our executive officers, including the named executive officers. Most recently, Meridian Compensation Partners, LLC ("Meridian") was engaged to evaluate the market competitiveness of total compensation levels of a number of officers of the Partnership to provide market information with respect to compensation of those executives during the year ended December 31, 2021. In particular, the review by Meridian was designed to (i) evaluate the market competitiveness of total compensation levels for certain members of senior management, including our named executive officers; (ii) assist in the determination of appropriate compensation levels for our senior management, including the named executive officers; and (iii) confirm that our compensation programs were yielding compensation packages consistent with our overall compensation philosophy.

In conducting its review, Meridian assisted in the development of the final "peer group" of leading companies in the energy industry that most closely reflect the profile of Energy Transfer. The final "peer group" consisted of the core group of peers (i.e. the eight most similar peers in terms of business, revenues, assets and market value as well as competition for talent at the senior management level) and a group of expanded reference companies composed of a broader group of oil and gas companies, including additional integrated, upstream and midstream comparators whose data provided additional market context. As part of the evaluation conducted by Meridian , a determination was made to focus the analysis largely on the core energy industry peers. This decision was based on a determination that the core peer group provided a more than sufficient amount of comparative data to consider and evaluate total compensation. This focus allowed Meridian to report on this specific core peer data comparing the levels of annual base salary, annual short-term cash bonus and long-term equity incentive awards at industry peer group companies with those of the named executive officers to ensure that compensation of the named executive officers is both consistent with the compensation philosophy and competitive with the compensation for executive officers of these other companies, while at the same time considering whether the context provided by the expanded group offered additional information that should be considered by the Compensation Committee. The core identified companies were:

Energy Peer Group:

• Conoco Phillips	• Marathon Petroleum Corporation
• Enterprise Products Partners, L.P.	• Kinder Morgan, Inc.
• Plains All American Pipeline, L.P.	• The Williams Companies, Inc.
• Valero Energy Corporation	• Phillips 66

The compensation analysis provided by Meridian in 2021 covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term incentive awards for the senior executives. In preparing the review materials, Meridian utilized generally accepted compensation principles and gathered data from public disclosures of peer companies, including Form 10-K and proxy data and published survey data from multiple sources that are relevant to Energy Transfer's core peer group, industry, financial size and operational breadth. The Meridian review process also included significant engagement with management to fully understand job scope, responsibilities and roles of each of the executive officers, which discussions allow Meridian the ability to completely evaluate specific aspects of an executive officer's position to allow for more accurate comparisons.

Following Meridian's 2021 review, the Energy Transfer Compensation Committee reviewed the information provided, including Meridian's specific conclusions and recommended considerations for all compensation going forward. The Energy Transfer Compensation Committee considered and reviewed the results of the study performed by Meridian to determine if the results indicated that the compensation programs were yielding a competitive total compensation model prioritizing incentive-based compensation and rewarding achievement of short and long-term performance objectives and considered Meridian's conclusions and recommendations. While Meridian found that the Partnership is achieving its stated objectives with respect to the "at-risk" approach, they also found that certain adjustments could be considered moving forward to allow the Partnership to continue to achieve its targeted percentiles on base compensation and incentive compensation (short and long-term). Certain of Meridian's suggested adjustments as part of the review were implemented and others were determined to require additional review and consideration.

In addition to the information received as part of Meridian's review, the Energy Transfer Compensation Committee also utilizes information obtained from other sources in its determination of compensation levels for our named executive officers, such as annual third party surveys, although third party survey data is not used by the Energy Transfer Compensation Committee to benchmark the amount of total compensation or any specific element of compensation for the named executive officers.

Base Salary. Base salary is designed to provide for a competitive fixed level of pay that attracts and retains executive officers and compensates them for their level of responsibility and sustained individual performance (including experience, scope of responsibility and results achieved). The salaries of the named executive officers are reviewed on an annual basis. As discussed above, the base salaries of our named executive officers are targeted to yield an annual base salary slightly below the median level of market (i.e. approximately the 30th to 40th percentile of market) and are determined by the Energy Transfer Compensation Committee after taking into account the recommendations of Mr. Warren.

During the merit review process, the Energy Transfer Compensation Committee considers the recommendations of Mr. Warren, any relevant compensation study data (with the data aged as appropriate) and the merit increase pool set for all employees of the Partnership and/or its employing affiliates. During 2021, the Energy Transfer Compensation Committee approved a 3.5% increase to the base salary of Mr. McCrea to $1,345,500 from the prior level of $1,300,000; a 3.5% increase to the base salary of Mr. Long to $1,345,500 from the previous level of $1,300,000; a 3.5% increase to the base salary of Mr. Whitehurst to $615,825 from the previous level of $595,000; a 3.5% increase to the base salary of Mr. Ramsey to $720,978 from the previous level of $696,598; and a 3.5% increase to the base salary of Mr. Mason to $653,495 from the previous level of $631,396. During 2021, Mr. Sturrock also initially received a 3.5% increase to a base salary of $279,765 from the previous level of $269,110 and then subsequently received an additional base salary increase to $310,000 in connection with his compensation review as part of the Meridian study.

In connection with their promotions to Co-Chief Executive Officer effective January 1, 2021, the Energy Transfer Compensation Committee had previously approved increases in the annual base salaries of Messrs. McCrea and Long to $1,300,000. In connection with his promotion to Chief Financial Officer effective January 8, 2021, the Energy Transfer Compensation Committee approved an increase in the annual base salary of Mr. Whitehurst to $595,000 from his previous level of $559,676.

Annual Bonus. In addition to base salary, the Energy Transfer Compensation Committee makes determinations whether to make discretionary annual cash bonus awards to executives, including our named executive officers, following the end of the year under the Bonus Plan.

The Bonus Plan is a discretionary annual cash bonus plan available to all employees, including the named executive officers. The purpose of the Bonus Plan is to reward employees for contributions towards the Partnership’s business goals and to aid in motivating employees. The Bonus Plan is administered by the Energy Transfer Compensation Committee and the Energy Transfer Compensation Committee has the authority to establish and interpret the rules and regulations relating to the Bonus Plan, to select participants, to determine and approve the size of any actual award amount, to make all determinations, including factual determinations, under the Bonus Plan, and to take all other actions necessary or appropriate for the proper administration of the Bonus Plan.

For each calendar year or any other period designated by the Energy Transfer Compensation Committee (the “Performance Period”), the Energy Transfer Compensation Committee will evaluate and determine an overall funded cash bonus pool based on achievement of (i) an internal Adjusted EBITDA target (“Adjusted EBITDA Target”), (ii) an internal distributable cash flow target (“DCF Target”) and (iii) performance of each department compared to the applicable departmental budget (“Departmental Budget Target”). For purposes of the Adjusted EBITDA Target and the DCF Target established in the Bonus Plan, the measures of Adjusted EBITDA and Distributable Cash Flow are calculated using the same definitions as used in the Partnership’s publicly reported financial information, including the Partnership’s earnings press releases, investor presentations, and annual and quarterly filings on Forms 10-K and 10-Q. The performance criteria are weighted 60% on the achievement of the Adjusted EBITDA Target, 20% on the achievement of the DCF Target and 20% on the achievement of the Departmental Budget Target (collectively, “Budget Targets”). The total amount of cash to be allocated to the funded bonus pool will range from 0% to 120% for each of the budgeted DCF Target and Adjusted EBITDA Target and will range from 0% to 100% of the Departmental Budget Target. The maximum funding of the bonus pool is 116% of the total pool target and to achieve such funding each of the Adjusted EBITDA and the DCF Target must achieve 120% funding and the Department Budget target must achieve its 100% target. While the funded bonus pool will reflect an aggregation of performance under each target, in the event performance under the Adjusted EBITDA Target is below 80% of its target, no bonus pool will be funded. If the bonus pool is funded, a participant may earn a cash award for the Performance Period based upon the level of attainment of the Budget Targets and his or her individual performance. Awards are paid in cash as soon as practicable after the end of the Performance Period but in no event later than two and one-half months after the end of the Performance Period.

While the achievement of the Budget Targets sets a bonus pool under the Bonus Plan, actual bonus awards are discretionary. These discretionary bonuses, if awarded, are intended to reward our named executive officers for the achievement of the Budget Targets during the Performance Period in light of the contribution of each individual to our profitability and success during such year. The Energy Transfer Compensation Committee also considers the recommendation of Mr. Warren in determining the specific annual cash bonus amounts for each of the named executive officers. The Energy Transfer Compensation Committee does not establish its own financial performance objectives in advance for purposes of determining whether to approve any annual bonuses, and it does not utilize any formulaic approach to determine annual bonuses.

In connection with his promotion to Co-Chief Executive Officer effective January 1, 2021, the Energy Transfer Compensation Committee established a bonus pool target for Mr. Long of 160% of his annual base earnings from his previous bonus target, which had been 130% of his annual base earnings. For Mr. McCrea, his 2021 bonus pool target was 160%, consistent with his 2020 target. For 2021, the Energy Transfer Compensation Committee approved short-term annual cash bonus pool targets for Messrs. Whitehurst, Ramsey and Mason of 130% of their respective annual base earnings, consistent with their previous targets. Mr. Sturrock’s 2021 short-term annual cash bonus pool target was 100% of his annual base earnings.

In respect of a 2020 bonus pool funding, executive management recommended to the Compensation Committee that the bonus be paid at a 0% payout. This recommendation was made in consideration of a number of factors including (i) the challenging conditions within the industry, specifically the impacts of the COVID-19 pandemic on Energy Transfer and the global energy market; (ii) the impact of market conditions on current capital projects and certain planned future capital growth projects; and (iii) the reduction of quarterly cash distributions payable to Energy Transfer common unit holders by 50% in 2020. After considering quantitative and qualitative factors, including performance level achieved, the Compensation Committee exercised its negative discretion to award a 0% payout of the non-equity incentive bonus.

Understanding the challenges of the 2020 performance year and the anticipation of the Partnership significantly exceeding its Adjusted EBITDA and DCF targets, the Energy Transfer Compensation Committee took action in the first half of 2021 to approve an accrual to 150% of the annual bonus pool target and authorized the payment of 25% of the accrued pool in March and an additional 25% in July. The Compensation Committee also used its discretion under the Bonus Plan to exceed the maximum pool target of 116% to the 150% accrual.

In February 2022, the Energy Transfer Compensation Committee certified 2021 performance results under the Bonus Plan and authorized payment of the remaining 100% of the 150% accrual approved earlier in the year. This bonus payout reflected the achievement of 127% of the Adjusted EBITDA Target, 150% of the DCF Target and 97% of, or $23 million under, the Department Budget Target. Based on the approved results, the Energy Transfer Compensation Committee approved a cash bonus relating to the 2021 calendar year to Messrs. McCrea, Long, Whitehurst, Ramsey, Mason and Sturrock in the amounts of $3,156,400, $3,156,400, $1,174,000, $1,374,000, $1,252,000 and $415,575, respectively. These amounts include the pre-payments in March and June of Messrs. McCrea, Long, Whitehurst, Ramsey, Mason and Sturrock in the amounts of $1,040,000, $1,040,000, $387,000, $453,000, $417,000 and $135,275, respectively.

Equity Awards. Energy Transfer maintains and operates (i) the Second Amended and Restated Energy Transfer LP 2008 Incentive Plan (the "2008 Incentive Plan"); (ii) the Energy Transfer LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"); the (iii) Energy Transfer LP 2015 Long-Term Incentive Plan (the "2015 Plan"); (iv) the Amended and Restated Energy Transfer LP Long-Term Incentive Plan (the "Energy Transfer Plan," together with the 2008 Incentive Plan, the 2011 Incentive Plan and the 2015 Plan, the "Energy Transfer Incentive Plans"). The Energy Transfer Incentive Plans authorize the Energy Transfer Compensation Committee, in its discretion, to grant awards, as applicable, under each respective plan of RSUs upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by the Energy Transfer Incentive Plans. Energy Transfer has generally used time-vested restricted units and/or phantom units as the vehicle for its annual equity awards to eligible employees, including the named executive officers.

In addition, in 2020, Energy Transfer adopted the Energy Transfer LP Long-Term Cash Restricted Unit Plan (the "CRU Plan"). The CRU Plan authorizes the Energy Transfer Compensation Committee, in its discretion, to grant awards, as applicable, of CRSUs, upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by the CRU Plan. Like awards from the Energy Transfer Incentive Plans, awards from the CRU Plan will be used to incentivize and reward eligible employees over a long-term basis, and the CRU Plan is included for purposes of these discussions as an "Energy Transfer Incentive Plan."

In connection with their promotions to Co-Chief Executive Officer effective January 1, 2021, the Energy Transfer Compensation Committee established long-term incentive targets for Messrs. McCrea and Long of 900% of their annual base earnings. For Mr. McCrea, his 2021 long-term incentive target was consistent with his 2020 target; for Mr. Long, his 2021 long-term incentive target was an increase from his previous bonus target, which had been 500% of his annual base earnings. In connection with his promotion to Chief Financial Officer effective January 8, 2021, the Energy Transfer Compensation Committee established the long-term incentive target for Mr. Whitehurst of 500% of his annual base earnings. For 2021, the Energy Transfer Compensation Committee approved long-term incentive targets for Messrs. Ramsey, Mason and Sturrock of 500%, 500% and 200%, respectively, of their respective annual base earnings, consistent with their previous targets.

The annual long-term incentive targets are used as the basis to determine the target number of units to be awarded to the eligible participant, including the named executive officers. A multiple of base salary is used to set the pool target, that number is then divided by a weighted average price determined by considering Energy Transfer's modified total unitholder return ("TUR") performance as measured against the average return of Energy Transfer's identified peer group over defined time periods. The modified TUR is designed to create a recognition of a performance adjustment to the equity awards based on the prior periods measured to add an element of performance impact in setting grant date value even though the RSUs and CRSUs themselves are time-vested vehicles. For purposes of establishing an initial price, Energy Transfer utilizes a 60 trading-day trailing weighted average price of Energy Transfer common units prior to October 29, 2021. This average trading price is then subject to adjustment when Energy Transfer's TUR is more than 5% greater or less than that of its identified peer group. If the TUR analysis yields a result that is within 5% percent of its identified peer group, the Energy Transfer Compensation Committee will simply use the 60 trading day trailing weighted average price divided by the applicable salary multiple to establish a target pool for each eligible participant, including the named executive officers. If Energy Transfer's TUR is outside of the 5% deviation, the 60 trading day trailing weighted average will be adjusted up or down to a maximum of 15% from the trailing weighted average price based on Energy Transfer's performance as compared to the identified group. For 2021, the peer group included the following:

• Enterprise Products Partners, L.P.	• Kinder Morgan, Inc.
• The Williams Companies, Inc.	• Plains All American Pipeline, L.P.
• Phillips 66 Partners LP	• MPLX LP

For 2021, the Partnership's TUR outperformed the identified peer group by approximately 25% based on the average of the identified three comparison periods: (i) year-to-date 2021, (ii) trailing twelve months, and (iii) full-year 2020. Consequently, the 2021 long-term incentive base price was decreased to increase the total available restricted pool by the maximum of 15%.

In December 2021, the Energy Transfer Compensation Committee in consultation with Mr. Warren approved grants of RSUs to Messrs. McCrea, Long, Whitehurst, Mason and Sturrock of 1,121,250 units, 1,121,250 units, 228,000 units, 300,300 units, and 57,375 units, respectively. The Energy Transfer Compensation Committee also approved grants of CRSUs to Messrs. McCrea, Long, Whitehurst, Mason and Sturrock of 373,750 units, 373,750 units, 76,000 units, 100,100 units and 19,125 units, respectively.

The RSUs granted in 2021 provide for incremental vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year. Vesting of the awards is generally subject to continued employment through each specified vesting date. The RSU awards entitle the recipients to receive, with respect to each Energy Transfer unit subject to such award that has not either vested or been forfeited, a DER cash payment promptly following each such distribution by Energy Transfer to its common unitholders.

The CRSUs granted in 2021 provide for incremental vesting over a three-year period, with 1/3 vesting at the end of each year. Each CRSU entitles the award recipient to receive cash equal to the market value of one Energy Transfer common unit upon vesting. The CRSU do not include rights to DER cash payments.

In approving the grant of such RSUs and CRSUs, including to the named executive officers, the Energy Transfer Compensation Committee considered several factors, including the long-term objective of retaining such individuals as key drivers of Energy Transfer's future success, the existing level of equity ownership of such individuals and the previous awards to such individuals of equity awards subject to vesting. Vesting of the 2021 awards would accelerate in the event of the death or disability of the recipient, including the named executive officers, or in the event of a change in control of Energy Transfer as that term is defined under the Energy Transfer Incentive Plans.

Mr. Ramsey had announced his intentions to retire in April 2022 and, as such, did not receive an award of RSUs and CRSUs in December 2021.

For 2020, Mr. McCrea did not receive an award of CRSUs; instead, he received a special one-time time vested cash award of $5,000,000 payable as follows:

- $1,800,000 on December 31, 2020;
- $1,600,000 on July 1, 2021; and
- $1,600,000 on December 5, 2022.

This amount is intended to approximate 50% of Mr. McCrea's targeted annual equity award and replace the award of CRSUs made to other named executive officers. During 2021, Mr. McCrea received payment of $1,600,000 in July. The last payment of $1,600,000 will be made during 2022.

As discussed below under "Potential Payments Upon a Termination or Change of Control," all outstanding equity awards would automatically accelerate upon a change in control event, which means vesting automatically accelerates upon a change of control irrespective of whether the officer is terminated. In addition, the award agreements for the RSUs and CRSUs awarded in 2020, as well as other awards outstanding held by Partnership employees, including the named executive officers, also include certain acceleration provisions upon retirement with the ability to accelerate 40% of outstanding unvested awards under the Energy Transfer Incentive Plans at age 65 and 50% at age 68. These acceleration provisions require that the participant have not less than five (5) years of employment service to the Partnership or an affiliate and require a six (6) month delay in the vesting after retirement pursuant to the requirements of Section 409(A) of the Code.

We believe that permitting the accelerated vesting of equity awards upon a change in control creates an important retention tool for us by enabling employees to realize value from these awards in the event that we undergo a change in control transaction. In addition, we believe permitting acceleration of vesting upon a change in control creates a sense of stability in the course of transactions that could create uncertainty regarding their future employment and encourage these officers to remain focused on their job responsibilities.

Affiliate and Subsidiary Equity Awards. In addition to his role as an officer for Energy Transfer during 2021, Mr. Whitehurst has certain responsibilities for Sunoco LP, including a leadership role for certain shared service functions.

The Sunoco LP Compensation Committee in December 2021 approved a grant of RSUs to Mr. Whitehurst of 16,100 restricted units, under the 2018 Sunoco LP Plan. The terms and conditions of the restricted unit to Mr. Whitehurst under the 2018 Sunoco LP Plan provided for vesting over a five-year period, with 60% vesting at the end of the third year and the remaining 40% vesting at the end of the fifth year, subject generally to continued employment through each specified vesting date. All of the award would be accelerated in the event of his death or disability, or upon a change in control. The retirement acceleration provisions for this award under the 2018 Sunoco LP Plan are the same as the retirement acceleration provisions under Energy Transfer Incentive Plans with the ability to accelerate at retirement 40% of outstanding unvested awards at age 65 and 50% at age 68.

Mr. Ramsey previously received a portion of his total equity award from Sunoco LP. For 2021, the Sunoco LP Compensation Committee did not make an award to Mr. Ramsey as a result of his impending retirement in April 2022.

Special One-Time Awards to Co-Chief Executive Officers. In recognition of their assumption of their new roles as Co-Chief Executive Officers effective January 1, 2021, the Energy Transfer Compensation Committee approved certain one-time awards to Messrs. McCrea and Long.

Mr. McCrea received a special one-time award of 241,815 RSUs under the Energy Transfer Incentive Plans and a special cash payment of $1,625,000 in connection with his appointment as Co-Chief Executive Officer, effective January 1, 2021.

Mr. Long received a special one-time award of 483,630 RSUs under the Energy Transfer Incentive Plans in connection with his appointment as Co-Chief Executive Officer, effective January 1, 2021.

The RSU awards to Messrs. McCrea and Long were made at the same grant date valuation and vesting schedules used for the annual equity awards described above under "—Equity Awards" section above. These awards were approved by the Energy Transfer Compensation Committee on December 30, 2020 to be effective immediately upon Messrs. McCrea and Long assuming their new roles on January 1, 2021 and are reflected as compensation in 2021 in the Compensation Tables section below.

Unit Ownership Guidelines. In 2021, the Board of Directors of our General Partner adopted an update to the Executive Unit Ownership Guidelines (the "Guidelines"), which sets forth minimum ownership guidelines applicable to certain executives of Energy Transfer with respect to Energy Transfer and Sunoco LP common units, as applicable. The applicable Guidelines are denominated as a multiple of base salary, and the amount of common units required to be owned increases with the level of responsibility. Under these Guidelines, (i) the Chief Executive Officer /Co-Chief Executive Officer(s) are expected to own common units having a minimum value of six times base salary; (ii) the Chief Operating Officer, the Chief Financial Officer, the General Counsel and other C-Suite executives expected to own common units having a minimum value of four times their respective base salary; and (iii) Senior Vice Presidents are expected to own common units having a minimum value of two times their respective base salary. In addition to the named executive officers, these Guidelines also apply to other covered executives, which executives are expected to own either directly or indirectly in accordance with the terms of the Guidelines, common units having minimum values ranging from two to four times their respective base salary.

The Energy Transfer Compensation Committee believes that the ownership of Energy Transfer and/or Sunoco LP common units, as reflected in these Guidelines, is an important means of tying the financial risks and rewards for its executives to Energy Transfer's total unitholder return, aligning the interests of such executives with those of Unitholders, and promoting Energy Transfer's interest in good corporate governance.

Covered executives are generally required to achieve their ownership level within five years of becoming subject to the Guidelines. As of December 31, 2021, all of the named executive officers were compliant with the level required of the Guidelines as of that date.

Covered executives may satisfy the Guidelines through direct ownership of Energy Transfer and/or Sunoco LP common units or indirect ownership by certain immediate family members. Direct or indirect ownership of Energy Transfer and/or Sunoco LP common units shall count on a one-to-one ratio for purposes of satisfying minimum ownership requirements; however, unvested unit awards may not be used to satisfy the minimum ownership requirements.

Executive officers, including the named executive officers, who have not yet met their respective guideline must retain and hold all common units (less common units sold to cover the executive's applicable taxes and withholding obligation) received in connection with long-term incentive awards. Once the required ownership level is achieved, ownership of the required common units must be maintained for as long as the covered executive is subject to the Guidelines. However, those individuals who have met or exceeded their applicable ownership level guideline may dispose of the common units in a manner consistent with applicable laws, rules and regulations, including regulations of the SEC and our internal policies, but only to the extent that such individual's remaining ownership of common units would continue to exceed the applicable ownership level.

Qualified Retirement Plan Benefits. The Energy Transfer LP 401(k) Plan (the "Energy Transfer 401(k) Plan") is a defined contribution 401(k) plan, which covers substantially all of our employees, including the named executive officers. Employees may elect to defer up to 100% of their eligible compensation after applicable taxes, as limited under the Internal Revenue Code. We make a matching contribution that is not less than the aggregate amount of matching contributions that would be credited to a participant's account based on a rate of match equal to 100% of each participant's elective deferrals up to 5% of covered compensation. During 2020, in response to challenging conditions within the industry, including impacts of the COVID-19 pandemic, Energy Transfer suspended its 401(k) matching contribution from July 1, 2020 through December 31, 2020. The amounts deferred by the participant are fully vested at all times, and the amounts contributed by the Partnership become vested based on years of service. We provide this benefit as a means to incentivize employees and provide them with an opportunity to save for their retirement.

The Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with a base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service. As with the 401(k) matching contributions, Energy Transfer suspended the profit sharing contribution from July 1, 2020 through December 31, 2020; however, the profit sharing contributions were reinstated for the full year 2021.

Health and Welfare Benefits. All full-time employees, including our named executive officers may participate in the Partnership's health and welfare benefit programs including medical, dental, vision, flexible spending, life insurance and disability insurance.

Termination Benefits. Our named executive officers do not have any employment agreements that call for payments of termination or severance benefits or that provide for any payments in the event of a change in control of our General Partner; however, the award agreement to the named executive officers under the Energy Transfer Incentive Plans, the 2018 Sunoco LP Plan and the Sunoco LP 2012 Long-Term Incentive Plan (the "2012 Sunoco LP Plan") provide for immediate vesting of all unvested restricted unit awards in the event of a (i) change of control, as defined in the plan; (ii) death or (iii) disability, as defined in the applicable plan. Please refer to "Compensation Tables - Potential Payments Upon a Termination or Change of Control" for additional information.

In addition, in 2021 the Partnership has also adopted the Partnership Severance Plan and Summary Plan Description effective as of December 1, 2021, (the "Severance Plan"), which provides for payment of certain severance benefits in the event of Qualifying Termination (as that term is defined in the Severance Plan). In general, the Severance Plan provides payment of two weeks of annual base salary for each year or partial year of employment service up to a maximum of fifty-two weeks or one year of annual base salary (with a minimum of four weeks of annual base salary) and up to three months of continued group health insurance coverage. The Severance Plan also provides that we may determine to pay benefits in addition to those provided under the Severance Plan based on special circumstances, which additional benefits shall be unique and non-precedent setting. The Severance Plan is available to all salaried employees on a nondiscriminatory basis; therefore, amounts that would be payable to our named executive officers upon a Qualified Termination have been excluded from "Compensation Tables – Potential Payments Upon a Termination or Change of Control" below.

Energy Transfer LP Non-Qualified Deferred Compensation Plan (the "Energy Transfer NQDC Plan") is a deferred compensation plan, which permits eligible highly compensated employees to defer a portion of their salary, bonus, and/or quarterly non-vested phantom unit distribution equivalent income until retirement, termination of employment or other designated distribution event. Each year under the Energy Transfer NQDC Plan, eligible employees are permitted to make an irrevocable election to defer up to 50% of their annual base salary, 50% of their quarterly non-vested phantom unit distribution income, and/or 50% of their discretionary performance bonus compensation during the following year. Pursuant to the Energy Transfer NQDC Plan, Energy Transfer may make annual discretionary matching contributions to participants' accounts; however, Energy Transfer has not made any discretionary contributions to participants' accounts and currently has no plans to make any discretionary contributions to participants' accounts. All amounts credited under the Energy Transfer NQDC Plan (other than discretionary credits) are immediately 100% vested. Participant accounts are credited with deemed earnings or losses based on hypothetical investment fund choices made by the participants among available funds.

Participants may elect to have their account balances distributed in one lump sum payment or in annual installments over a period of three or five years upon retirement, and in a lump sum upon other termination events. Participants may also elect to take lump-sum in-service withdrawals five years or longer in the future, and such scheduled in-service withdrawals may be further deferred prior to the withdrawal date. Upon a change in control (as defined in the Energy Transfer NQDC Plan) of Energy Transfer, all Energy Transfer NQDC Plan accounts are immediately vested in full. However, distributions are not accelerated and, instead, are made in accordance with the Energy Transfer NQDC Plan’s normal distribution provisions unless a participant has elected to receive a change of control distribution pursuant to his deferral agreement. None of our named executive officers currently participate in this plan.

Risk Assessment Related to our Compensation Structure. We believe that the compensation plans and programs for our named executive officers, as well as our other employees, are appropriately structured and are not reasonably likely to result in material risk to us. We believe these compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could harm our value or reward poor judgment. We also believe we have allocated compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of a portion of our operations. Our subsidiaries generally determine whether, and to what extent, their respective named executive officers receive a cash bonus based on achievement of specified financial performance objectives as well as the individual contributions of our named executive officers to the Partnership’s success. We and our subsidiaries use restricted units and phantom units rather than unit options for equity awards because restricted units and phantom units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options “in-the-money.” Finally, the time-based vesting over five years for our long-term incentive awards ensures that the interests of employees align with those of Unitholders and our subsidiaries’ unitholders for our long-term performance.

Tax and Accounting Implications of Equity-Based Compensation Arrangements

Deductibility of Executive Compensation

We are a limited partnership and not a corporation for United States federal income tax purposes. Therefore, we believe that the compensation paid to the named executive officers is not subject to the deduction limitations under Section 162(m) of the Internal Revenue Code and therefore is generally fully deductible for United States federal income tax purposes.

Accounting for Non-Cash Compensation

For non-cash compensation arrangements, we record compensation expense over the vesting period of the awards, as discussed further in Note 2 and Note 9 to our consolidated financial statements.

Compensation Committee Interlocks and Insider Participation

Mr. Steven R. Anderson, Mr. Michael K. Grimm and Mr. Ray W. Washburne are the only members of the Energy Transfer Compensation Committee. During 2021, no member of the Energy Transfer Compensation Committee was an officer or employee of us or any of our subsidiaries or served as an officer of any company with respect to which any of our executive officers served on such company’s board of directors. Neither Mr. Grimm nor Mr. Washburne is a former employee of ours or any of our subsidiaries. Mr. Anderson was previously an employee of the Partnership until his retirement in October 2009, as discussed in his biographical information included in “Item 10. Directors, Executive Officers and Corporate Governance.”

Report of Compensation Committee

The board of directors of our General Partner has reviewed and discussed the section entitled "Compensation Discussion and Analysis" with the management of Energy Transfer. Based on this review and discussion, we have recommended that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

The Compensation Committee of the
Board of Directors of LE GP, LLC,
general partner of Energy Transfer LP

Steven R. Anderson
Michael K. Grimm
Ray W. Washburne

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this annual report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

Compensation Tables

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Equity Awards [(1)] ($)	Non-Equity Incentive Plan Compensation[(2)] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation [(3)] ($)	Total ($)
Thomas E. Long	2021	$1,322,750	$ —	$ 15,224,039	$ 3,156,400	$ —	$ 27,014	$ 19,730,203
Co-Chief Executive Officer	2020	623,077	—	2,781,255	—	—	21,603	3,425,935
	2019	570,869	—	3,352,795	900,000	—	21,544	4,845,208
Marshall S. (Mackie) McCrea, III [(4)]	2021	1,322,750	3,225,000	13,734,458	3,156,400	—	22,044	21,460,652
Co-Chief Executive Officer	2020	1,157,423	1,800,000	4,597,516	—	—	18,045	7,572,984
	2019	1,094,260	—	8,734,720	1,750,817	—	21,544	11,601,341
Bradford D. Whitehurst	2021	605,413	—	3,102,694	1,174,000	—	15,760	4,897,867
Chief Financial Officer	2020	581,202	—	2,596,850	—	—	16,224	3,194,276
Matthew S. Ramsey	2021	708,788	—	—	1,374,000	—	21,167	2,103,955
Chief Operating Officer	2020	723,390	—	3,229,770	—	—	22,097	3,975,257
	2019	683,913	—	3,123,186	889,100	—	19,544	4,715,743
Thomas P. Mason	2021	642,445	—	3,279,498	1,252,000	—	22,706	5,196,649
Executive Vice President, General Counsel and President – LNG	2020	655,680	—	2,609,350	—	—	20,007	3,285,037
	2019	619,899	—	2,749,440	805,900	—	19,544	4,194,783
A. Troy Sturrock	2021	280,247	—	626,578	415,575	—	17,035	1,339,435
Senior Vice President and Controller								

(1) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718, disregarding any estimates for forfeitures. For Messrs. Whitehurst amounts include equity awards of our subsidiary, Sunoco LP, as reflected in the "Grants of Plan-Based Awards Table." See Note 9 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" for additional assumptions underlying the value of the equity awards. Although the CRSU awards may only be settled in cash, they are based upon the value of Energy Transfer common units and are accounted for as equity awards within these compensation tables.

(2) Energy Transfer maintains the Bonus Plan which provides for discretionary bonuses. Awards of discretionary bonuses are tied to achievement of targeted performance objectives and described in the Compensation Discussion and Analysis.

(3) The amounts reflected for 2021 in this column include (i) matching contributions to the Energy Transfer 401(k) Plan made on behalf of the named executive officers of $14,500 each for Messrs. Long, McCrea, Whitehurst, Ramsey, and Mason, and $14,012 for Mr. Sturrock, and (ii) health savings account contributions made on behalf of the named executive officers

of $2,000 each for Messrs. Long, McCrea and Sturrock, and (iii) the dollar value of life insurance premiums paid for the benefit of the named executive officers. The amounts reflected for all periods exclude distribution payments in connection with distribution equivalent rights on unvested unit awards, because the dollar value of such distributions are factored into the grant date fair value reported in the “Equity Awards” column of the Summary Compensation Table at the time that the unit awards and distribution equivalent rights were originally granted. For 2021, distribution payments in connection with distribution equivalent rights totaled $1,008,501 for Mr. Long, $1,624,728 for Mr. McCrea, $566,604 for Mr. Whitehurst, $704,130 for Mr. Ramsey, $504,426 for Mr. Mason, and $86,718 for Mr. Sturrock; these amounts include distribution payments on Sunoco LP unit awards for those executives with such unvested awards.

(4) The amounts reflected in the bonus column for Mr. McCrea includes the second payment of Mr. McCrea’s time-vested cash award, which award represented 50% of Mr. McCrea’s total equity award target in 2020. These bonus amounts were paid as follows: $1,800,000 on December 31, 2020 and $1,600,000 on July 1, 2020. A final unvested amount of $1,600,000 remains outstanding and is scheduled to vest on December 5, 2022. For 2021, the bonus amount reflected above also includes the vesting and payment on February 1, 2021 of a one-time, time-vested cash award of $1,625,000 to Mr. McCrea, which was originally granted in October 2020 in connection with Mr. McCrea’s assumption of his role as Co-Chief Executive Officer.

Grants of Plan-Based Awards in 2021

Name	Grant Date	All Other Unit Awards: Number of Units (#)	Grant Date Fair Value of Unit Awards (1)
Energy Transfer Unit Awards:			
Thomas E. Long	12/16/2021	1,121,250	$ 9,519,413
	12/30/2020 (2)	483,630	2,979,161
Marshal S. (Mackie) McCrea, III	12/16/2021	1,121,250	9,519,413
	12/30/2020 (2)	241,815	1,489,580
Bradford D. Whitehurst	12/16/2021	228,000	1,935,720
Thomas P. Mason	12/16/2021	300,300	2,549,547
A. Troy Sturrock	12/16/2021	57,375	487,114
Energy Transfer Cash Restricted Unit Awards:			
Thomas E. Long	12/16/2021	373,750	2,725,465
Marshal S. (Mackie) McCrea, III	12/16/2021	373,750	2,725,465
Bradford D. Whitehurst	12/16/2021	76,000	554,208
Thomas P. Mason	12/16/2021	100,100	729,951
A. Troy Sturrock	12/16/2021	19,125	139,464
Sunoco LP Unit Awards:			
Bradford D. Whitehurst	12/16/2021	16,100	612,766

(1) We have computed the grant date fair value of unit awards in accordance with FASB ASC Topic 718, as further described above and in Note 9 to our consolidated financial statements. For Energy Transfer cash restricted unit awards, the grant date fair value is discounted for the expected distribution yield during the vesting period, as those awards do not include distribution equivalent rights.

(2) The December 30, 2020 grants to Messrs. Long and McCrea related to their January 1, 2021 promotions to Co-CEOs, and as such has been included with their 2021 compensation.

Narrative Disclosure to Summary Compensation Table and Grants of the Plan-Based Awards Table

A description of material factors necessary to understand the information disclosed in the tables above with respect to salaries, bonuses, equity awards, and 401(k) plan contributions can be found in the Compensation Discussion and Analysis that precedes these tables.

Outstanding Equity Awards at 2021 Fiscal Year-End

		Unit Awards (1)	
Name	**Grant Date(1)**	**Number of Units That Have Not Vested(2) (#)**	**Market or Payout Value of Units That Have Not Vested (3) ($)**
Energy Transfer Unit Awards:			
Thomas E. Long	12/30/2021	1,121,250	$ 9,227,888
	12/30/2020	662,180	5,449,741
	12/16/2019	215,000	1,769,450
	12/18/2018	54,590	449,276
	10/19/2018	46,080	379,238
	12/20/2017	48,430	398,579
Marshal S. (Mackie) McCrea, III	12/30/2021	1,121,250	9,227,888
	12/30/2020	988,165	8,132,598
	12/16/2019	682,400	5,616,152
	12/18/2018	242,296	1,994,096
	12/20/2017	214,952	1,769,055
Bradford D. Whitehurst	12/16/2021	228,000	1,876,440
	12/30/2020	166,600	1,371,118
	12/16/2019	152,300	1,253,429
	12/18/2018	54,076	445,045
	12/20/2017	38,378	315,851
Matthew S. Ramsey	12/30/2020	207,300	1,706,079
	12/16/2019	189,600	1,560,408
	12/18/2018	67,304	553,912
	12/20/2017	89,564	737,112
Thomas P. Mason	12/16/2021	300,300	2,471,469
	12/30/2020	234,900	1,933,227
	12/16/2019	214,800	1,767,804
	12/18/2018	76,256	627,587
	12/20/2017	54,120	445,408
A. Troy Sturrock	12/16/2021	57,375	472,196
	12/30/2020	45,500	374,465
	12/16/2019	42,000	345,660
	12/18/2018	13,000	106,990
	12/20/2017	12,902	106,183
Energy Transfer Cash Restricted Unit Awards:			
Thomas E. Long	12/16/2021	373,750	2,628,986
	12/30/2020	119,034	871,923
Marshal S. (Mackie) McCrea, III	12/16/2021	373,750	2,628,986
Bradford D. Whitehurst	12/16/2021	76,000	534,590
	12/30/2020	111,067	813,565
Matthew S. Ramsey	12/30/2020	138,200	1,012,314
Thomas P. Mason	12/16/2021	100,100	704,111
	12/30/2020	156,600	1,147,094
A. Troy Sturrock	12/16/2021	19,125	134,527
	12/30/2020	30,334	222,196
Sunoco LP Unit Awards:			
Thomas E. Long	12/30/2020	27,800	1,135,074

	12/16/2019	19,500	796,185
	12/19/2018	7,730	315,616
	12/21/2017	6,839	279,236
Bradford D. Whitehurst	12/16/2021	16,100	657,363
	12/30/2020	26,000	1,061,580
	12/16/2019	18,200	743,106
	12/19/2018	7,658	312,676
	12/21/2017	5,420	221,299
Matthew S. Ramsey	12/30/2020	32,300	1,318,809
	12/16/2019	22,600	922,758
	12/19/2018	9,530	389,110
Thomas P. Mason	12/21/2017	7,643	312,064

(1) Certain of these outstanding awards represent subsidiary awards that converted into Energy Transfer awards upon the in connection with restructuring transactions in prior periods.

(2) Energy Transfer and Sunoco LP unit awards outstanding vest as follows:

- at a rate of 60% in December 2024 and 40% in December 2026 for awards granted in December 2021;
- at a rate of 60% in December 2023 and 40% in December 2025 for awards granted in December 2020;
- at a rate of 60% in December 2022 and 40% in December 2024 for awards granted in December 2019;
- 100% in December 2023 for the remaining outstanding portion of awards granted in October and December 2018; and
- 100% in December 2022 for the remaining outstanding portion of awards granted in December 2017.

Such awards may be settled at the election of the Energy Transfer Compensation Committee in (i) common units of Energy Transfer (subject to the approval of the Energy Transfer Incentive Plans prior to the first vesting date by a majority of Unitholders pursuant to the rules of the New York Stock Exchange); (ii) cash equal to the Fair Market Value (as such term is defined in the Energy Transfer Incentive Plans) of the Energy Transfer common units that would otherwise be delivered pursuant to the terms of each named executive officers grant agreement; or (iii) other securities or property in an amount equal to the Fair Market Value of Energy Transfer common units that would otherwise be delivered pursuant to the terms of the grant agreement, or a combination thereof as determined by the Energy Transfer Compensation Committee in its discretion.

Energy Transfer cash restricted unit awards granted in December 2021 vest 1/3 per year in December 2022, 2023 and 2024. The remaining outstanding Energy Transfer cash restricted unit awards granted in December 2020 vest 1/2 per year in December 2022 and 2023.

(3) Market value was computed as the number of unvested awards as of December 31, 2021 multiplied by the closing price of respective common units of Energy Transfer and Sunoco LP. For Energy Transfer cash restricted unit awards, the grant date fair value is discounted for the expected distribution yield during the vesting period, as those awards do not include distribution equivalent rights.

Units Vested in 2021

Name	Unit Awards	
	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($) [1]
Energy Transfer Unit Awards:		
Thomas E. Long	181,241	$ 1,482,551
Marshall S. (Mackie) McCrea, III	535,675	4,381,822
Bradford D. Whitehurst	109,741	897,681
Matthew S. Ramsey	174,396	1,426,559
Thomas P. Mason	155,029	1,268,137
A. Troy Sturrock	28,758	235,240
Energy Transfer Cash Restricted Unit Awards:		
Thomas E. Long	59,516	486,841
Bradford D. Whitehurst	55,533	454,260
Matthew S. Ramsey	69,100	565,238
Thomas P. Mason	78,300	640,494
A. Troy Sturrock	15,166	124,058
Sunoco LP Unit Awards:		
Thomas E. Long	20,479	780,659
Bradford D. Whitehurst	18,051	688,104
Matthew S. Ramsey	14,295	544,925
Thomas P. Mason	9,320	355,278

(1) Amounts presented represent the value realized upon vesting of these awards, which is calculated as the number of units vested multiplied by the applicable closing market price of applicable common units upon the vesting date.

We have not issued option awards.

Potential Payments Upon a Termination or Change of Control

Equity Awards. As discussed in our Compensation Discussion and Analysis above, any unvested equity awards (including cash restricted unit awards) granted pursuant the Energy Transfer Incentive Plans will automatically become vested upon a change of control, which is generally defined as the occurrence of one or more of the following events: (i) any person or group becomes the beneficial owner of 50% or more of the voting power or voting securities of Energy Transfer or its general partner; (ii) LE GP, LLC or an affiliate of LE GP, LLC ceases to be the general partner of Energy Transfer; or (iii) the sale or other disposition, including by liquidation or dissolution, of all or substantially all of the assets of Energy Transfer in one or more transactions to anyone other than an affiliate of Energy Transfer.

In addition, as explained in *Equity Awards* section of our Compensation Discussion and Analysis above, the restricted unit awards, phantom unit awards and cash restricted unit awards under the Energy Transfer Incentive Plans, the Sunoco LP Plan and the 2012 Sunoco LP Plan generally require the continued employment of the recipient during the vesting period, provided however, the unvested awards will be accelerated in the event of the death or disability of the award recipient prior to the applicable vesting period being satisfied. All awards outstanding to the named executive officers under the Energy Transfer Incentive Plans, the 2018 Sunoco LP Plan or the 2012 Sunoco LP Plan would be accelerated in the event of a change in control of the Partnership.

The October 2018 equity award to Mr. Long included a provision in the applicable award agreement for acceleration of unvested restricted unit/restricted phantom unit awards upon a termination of employment by the general partner of the applicable partnership issuing the award without "cause." For purposes of the awards the term "cause" shall mean: (i) a conviction (treating a nolo contendere plea as a conviction) of a felony (whether or not any right to appeal has been or may be exercised), (ii) willful refusal without proper cause to perform duties (other than any such refusal resulting from incapacity due to physical or mental impairment), (iii) misappropriation, embezzlement or reckless or willful destruction of property of the partnership or any of its affiliates, (iv) knowing breach of any statutory or common law duty of loyalty to the partnership or any of its or their affiliates, (v) improper conduct materially prejudicial to the business of the partnership or any of its or their affiliates, (vi) material breach of the provisions of any agreement regarding confidential information entered into with the partnership or any of its or their affiliates or (vii) the continuing failure or refusal to satisfactorily perform essential duties to the partnership or any of its or their affiliates.

In addition, the Energy Transfer Compensation Committee and the compensation committee of the general partner of Sunoco LP, have approved a retirement provision, which provides that employees, including the named executive officers with at least ten years of service with the general partner, who leave the respective general partner voluntarily due to retirement (i) after age 65 but prior to age 68 are eligible for accelerated vesting of 40% of his or her award; or (ii) after 68 are eligible for accelerated vesting of 50% his or her award. The acceleration of the awards is subject to the applicable provisions of IRC Section 409(A).

Deferred Compensation Plan. As discussed in our Compensation Discussion and Analysis above, all amounts under the Energy Transfer NQDC Plan (other than discretionary credits) are immediately 100% vested. Upon a change of control (as defined in the Energy Transfer NQDC Plan), distributions from the respective plan would be made in accordance with the normal distribution provisions of the respective plan. A change of control is generally defined in the Energy Transfer NQDC Plan as any change of control event within the meaning of Treasury Regulation Section 1.409A-3(i)(5).

CEO Pay Ratio

In accordance with Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, set forth below is information about the relationship of the annual total compensation of Messrs. Long and McCrea, Co-Chief Executive Officers and the annual total compensation of our employees.

For the 2021 calendar year, the annual total compensation of Messrs. Long and McCrea, as reported in the Summary Compensation Table of this Item 11 was $19,730,203 and $21,460,652, respectively.

The median total compensation of the employees supporting the Partnership (other than Messrs. Long and McCrea) was $136,935 for 2021, which amount was updated from the 2020 “median employee.”

Based on this information, for 2021 the ratio of the annual total compensation of Messrs. Long and McCrea to the median of the annual total compensation of the 7,965 employees supporting the Partnership as of December 31, 2021 was approximately 144 to 1 and 157 to 1, respectively.

To identify the median of the annual total compensation of the employees supporting the Partnership, the following steps were taken:

1. It was determined that, as of December 31, 2021, the applicable employee populations consisted of 7,965 with all of the identified individuals being employed in the United States. This population consisted of all of our full-time and part-time employees. We did not engage any independent contractors in 2021 that are required to be included in our employee population for the CEO pay ratio evaluation.
2. To identify the “median employee” from our employee population, we compared the total earnings of our employees as reflected in our payroll records as reported on Form W-2 for 2020, and for 2021, updated the compensation of the “median employee” as reflected in our payroll records as reported on form W-2 for 2021.
3. We identified our median employee using W-2 reporting and applied this compensation measure consistently to all of our employees required to be included in the calculation. We did not make any cost of living adjustments in identifying the “median employee.”
4. Once we identified our median employee, we combined all elements of the employee’s compensation for 2021 resulting in an annual compensation of $136,935 with total base salary $109,259. The difference between such employee’s total earnings and the employee’s total compensation represents the estimated value of the employee’s health care benefits (estimated for the employee and such employee’s eligible dependents at $13,071) and the employee’s 401(k) matching contribution and profit sharing contribution (estimated at $5,249 per employee, includes $3,279 per employee on average matching contribution and $1,970 per employee on average profit sharing contribution (employees earning over $175,000 in base are ineligible for profit sharing)).
5. With respect to Messrs. Long and McCrea, we used the amount reported in the “Total” column of our 2021 Summary Compensation Table under this Item 11.

Director Compensation

In 2021, the compensation arrangements for outside directors included a $100,000 annual retainer for services on the board. If a director served on the Energy Transfer Audit Committee, such director would receive an annual cash retainer ($15,000 or $25,000 in the case of the chairman). If a director served on the Energy Transfer Compensation Committee, such director would receive an annual cash retainer ($7,500 or $15,000 in the case of the chairman). The fees for membership on the Conflicts Committee are determined on a per instance basis for each committee assignment.

The outside directors of our General Partner are also entitled to an annual restricted unit award under the Energy Transfer Incentive Plans equal to an aggregate of $100,000 divided by the closing price of Energy Transfer common units on the date of grant. These Energy Transfer common units will vest 60% after the third year and the remaining 40% after the fifth year after the grant date. The compensation expense recorded is based on the grant-date market value of the Energy Transfer common units and is recognized over the vesting period. Distributions are paid during the vesting period.

The compensation paid to the non-employee directors of our General Partner in 2021 is reflected in the following table:

Name	Fees Paid in Cash[(1)] ($)	Unit Awards[(2)] ($)	All Other Compensation ($)	Total ($)
Steven R. Anderson	$ 122,500	$ 100,003	$ —	$ 222,503
Richard D. Brannon	125,000	100,003	—	225,003
Ray C. Davis	100,000	100,003	—	200,003
Michael K. Grimm	130,000	100,003	—	230,003
James R. Perry	100,000	100,003	—	200,003
Ray W. Washburne	107,500	100,003	—	207,503

(1) Fees paid in cash are based on amounts paid during the period.

(2) Equity award amounts reflect the aggregate grant date fair value of unit awards granted for the periods presented, computed in accordance with FASB ASC Topic 718, disregarding any estimates for forfeitures. See Note 9 to our consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" for additional assumptions underlying the value of the equity awards.

As of December 31, 2021, Mr. Anderson had 32,437 unvested Energy Transfer restricted units outstanding, Mr. Brannon had 35,779 unvested Energy Transfer restricted units outstanding, Mr. Davis had 32,437 unvested Energy Transfer restricted units outstanding, Mr. Grimm had 36,327 unvested Energy Transfer restricted units outstanding, Mr. Perry had 26,390 unvested Energy Transfer restricted units outstanding and Mr. Washburne had 26,390 unvested Energy Transfer restricted units outstanding.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Equity Compensation Plan Information

The following table sets forth in tabular format, a summary of our equity plan information as of December 31, 2021:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	—	$ —	—
Equity compensation plans not approved by security holders:	36,145,891	—	12,679,239
Total	36,145,891	$ —	12,679,239

Energy Transfer LP Units

The following table sets forth certain information as of February 11, 2022, regarding the beneficial ownership of our voting securities by (i) certain beneficial owners of more than 5% of our Common Units, (ii) each director and named executive officer of our General Partner and (iii) all current directors and executive officers of our General Partner as a group. The General Partner knows of no other person not disclosed herein who beneficially owns more than 5% of our Common Units.

	Beneficially Owned [2]		Percent of Class	
Name and Address of Beneficial Owner [1]	Common Units	Class A Units[3]	Common Units	Class A Units
Kelcy L. Warren [4]	279,049,984	763,021,449	9.1 %	100.0 %
Ray C. Davis [5]	90,114,776	—	2.9 %	N/A
Thomas E. Long	666,018	—	*	N/A
Marshall S. (Mackie) McCrea, III	2,752,342	—	*	N/A
Matthew S. Ramsey	568,077	—	*	N/A
Thomas P. Mason	633,068	—	*	N/A
Bradford D. Whitehurst [6]	436,512	—	*	N/A
A. Troy Sturrock	89,008	—	*	N/A
Richard D. Brannon [7]	471,629	—	*	N/A
Steven R. Anderson [8]	1,550,656	—	*	N/A
Michael K. Grimm [9]	151,400	—	*	N/A
John W. McReynolds [10]	30,225,200	—	1.0 %	N/A
James R. Perry	120,020	—	*	N/A
Ray W. Washburne [11]	604,302	—	*	N/A
Blackstone Holdings I/II GP L.L.C. [12]	171,553,052	—	5.6 %	N/A
All Directors and Executive Officers as a group (14 persons)	407,432,992	763,021,449	13.2 %	100.0 %

* Less than 1%

(1) The address for Mr. Davis is 5950 Sherry Lane, Dallas, Texas 75225. The address for all other listed beneficial owners is 8111 Westchester Drive, Suite 600, Dallas, Texas 75225.

(2) Beneficial ownership for the purposes of this table is defined by Rule 13d-3 under the Exchange Act of 1934. Under that rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof or to dispose or direct the disposition thereof or has the right to acquire either of those powers within

sixty days. The nature of beneficial ownership for all listed persons is direct with sole investment and disposition power unless otherwise noted. The beneficial ownership of each listed person is based on 3,082,828,515 common units outstanding in the aggregate as of February 11, 2022.

(3) The Energy Transfer Class A Units are entitled to vote together with the Partnership's common units and are not entitled to distributions and otherwise have no economic attributes. The Energy Transfer Class A Units are not convertible into, or exchangeable for, Partnership common units. Under the terms of the Energy Transfer Class A Units, upon the issuance by the Partnership of additional common units or any securities that have voting rights that are pari passu with the Partnership common units, the Partnership will issue to the general partner additional Energy Transfer Class A Units such that Mr. Warren, through his majority ownership of our general partner, maintains the approximately 20% voting percentage in the Partnership represented by such Energy Transfer Class A Units equivalent to such Energy Transfer Class A Unit voting interest prior to such issuance of additional common units. This provision of the Energy Transfer Class A Units shall terminate at such time as Mr. Warren ceases to be an officer or director of our general partner, provided that all Energy Transfer Class A Units outstanding at such time shall be unchanged and remain outstanding. Mr. Warren's combined common unit and Energy Transfer Class A Unit ownership results in a voting interest in the Partnership of 27.1%.

(4) Includes 120,385,650 common units held by Kelcy Warren Partners, L.P. and 10,244,429 common units held by Kelcy Warren Partners II, L.P., the general partners of which are owned by Mr. Warren. Also includes 100,577,803 common units held by Kelcy Warren Partners III, LLC formerly known as Seven Bridges Holdings, LLC, of which Mr. Warren is a member. Also includes 328,383 common units attributable to the interest of Mr. Warren in ET Company Ltd and Three Dawaco, Inc., over which Mr. Warren exercises shared voting and dispositive power with Ray Davis. Also includes 601,076 common units and 763,021,449 Energy Transfer Class A Units held by LE GP, LLC. Mr. Warren may be deemed to own common units and Energy Transfer Class A Units held by LE GP, LLC due to his ownership of 81.2% of its member interests. Mr. Warren disclaims beneficial ownership of common units and Energy Transfer Class A Units owned by LE GP, LLC other than to the extent of his interest in such entity. Also includes 104,166 common units held by Mr. Warren's spouse. Mr. Warren's combined common unit and Energy Transfer Class A Unit ownership results in a voting interest in the Partnership of 27.1%.

(5) Includes 51,701 Common Units held by Avatar Holdings LLC, 1,941,721 common units held by Avatar BW, Ltd., 28,203,003 common units held by Avatar ETC Stock Holdings LLC, 3,557,757 common units held by Avatar Investments LP, 121,117 common units held by Avatar Stock Holdings, LP and 1,112,069 common units held by RCD Stock Holdings, LLC, all of which entities are owned or controlled by Mr. Davis. Also includes 15,987,283 common units held by a remainder trust for Mr. Davis' spouse and 9,536,054 Common Units held by two trusts for the benefit of Mr. Davis' grandchildren, for which Mr. Davis serves as trustee. Mr. Davis shares voting and dispositive power with his wife with respect to common units held directly. Also includes 328,383 common units attributable to ET Company Ltd. Mr. Davis is a former executive officer and director of ETO and is currently a director of the general partner of Energy Transfer, LE GP, LLC.

(6) Includes 235,130 common units held by Mr. Whitehurst in a margin account.

(7) Includes 362,320 common units held by B4 Capital Investments, LP, a limited partnership of which a limited liability company owned by Mr. Brannon and his wife is the sole general partner and of which Mr. Brannon and his wife are the sole limited partners.

(8) Includes 1,544,558 common units held by Steven R. Anderson Revocable Trust, for which Mr. Anderson serves as trustee. As of December 31, 2020, 603,100 common units were pledged as collateral.

(9) Includes 10,800 common units held by two trusts for the benefit of Mr. Grimm's children, for which Mr. Grimm serves as trustee.

(10) Includes 17,445,608 common units held by McReynolds Energy Partners L.P. and 12,142,593 common units held by McReynolds Equity Partners L.P., the general partners of which are owned by Mr. McReynolds. Mr. McReynolds disclaims beneficial ownership of common units owned by such limited partnerships other than to the extent of his interest in such entities.

(11) Includes 2,090 common units held by Mr. Washburne's wife and 502,172 common units held in various family trusts.

(12) This information is based on a Schedule 13G filed on February 11, 2022 by Blackstone Holdings I/II GP L.L.C. on behalf of itself and Blackstone Inc., Blackstone Group Management L.L.C., and Stephen A. Schwarzman, each of which reported sole voting and dispositive power with respect to 171,553,052 Energy Transfer Common Units. The sole member of Blackstone Holdings I/II GP L.L.C. is Blackstone Inc. The sole holder of the Series II preferred stock of Blackstone Inc. is Blackstone Group Management L.L.C. Blackstone Group Management L.L.C. is wholly-owned by Blackstone's senior

managing directors and controlled by its founder, Stephen A. Schwarzman. The address for each reporting person identified in the February 11, 2022 filing was 345 Park Avenue, New York, NY 10154.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The Partnership's principal sources of cash flow are derived from cash flows from the operations of its subsidiaries, including its direct and indirect investments in the limited partner and general partner interests in Sunoco LP and USAC, both of which are limited partnerships engaged in energy-related services.

In making its director independence determination, the Board considered business arrangements involving a director who owns equity interest in, and is the CEO of, a company that owns working interests in oil and gas wells, and affiliates of the Partnership who made nominal payments to that company. None of the arrangements involved payments to the company of more than $1 million in any of the past three fiscal years and the Board determined that the relationship did not impact the director's independence.

For a discussion of director independence, see "Item 10. Directors, Executive Officers and Corporate Governance."

As a policy matter, our Conflicts Committee generally reviews any proposed related party transaction that may be material to the Partnership to determine whether the transaction is fair and reasonable to the Partnership. The Partnership's board of directors makes the determinations as to whether there exists a related party transaction in the normal course of reviewing transactions for approval as the Partnership's board of directors is advised by its management of the parties involved in each material transaction as to which the board of directors' approval is sought by the Partnership's management. In addition, the Partnership's board of directors makes inquiries to independently ascertain whether related parties may have an interest in the proposed transaction. While there are no written policies or procedures for the board of directors to follow in making these determinations, the Partnership's board makes those determinations in light of its contractually-limited fiduciary duties to the Unitholders. The partnership agreement of Energy Transfer provides that any matter approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to Energy Transfer, approved by all the partners of Energy Transfer and not a breach by the General Partner or its Board of Directors of any duties they may owe Energy Transfer or the Unitholders (see "Risks Related to Conflicts of Interest" in "Item 1A. Risk Factors" in this annual report).

Additional information on our related party transactions is included in Note 2 to the Partnership's consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data."

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following sets forth fees billed by Grant Thornton LLP for the audit of our annual financial statements and other services rendered (dollars in millions):

	Years Ended December 31,	
	2021	2020
Audit fees [1]	$ 10.7	$ 10.7
Audit-related fees[2]	0.3	—
Total	$ 11.0	$ 10.7

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and services related to the audit of our internal control over financial reporting.

(2) Includes fees for financial due diligence related to acquisitions.

Pursuant to the charter of the Audit Committee, the Audit Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and establish the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee. All fees paid or expected to be paid to Grant Thornton LLP for fiscal years 2021 and 2020 were pre-approved by the Audit Committee in accordance with this policy.

The Audit Committee reviews the external auditors' proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors' internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two years; and
- the rotation of the lead partner.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this Report:	Page
(1) Financial Statements – see Index to Financial Statements	F - 1
(2) Financial Statement Schedules – None	
(3) Exhibits – see Index to Exhibits	168

ITEM 16. FORM 10-K SUMMARY

None.

INDEX TO EXHIBITS

The exhibits listed on the following Exhibit Index are filed as part of this report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of September 15, 2019, by and among Energy Transfer LP, Nautilus Merger Sub LLC and SemGroup Corporation (incorporated by reference to Exhibit 2.1 to Form 8-K (File No. 1-32740) filed September 16, 2019)
2.2	Agreement and Plan of Merger, dated as of February 16, 2021, by and among Energy Transfer LP, Elk Merger Sub LLC, Elk GP Merger Sub LLC, Enable Midstream Partners, LP, Enable GP, LLC, solely for the purpose of Section 21.(a)(i), LE GP, LLC, and, solely for the purpose of Section 1.1(b)(i), CenterPoint Energy, Inc. (incorporated by reference to Exhibit 2.1 to Form 8-K (File No. 1-32740) filed February 17, 2021)
2.3	Agreement and Plan of Merger, dated as of March 5, 2021, by and among Energy Transfer LP, ETO Merger Sub LLC and Energy Transfer Operating, L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K (File No. 1-32740) filed March 5, 2021)
2.4	Agreement and Plan of Merger, dated as of April 1, 2021, by and among Energy Transfer Operating, L.P., Sunoco Logistics Partners Operations L.P. and Sunoco Logistics Partners GP LLC (incorporated by reference to Exhibit 2.1 to Form 8-K (File No. 1-32740) filed April 2, 2021)
2.5	Agreement and Plan of Merger, dated as of April 1, 2021, by and among Energy Transfer LP and Energy Transfer Operating, L.P. (incorporated by reference to Exhibit 2.2 to Form 8-K (File No. 1-32740) filed April 2, 2021)
3.1	Certificate of Limited Partnership of Energy Transfer Equity, L.P. (incorporated by reference to Exhibit 3.2 to Form S-1 (File No. 333-128097) filed September 2, 2005)
3.1.1	Certificate of Amendment to Certificate of Limited Partnership of Energy Transfer LP (incorporated by reference to Exhibit 3.1 to Form 8-K (File No. 1-32740) filed October 19, 2018)
3.2	Third Amended Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated February 8, 2006 (incorporated by reference to Exhibit 3.1 to Form 8-K (File No. 1-32740) filed February 14, 2006)
3.3	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 to Form 10-K (File No. 1-32740) filed November 29, 2006)
3.4	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 to Form 8-K (File No. 1-32740) filed November 13, 2007)
3.5	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 to Form 8-K (File No. 1-32740) filed June 2, 2010)
3.6	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 to Form 8-K (File No. 1-32740) filed December 27, 2013)
3.7	Amendment No. 5 to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated as of March 8, 2016 (incorporated by reference to Exhibit 3.1 to Form 8-K (File No. 1-32740) filed March 9, 2016)
3.8	Amendment No. 6 to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated as of October 19, 2018 (incorporated by reference to Exhibit 3.2 of Form 8-K, File No.1-32740, filed October 19, 2018 (incorporated by reference to Exhibit 3.2 to Form 8-K (File No. 1-32740) filed October 19, 2018)
3.9	Amendment No. 7 to the Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP dated as of August 6, 2019 (incorporated by reference to Exhibit 3.10 to Form 10-Q (File No. 1-32740) filed August 8, 2019)
3.10	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)
3.11	Amendment No. 9 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer LP, dated June 15, 2021 (incorporated by reference to Exhibit 3.1 of Form 8-K (File No. 1-32740) filed June 15, 2021)
4.1	Indenture, dated September 20, 2010 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K (File No. 1-32740) filed September 20, 2010)

Exhibit Number	Description
4.2	Fourth Supplemental Indenture, dated December 2, 2013 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-32740) filed December 2, 2013)
4.3	Fifth Supplemental Indenture, dated May 28, 2014 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-32740) filed May 28, 2014)
4.4	Sixth Supplemental Indenture, dated May 28, 2014 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K (File No. 1-32740) filed May 28, 2014)
4.5	Seventh Supplemental Indenture, dated May 22, 2015 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-32740) filed May 22, 2015)
4.6	Eighth Supplemental Indenture dated October 18, 2017 between Energy Transfer Equity, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-32740) filed October 18th, 2017)
4.7	Ninth Supplemental Indenture, dated as of March 25, 2019, between Energy Transfer LP and U.S. Bank National Association as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-32740) filed March 27, 2019)
4.8	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K (File No. 1-11727) filed January 19, 2005)
4.9	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K (File No. 1-11727) filed October 25, 2006)
4.10	Sixth Supplemental Indenture dated March 28, 2008, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed March 31, 2008)
4.11	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed May 12, 2011)
4.12	Tenth Supplemental Indenture, dated as of January 17, 2012, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed January 17, 2012)
4.13	Eleventh Supplemental Indenture dated as of January 22, 2013 by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed January 23, 2013)
4.14	Twelfth Supplemental Indenture, dated as of January 24, 2013, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed June 26, 2013)
4.15	Thirteenth Supplemental Indenture, dated as of September 19, 2013, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed September 19, 2013)
4.16	Fourteenth Supplemental Indenture, dated as of March 12, 2015, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed on March 12, 2015)
4.17	Fifteenth Supplemental Indenture, dated as of June 23, 2015, by and between Energy Transfer Partners, L.P., as issuer, and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K (File No. 1-11727) filed June 23, 2015)
4.18	Sixteenth Supplemental Indenture, dated as of January 17, 2017, between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-11727) filed January 17, 2017)
4.19	Seventeenth Supplemental Indenture, dated as of December 1, 2017, between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee (incorporated by reference to Exhibit 10.8 to Form 8-K (File No. 1-31219) filed December 6, 2017)
4.20	Second Supplemental Indenture, dated December 1, 2017, among Energy Transfer Partners, L.P., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.5 to Form 8-K (File No. 1-31219) filed December 6, 2017)

Exhibit Number	Description
4.21	Indenture, dated as of May 15, 1994, between Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., relating to Sunoco, Inc.'s 9.00% Debentures due 2024 (incorporated by reference to Exhibit 4.8 to Form 8-K (File No. 1-31219) filed October 5, 2012)
4.22	First Supplemental Indenture, dated as of October 5, 2012, among Energy Transfer Partners, L.P., Sunoco, Inc. and U.S. Bank National Association, as successor trustee to Citibank, N.A., to the Indenture, dated as of May 15, 1994 (incorporated by reference to Exhibit 4.9 to Form 8-K (File No. 1-11727) filed October 5, 2012)
4.23	Sixteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.4 to Form 8-K (File No. 1-31219) filed September 25, 2017)
4.24	Fifteenth Supplemental Indenture, dated as of September 21, 2017, by and among Sunoco Logistics Partners Operations L.P., as issuer, Energy Transfer Partners, L.P., as guarantor, and U.S. Bank National Association, as successor trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-31219) filed September 25, 2017)
4.25	Third Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-31219) filed December 15, 2017)
4.26	Eighteenth Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.2 to Form 8-K (File No. 1-31219) filed December 15, 2017)
4.27	Tenth Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp., Sunoco Logistics Partners Operations L.P. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to Form 8-K (File No. 1-31219) filed December 15, 2017)
4.28	Eleventh Supplemental Indenture, dated as of December 12, 2017, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp., Sunoco Logistics Partners Operations L.P. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.4 to Form 8-K (File No. 1-31219) filed December 15, 2017)
4.29	Second Supplemental Indenture, dated as of December 1, 2017, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.6 to Form 8-K (File No. 1-31219) filed December 6, 2017)
4.30	Indenture, dated as of June 8, 2018, among Energy Transfer Partners, L.P. as issuer, Sunoco Logistics Partners Operations L.P., as guarantor, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K (File No. 1-31219) filed June 8, 2018)
4.31	First Supplemental Indenture, dated as of June 8, 2018, by and among Energy Transfer Partners, L.P., as issuer, the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-31219) filed June 8, 2018)
4.32	Second Supplemental Indenture, dated as of January 15, 2019, by and among Energy Transfer Operating, L.P., as issuer, the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-31219) filed January 15, 2019)
4.33	Third Supplemental Indenture, dated as of March 25, 2019, by and among Energy Transfer Operating, L.P., as issuer, the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-31219) filed March 27, 2019)
4.34	Fourth Supplemental Indenture dated as of January 22, 2020, by and among Energy Transfer Operating, L.P., as issuer, the subsidiary guarantors named therein, U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File No. 1-31219) filed January 22, 2020)
4.35	Fifth Supplemental Indenture, dated as of December 28, 2021, by and among Energy Transfer LP, Enable Midstream Partners, LP and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Form 8-K (File No. 1-32740) filed December 28, 2021)
4.36	Indenture, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Form 8-K (File No. 1-36413) filed May 29, 2014)
4.37	First Supplemental Indenture, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File no. 1-36413) filed May 29, 2014)
4.38	Second Supplemental Indenture, dated as of March 9, 2017, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File no. 1-36413) filed March 9, 2017)

Exhibit Number	Description
4.39	Third Supplemental Indenture, dated as of May 10, 2018, by and among Enable Midstream Partners, LP and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File no. 1-36413) filed May 10, 2018)
4.40	Fourth Supplemental Indenture, dated as of September 13, 2019, by and among Enable Midstream Partners and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K (File no. 1-36413) filed September 13, 2019)
4.41	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of common units (incorporated by reference to Exhibit 4.10 to Form 10-K (File No. 1-32740) filed February 21, 2020)
4.42*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Listed Senior Notes
4.43*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Series C Preferred Units
4.44*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Series D Preferred Units
4.45*	Description of Registrant's securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 - Description of Series E Preferred Units
10.1+	Amended and Restated Energy Transfer LP Long-Term Incentive Plan (formerly Amended and Restated Energy Transfer Equity, L.P. Long-Term Incentive Plan) (incorporated by reference to Exhibit 10.1 to Form 10-K (File No. 1-32740) filed February 23, 2018)
10.2+	First Amendment to the Amended and Restated Energy Transfer LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 10-K (File No. 1-32740) filed February 19, 2021)
10.3+	Second Amendment to the Amended and Restated Energy Transfer LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-32740) filed January 6, 2021)
10.4+	Energy Transfer LP Long-Term Cash Restricted Unit Plan (incorporated by reference to Exhibit 10.2 to Form 8-K (File No. 1-32740) filed January 6, 2021)
10.5+	Form of Cash Unit Award Agreement under the Energy Transfer LP Long-Term Cash Restricted Unit Plan (incorporated by reference to Exhibit 10.3 to Form 8-K (File No. 1-32740) filed January 6, 2021)
10.6+	Second Amended and Restated Energy Transfer LP 2008 Long-Term Incentive Plan (formerly Second Amended and Restated Energy Transfer Partners, L.P. 2008 Long-Term Incentive Plan) (incorporated by reference to Exhibit 4.1 to Form S-8 (File No. 333-229456) filed January 31, 2019)
10.7+	Energy Transfer LP 2011 Long-Term Incentive Plan (formerly Regency Energy Partners LP 2011 Long-Term Incentive Plan) (incorporated by reference to Exhibit 4.2 to Form S-8 (File No 333-229456) filed January 31, 2019)
10.8+	Energy Transfer LP 2015 Long-Term Incentive Plan, as amended and restated (formerly Sunoco Partners LLC Long-Term Incentive Plan, as amended and restated) (incorporated by reference to Exhibit 4.3 to Form S-8 (File No. 333-229456) filed January 31, 2019)
10.9+	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.26 to Form S-1 (File No. 333-128097) filed December 20, 2005)
10.10+	LE GP, LLC Amended and Restated Outside Director Compensation Policy (incorporated by reference to Exhibit 10.9 to Form 10-K (File No. 1-32740) filed February 22, 2019)
10.11+	Energy Transfer Deferred Compensation Plan (formerly called Energy Transfer Partners Deferred Compensation Plan) (incorporated by reference to Exhibit 10.1 to Form 10-Q (File No. 1-11727) filed May 7, 2010)
10.12+*	Amendment No. 1 to the Energy Transfer Deferred Compensation Plan (formerly called Energy Transfer Partners Deferred Compensation Plan)
10.13+*	Amendment No. 2 to the Energy Transfer Deferred Compensation Plan
10.14+	Retention Agreement, by and among Energy Transfer Equity, L.P. and Thomas P. Mason, dated February 24, 2016 (incorporated by reference to Exhibit 10.21 to Form 10-K (File No. 1-32740) filed February 29, 2016)
10.15+	Energy Transfer LP Annual Bonus Plan (incorporated by reference to Exhibit 10.23 to Form 10-K (File No. 1-32740) filed February 22, 2019)
10.16	Registration Rights Agreement, dated November 27, 2006, by and among Energy Transfer Equity, L.P. and certain investors named therein (incorporated by reference to Exhibit 99.1 to Form 8-K (File No. 1-32740) filed November 30, 2006)
10.17	Registration Rights Agreement, dated March 2, 2007, by and among Energy Transfer Equity, L.P. and certain investors named therein (incorporated by reference to Exhibit 99.1 to Form 8-K (File No. 1-32740) filed March 5, 2007)

Exhibit Number	Description
10.18	Unitholder Rights and Restrictions Agreement, dated as of May 7, 2007, by and among Energy Transfer Equity, L.P., Ray C. Davis, Natural Gas Partners VI, L.P. and Enterprise GP Holdings, L.P. (incorporated by reference to Exhibit 10.45 to Form 8-K (File No. 1-32740) filed May 7, 2007)
10.19	Equity Restructuring Agreement, dated as of January 15, 2018, by and among Energy Transfer Equity, L.P., USA Compression Partners, LP and USA Compression GP, LLC. (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-32740) filed January 16, 2018)
10.20	Registration Rights Agreement, dated as of April 2, 2018, by and among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P., USA Compression Partners, LP and USA Compression Holdings, LLC. (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-32740) filed April 3, 2018)
10.21	Support Agreement, dated as of February 16, 2021, by and among Energy Transfer LP, Elk Merger Sub LLC, Elk GP Merger Sub LLC, Enable Midstream Partners, LP, Enable GP, LLC and CenterPoint Energy, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-32740) filed February 17, 2021)
10.22	Support Agreement, dated as of February 16, 2021, by and among Energy Transfer LP, Elk Merger Sub LLC, Elk GP Merger Sub LLC, Enable Midstream Partners, LP, Enable GP, LLC and OGE Energy Corp. (incorporated by reference to Exhibit 10.2 to Form 8-K (File No. 1-32740) filed February 17, 2021)
10.23	Third Supplemental Indenture, dated as of April 1, 2021 by and between Energy Transfer LP and U.S. Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-32740) filed April 2, 2021)
10.24	Fourth Supplemental Indenture, dated as of April 1, 2021 by and between Energy Transfer LP and U.S. Bank National Association (incorporated by reference to Exhibit 10.2 to Form 8-K (File No. 1-32740) filed April 2, 2021)
10.25	Fifth Supplemental Indenture, dated as of April 1, 2021 by and between Energy Transfer LP and U.S. Bank National Association (incorporated by reference to Exhibit 10.3 to Form 8-K (File No. 1-32740) filed April 2, 2021)
10.26	Seventeenth Supplemental Indenture, dated as of April 1, 2021 by and between Energy Transfer LP and U.S. Bank National Association (incorporated by reference to Exhibit 10.4 to Form 8-K (File No. 1-32740) filed April 2, 2021)
10.27	Nineteenth Supplemental Indenture, dated as of April 1, 2021 by and between Energy Transfer LP and U.S. Bank National Association (incorporated by reference to Exhibit 10.5 to Form 8-K (File No. 1-32740) filed April 2, 2021)
10.28	Eleventh Supplemental Indenture, dated April 1, 2021 by and between Energy Transfer LP, Regency Energy Finance Corp., and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.6 to Form 8-K (File No. 1-32740) filed April 2, 2021)
10.29	Twelfth Supplemental Indenture, dated April 1, 2021 by and between Energy Transfer LP, Regency Energy Finance Corp., and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.7 to Form 8-K (File No. 1-32740) filed April 2, 2021)
10.30	Registration Rights Agreement, dated as of December 2, 2021, by and among Energy Transfer LP, CenterPoint Energy, Inc. and OGE Energy Corp. (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-32740) filed December 3, 2021)
10.31	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.56 to Form 10-Q (File No. 1-11727) filed July 10, 2007)
10.32	Note Purchase Agreement, dated December 9, 2009, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-11727) filed December 14, 2009)
10.33	Credit Agreement dated as of December 1, 2017 among Energy Transfer Partners, L.P., Wells Fargo Bank, National Association, as Administrative Agent, the other lenders party thereto and the other parties named therein (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-31219) filed December 6, 2017)
10.34	Amendment No. 1 to Five-Year Credit Agreement, Joinder and Increase and Extension Agreement, dated as of October 19, 2018, by and among Energy Transfer Partners, L.P., Sunoco Logistics Partners Operations L.P., and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-31219) filed October 19, 2018)
10.35	Extension Agreement dated as of May 10, 2021 among Energy Transfer LP, the Consenting Lenders named therein, Wells Fargo Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-32740) filed May 11, 2021

Exhibit Number	Description
10.36	Sixth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, as guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to Form 8-K (File No. 1-11727) filed April 30, 2015)
10.37	Eighth Supplemental Indenture, dated as of April 30, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Energy Transfer Partners, L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.4 to Form 8-K (File No. 1-11727) filed April 30, 2015)
10.38	Seventh Supplemental Indenture, dated as of May 28, 2015, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the subsidiary guarantors party thereto, Panhandle Eastern Pipe Line Company, LP, Energy Transfer Partners, L.P., as co-obligor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-11727) filed June 1, 2015)
10.39	Eighth Supplemental Indenture, dated as of August 10, 2015, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.2 to Form 8-K (File No. 1-11727) filed August 13, 2015)
10.40	Ninth Supplemental Indenture, dated as of December 1, 2017 by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.9 to Form 8-K (File No. 1-31219) filed December 6, 2017)
10.41	Ninth Supplemental Indenture, dated as of August 10, 2015, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 to Form 8-K (File No. 1-11727) filed August 13, 2015)
10.42	Tenth Supplemental Indenture, dated as of December 1, 2017, by and among Energy Transfer Partners, L.P., Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.10 to Form 8-K (File No. 1-31219) filed December 6, 2017)
10.43	Guarantee of Collection, dated as of April 30, 2013, by and between Regency Energy Partners LP, PEPL Holdings, LLC and Regency Energy Finance Corp. (incorporated by reference to Exhibit 10.3 to Form 8-K (File No. 1-11727) filed April 30. 2013)
10.44	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies (incorporated by reference to Exhibit 10.2 to Form 8-K (File No. 1-11727) filed February 1, 2005)
10.45	Guarantee of Collection, made as of March 26, 2012, by Citrus ETP Finance LLC, to Energy Transfer Partners, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 1-11727) filed March 28, 2012)
10.46	Support Agreement, dated March 26, 2012, by and among PEPL Holdings, LLC, Energy Transfer Partners, L.P., and Citrus ETP Finance LLC (incorporated by reference to Exhibit 10.2 to Form 8-K (File No. 1-11727) filed March 28, 2012)
10.47	Form of Commercial Paper Dealer Agreement between Energy Transfer Partners, L.P., as Issuer, and the Dealer party thereto (incorporated by reference to Exhibit 99.1 to Form 8-K (File No. 1-11727) filed August 22, 2016)
21.1*	List of Subsidiaries
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)
23.1*	Consent of Grant Thornton LLP
31.1*	Certification of Co-Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Co-Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3*	Certification of Chief Financial Officer 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 Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Exhibit Number	Description
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 Statement of Equity; (v) our Consolidated Statements of Cash Flows; and (vi) the notes to our Consolidated Financial Statements
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

*	Filed herewith.
**	Furnished herewith.
+	Denotes a management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: February 18, 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)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Executive Chairman	February 18, 2022
/s/ Marshall S. McCrea, III Marshall S. McCrea, III	Co-Chief Executive Officer and Director (Co-Principal Executive Officer)	February 18, 2022
/s/ Thomas E. Long Thomas E. Long	Co-Chief Executive Officer and Director (Co-Principal Executive Officer)	February 18, 2022
/s/ Bradford D. Whitehurst Bradford D. Whitehurst	Chief Financial Officer (Principal Financial Officer)	February 18, 2022
/s/ Matthew S. Ramsey Matthew S. Ramsey	Chief Operating Officer and Director	February 18, 2022
/s/ A. Troy Sturrock A. Troy Sturrock	Senior Vice President and Controller (Principal Accounting Officer)	February 18, 2022
/s/ Steven R. Anderson Steven R. Anderson	Director	February 18, 2022
/s/ Richard D. Brannon Richard D. Brannon	Director	February 18, 2022
/s/ Ray C. Davis Ray C. Davis	Director	February 18, 2022
/s/ Michael K. Grimm Michael K. Grimm	Director	February 18, 2022
/s/ John W. McReynolds John W. McReynolds	Director	February 18, 2022
/s/ James R. Perry James R. Perry	Director	February 18, 2022
/s/ Ray W. Washburne Ray W. Washburne	Director	February 18, 2022

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Energy Transfer LP and Subsidiaries

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of LE GP, LLC and
Unitholders of Energy Transfer LP

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Energy Transfer LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2021 and 2020, the related consolidated statements of operations, comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Partnership's internal control over financial reporting as of December 31, 2021, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 18, 2022 expressed an unqualified opinion.

Basis for opinion
These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matters
The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Goodwill Impairment Assessment
As described further in Note 2 to the consolidated financial statements, the Partnership's consolidated goodwill balance was $2.5 billion as of December 31, 2021. Management evaluates goodwill for impairment annually on October 1st of each year or whenever events or changes in circumstances indicate potential asset impairment has occurred. As of December 31, 2021, there was $368 million of goodwill associated with a reporting unit within the NGL and Refined Products Transportation services segment in which we identified the Partnership's determination of the fair value of the reporting unit as a critical audit matter.

The principal considerations for our determination that the estimation of the fair value of the reporting unit is a critical audit matter are that there are significant judgments required by management when determining the fair value of the reporting unit. In particular, the fair value estimate was sensitive to significant assumptions used to estimate future revenues and cash flows, including revenue growth rates, operating expenses, discount rate, and the inherent uncertainty around future market conditions as well as valuation methodologies applied by the Partnership.

Our audit procedures related to the determination that the estimation of the fair value of the reporting unit included the following, among others. We tested the effectiveness of controls relating to management's review of the assumptions used to develop the future cash flows, the discount rate used, and valuation methodologies applied. In addition to testing the effectiveness of controls, we also performed the following:

a. Evaluated the reasonableness of management's forecasted financial results by:
    i. Assessing the reasonableness of management's forecast of future projected results by comparing such items to industry projections and conditions found in industry reports,

    ii. Testing forecasted revenues and expected future cash flows by comparing forecasted amounts to actual historical results to identify material changes, corroborating the basis for increases in forecasted revenues and expected future cash flows, as applicable, and
    iii. Testing significant operating expenses and cash expenditures by comparing to historical trends and evaluating significant deviations from recent actual amounts.

b. Utilized an internal valuation specialist to evaluate:
    i. The methodologies used and whether they were acceptable for the underlying assets or operations and whether such methodologies were being applied correctly, and
    ii. The appropriateness of the discount rate by developing an independent range of acceptable discount rates and comparing those ranges to the amounts selected and applied by management.

Acquisition of Enable Midstream Partners, LP

As described in Note 3 to the consolidated financial statements, on December 2, 2021, the Partnership completed the merger of Enable Midstream Partners, LP ("Enable") and the assets acquired and liabilities assumed were required to be recorded at fair value as of the acquisition date. The Partnership utilized a third-party valuation specialist to assist in the preparation of the valuation. We identified the fair value determination of the acquired real and personal property, intangible assets, and residual value of goodwill to be a critical audit matter.

The principal considerations for our determination that estimation of the fair value of the assets acquired in the acquisition of Enable is a critical audit matter are that there was a high estimation uncertainty due to significant judgments with respect to assumptions used to estimate the future revenues and cash flows, including revenue growth rates, operating margins, the discount rate, the valuation methodologies applied by the third-party valuation specialist for the fair value of the intangible assets as well as the real property and estimated replacement costs of the personal property acquired. This in turn led to a high degree of auditor judgment, subjectivity, and efforts in performing procedures and evaluating audit evidence related to management's forecasted future revenues and cash flows and valuation methodologies. In addition, the audit effort involved the use of specialists to assist in performing these procedures and evaluating the audit evidence obtained.

Our audit procedures related to the fair value of assets acquired included the following, among others. We tested the effectiveness of controls relating to management's review of the assumptions used to develop the future revenues and cash flows, the reconciliation of future revenues and cash flows prepared by management to the data used in the valuation report prepared by the third-party specialist, the estimated replacement cost of real and personal property and the valuation methodologies applied by the third-party valuation specialist. In addition to testing the effectiveness of controls, we also performed the following:

a. Evaluated the reasonableness of management's forecasted financial results by:
    i. Assessing the reasonableness of management's forecast of future projected results by comparing such items to industry projections and conditions found in industry reports, and
    ii. Testing forecasted revenues and expected future cash flows by comparing forecasted amounts to actual historical results to identify material changes, corroborating the basis for increases in forecasted revenues and expected future cash flows, as applicable.
b. Utilized an internal valuation specialist to evaluate:
    i. The methodologies used and whether they were acceptable for the underlying assets or operations and being applied correctly by performing independent calculations,
    ii. The methodologies and assumptions used in the valuation of real property,
    iii. The appropriateness of the replacement cost of the personal property, by performing independent calculations and inspecting the estimated remaining years of service for the underlying assets based on the original acquisition dates and condition of assets,
    iv. The appropriateness of the discount rate used by recalculating the weighted average cost of capital, and
    v. The qualification of third-party valuation specialist engaged by the Partnership based on their credentials and experience.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2004.

Dallas, Texas
February 18, 2022

ENERGY TRANSFER LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2021	December 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 336	$ 367
Accounts receivable, net	7,654	3,875
Accounts receivable from related companies	54	79
Inventories	2,014	1,739
Income taxes receivable	32	35
Derivative assets	10	9
Other current assets	437	213
Total current assets	10,537	6,317
Property, plant and equipment	103,991	94,115
Accumulated depreciation and depletion	(22,384)	(19,008)
Property, plant and equipment, net	81,607	75,107
Investments in unconsolidated affiliates	2,947	3,060
Lease right-of-use assets, net	838	866
Other non-current assets, net	1,645	1,657
Intangible assets, net	5,856	5,746
Goodwill	2,533	2,391
Total assets	$ 105,963	$ 95,144

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

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

	December 31,	
	2021	2020
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 6,834	$ 2,809
Accounts payable to related companies	—	27
Derivative liabilities	203	238
Operating lease current liabilities	47	53
Accrued and other current liabilities	3,071	2,775
Current maturities of long-term debt	680	21
Total current liabilities	10,835	5,923
Long-term debt, less current maturities	49,022	51,417
Non-current derivative liabilities	193	237
Non-current operating lease liabilities	814	837
Deferred income taxes	3,648	3,428
Other non-current liabilities	1,323	1,152
Commitments and contingencies		
Redeemable noncontrolling interests	783	762
Equity:		
Limited Partners:		
Preferred Unitholders (72,184,780 units authorized, issued and outstanding as of December 31, 2021)	6,051	—
Common Unitholders (3,082,517,494 and 2,702,372,154 units authorized, issued and outstanding as of December 31, 2021 and 2020, respectively)	25,230	18,531
General Partner	(4)	(8)
Accumulated other comprehensive income	23	6
Total partners’ capital	31,300	18,529
Noncontrolling interests	8,045	12,859
Total equity	39,345	31,388
Total liabilities and equity	$ 105,963	$ 95,144

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

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

	Years Ended December 31,		
	2021	2020	2019
REVENUES:			
Refined product sales	$ 17,766	$ 10,514	$ 16,752
Crude sales	15,299	9,442	15,917
NGL sales	15,243	6,797	8,290
Gathering, transportation and other fees	9,229	8,982	9,086
Natural gas sales	9,159	2,633	3,295
Other	721	586	873
Total revenues	67,417	38,954	54,213
COSTS AND EXPENSES:			
Cost of products sold	50,395	25,487	39,801
Operating expenses	3,574	3,218	3,294
Depreciation, depletion and amortization	3,817	3,678	3,147
Selling, general and administrative	818	711	694
Impairment losses	21	2,880	74
Total costs and expenses	58,625	35,974	47,010
OPERATING INCOME	8,792	2,980	7,203
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(2,267)	(2,327)	(2,331)
Equity in earnings of unconsolidated affiliates	246	119	302
Impairment of investments in unconsolidated affiliates	—	(129)	—
Losses on extinguishments of debt	(38)	(75)	(18)
Gains (losses) on interest rate derivatives	61	(203)	(241)
Other, net	77	12	105
INCOME BEFORE INCOME TAX EXPENSE	6,871	377	5,020
Income tax expense	184	237	195
NET INCOME	6,687	140	4,825
Less: Net income attributable to noncontrolling interests	1,167	739	1,256
Less: Net income attributable to redeemable noncontrolling interests	50	49	51
NET INCOME (LOSS) ATTRIBUTABLE TO PARTNERS	5,470	(648)	3,518
General Partner’s interest in net income (loss)	6	(1)	4
Preferred Unitholders’ interest in net income	285	—	—
Limited Partners’ interest in net income (loss)	$ 5,179	$ (647)	$ 3,514
NET INCOME (LOSS) PER LIMITED PARTNER UNIT:			
Basic	$ 1.89	$ (0.24)	$ 1.34
Diluted	$ 1.89	$ (0.24)	$ 1.33

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

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

	Years Ended December 31,		
	2021	2020	2019
Net income	$ 6,687	$ 140	$ 4,825
Other comprehensive income, net of tax:			
Change in value of available-for-sale securities	1	5	11
Actuarial gain relating to pension and other postretirement benefits	12	18	24
Foreign currency translation adjustment	4	5	6
Change in other comprehensive income from unconsolidated affiliates	3	(13)	(10)
	20	15	31
Comprehensive income	6,707	155	4,856
Less: Comprehensive income attributable to noncontrolling interests	1,170	738	1,256
Less: Comprehensive income attributable to redeemable noncontrolling interests	50	49	51
Comprehensive income (loss) attributable to partners	$ 5,487	$ (632)	$ 3,549

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

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

	Common Unitholders	Preferred Unitholders	General Partner	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total
Balance, December 31, 2018	$ 20,773	$ —	$ (5)	$ (42)	$ 10,291	$ 31,017
Distributions to partners	(3,051)	—	(3)	—	—	(3,054)
Distributions to noncontrolling interests	—	—	—	—	(1,597)	(1,597)
Common units repurchased	(25)	—	—	—	—	(25)
Subsidiary units issued	—	—	—	—	780	780
Capital contributions from noncontrolling interests	—	—	—	—	348	348
Sale of noncontrolling interest in subsidiary	—	—	—	—	93	93
SemGroup Acquisition	652	—	—	—	819	1,471
Other comprehensive income, net of tax	—	—	—	31	—	31
Other, net	72	—	—	—	28	100
Net income, excluding amounts attributable to redeemable noncontrolling interests	3,514	—	4	—	1,256	4,774
Balance, December 31, 2019	21,935	—	(4)	(11)	12,018	33,938
Distributions to partners	(2,799)	—	(3)	—	—	(2,802)
Distributions to noncontrolling interests	—	—	—	—	(1,651)	(1,651)
Subsidiary units issued	—	—	—	—	1,580	1,580
Capital contributions from noncontrolling interests	—	—	—	—	222	222
Other comprehensive income (loss), net of tax	—	—	—	16	(1)	15
Other, net	42	—	—	1	(48)	(5)
Net income (loss), excluding amounts attributable to redeemable noncontrolling interests	(647)	—	(1)	—	739	91
Balance, December 31, 2020	18,531	—	(8)	6	12,859	31,388
Preferred units converted in Rollup Mergers	—	4,768	—	—	(4,768)	—
Distributions to partners	(1,616)	(280)	(2)	—	—	(1,898)
Distributions to noncontrolling interests	—	—	—	—	(1,487)	(1,487)
Common units repurchased	(31)	—	—	—	—	(31)
Units issued	—	889	—	—	—	889
Capital contributions from noncontrolling interests	—	—	—	—	226	226
Enable Acquisition	3,117	392	—	—	34	3,543
Other comprehensive income, net of tax	—	—	—	17	3	20
Other, net	50	(3)	—	—	11	58
Net income, excluding amounts attributable to redeemable noncontrolling interests	5,179	285	6	—	1,167	6,637
Balance, December 31, 2021	$ 25,230	$ 6,051	$ (4)	$ 23	$ 8,045	$ 39,345

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)

	Years Ended December 31,		
	2021	2020	2019
OPERATING ACTIVITIES:			
Net income	$ 6,687	$ 140	$ 4,825
Reconciliation of net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	3,817	3,678	3,147
Deferred income taxes	141	210	217
Inventory valuation adjustments	(190)	82	(79)
Non-cash compensation expense	111	121	113
Impairment losses	21	2,880	74
Impairment of investment in unconsolidated affiliates	—	129	—
Losses on extinguishments of debt	38	75	18
Distributions on unvested awards	(47)	(41)	(38)
Equity in earnings of unconsolidated affiliates	(246)	(119)	(302)
Distributions from unconsolidated affiliates	212	220	290
Other non-cash	103	(61)	182
Net change in operating assets and liabilities, net of effects of acquisitions	515	47	(391)
Net cash provided by operating activities	11,162	7,361	8,056
INVESTING ACTIVITIES:			
Cash received in Enable Acquisition, net of cash paid	51	—	—
Cash proceeds from sale of noncontrolling interest in subsidiary	—	—	93
Cash paid for SemGroup Acquisition, net of cash received	—	—	(787)
Cash paid for all other acquisitions	(256)	—	(7)
Capital expenditures, excluding allowance for equity funds used during construction	(2,822)	(5,130)	(5,960)
Contributions in aid of construction costs	43	67	80
Contributions to unconsolidated affiliates	(4)	(38)	(523)
Distributions from unconsolidated affiliates in excess of cumulative earnings	167	187	98
Proceeds from sales of other assets	45	19	54
Other	1	(3)	18
Net cash used in investing activities	(2,775)	(4,898)	(6,934)

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

FINANCING ACTIVITIES:			
Proceeds from borrowings	21,267	24,440	22,583
Repayments of debt	(27,318)	(24,133)	(20,101)
Preferred units issued for cash	889	—	—
Subsidiary units issued for cash	—	1,580	780
Capital contributions from noncontrolling interests	226	222	348
Distributions to partners	(1,898)	(2,802)	(3,054)
Distributions to noncontrolling interests	(1,487)	(1,651)	(1,597)
Distributions to redeemable noncontrolling interests	(49)	(49)	(53)
Common units repurchased under buyback program	(31)	—	(25)
Debt issuance costs	(14)	(59)	(117)
Other	(3)	65	(14)
Net cash used in financing activities	(8,418)	(2,387)	(1,250)
Increase (decrease) in cash and cash equivalents	(31)	76	(128)
Cash and cash equivalents, beginning of period	367	291	419
Cash and cash equivalents, end of period	$ 336	$ 367	$ 291

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)

1. OPERATIONS AND BASIS OF PRESENTATION:

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

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

- All of ETO's long-term debt was assumed by Energy Transfer, as more fully described in Note 6.
- Each issued and outstanding ETO preferred unit was converted into the right to receive one newly created Energy Transfer preferred unit. A description of the Energy Transfer Preferred Units is included in Note 8.
- Each of ETO's issued and outstanding Class K, Class L, Class M and Class N units were converted into an aggregate 675,625,000 newly created Class B Units representing limited partner interests in Energy Transfer. All of the Class B Units are held by ETP Holdco, a wholly-owned subsidiary of Energy Transfer.

Our financial statements reflect the following reportable segments:

- 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.

The Partnership owns and operates intrastate natural gas pipeline systems and storage facilities that are engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Oklahoma, Louisiana, New Mexico and West Virginia.

The Partnership owns and operates interstate pipelines, either directly or through equity method investments, that transport natural gas to various markets in the United States.

The Partnership is engaged in the gathering and processing, compression, treating and transportation of natural gas, focusing on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Granite Wash, SCOOP, STACK, Woodford, Fayetteville, Marcellus, Utica, Bone Spring and Avalon shales.

The Partnership owns and operates a logistics business, consisting of a geographically diverse portfolio of complementary pipeline, terminalling, and acquisition and marketing assets, which are used to facilitate the purchase and sale of crude oil, NGLs and refined products.

The Partnership owns a controlling interest in Sunoco LP which is engaged in the wholesale distribution of motor fuels to convenience stores, independent dealers, commercial customers, and distributors, as well as the retail sale of motor fuels and merchandise through Sunoco LP operated convenience stores and retail fuel sites. As of December 31, 2021, our interest in Sunoco LP consisted of 100% of the general partner and IDRs, as well as 28.5 million common units.

The Partnership owns a controlling interest in USAC which provides compression services to producers, processors, gatherers and transporters of natural gas and crude oil. As of December 31, 2021, our interest in USAC consisted of 100% of the general partner and 46.1 million common units.

Basis of Presentation. The consolidated financial statements of Energy Transfer LP presented herein for the years ended December 31, 2021, 2020 and 2019, have been prepared in accordance with GAAP and pursuant to the rules and regulations of the SEC. We consolidate all majority-owned subsidiaries and limited partnerships, which we control as the general partner or owner of the general partner. All significant intercompany transactions and accounts are eliminated in consolidation.

The consolidated financial statements of Energy Transfer presented herein include the results of operations of our controlled subsidiaries, including Sunoco LP and USAC.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream, NGL and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the estimated operating results represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Regulatory Accounting – Regulatory Assets and Liabilities

Our interstate transportation and storage segment is subject to regulation by certain state and federal authorities, and certain subsidiaries in that segment have accounting policies that conform to the accounting requirements and ratemaking practices of the regulatory authorities, in accordance with Accounting Standards Codification ("ASC") Topic 980. The application of these accounting policies allows certain of our regulated entities to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment under ASC Topic 980 for these entities, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of the FERC in accordance with the NGA and NGPA, Panhandle does not currently apply ASC Topic 980 in its GAAP-basis consolidated financial statements, primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

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

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

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

	Years Ended December 31,		
	2021	2020	2019
Accounts receivable	$ (3,356)	$ 1,163	$ (473)
Accounts receivable from related companies	38	(290)	(69)
Inventories	(19)	(271)	(19)
Other current assets	(216)	172	117
Other non-current assets, net	1	(7)	(102)
Accounts payable	3,834	(1,327)	146
Accounts payable to related companies	(34)	367	(32)
Accrued and other current liabilities	238	163	(44)
Other non-current liabilities	117	8	(133)
Derivative assets and liabilities, net	(88)	69	218
Net change in operating assets and liabilities, net of effects of acquisitions	$ 515	$ 47	$ (391)

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31,		
	2021	2020	2019
NON-CASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 464	$ 604	$ 1,334
Units issued in connection with the Enable Acquisition[(1)]	3,509	—	—
Lease assets obtained in exchange for new lease liabilities	18	42	68
Acquisition of interest in unconsolidated affiliate	49	—	—
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest, net of interest capitalized	$ 2,188	$ 2,092	$ 1,932
Cash paid for income taxes (net of refunds)	41	(64)	31

(1) See Note 3 for additional information.

Accounts Receivable

Our operations deal with a variety of counterparties across the energy sector. Internal credit ratings and credit limits are assigned to all counterparties and limits are monitored against credit exposure. Letters of credit or prepayments may be required from those counterparties that are not investment grade depending on the internal credit rating and level of commercial activity with the counterparty.

We have a diverse portfolio of customers; however, because of the midstream and transportation services we provide, many of our customers are engaged in the exploration and production segment. We manage trade credit risk to mitigate credit losses and exposure to uncollectible trade receivables. Prospective and existing customers are reviewed regularly for creditworthiness to manage credit risk within approved tolerances. Customers that do not meet minimum credit standards are required to provide additional credit support in the form of a letter of credit, prepayment, or other forms of security. We establish an allowance for credit losses on trade receivables based on the expected ultimate recovery of these receivables and consider many factors including historical customer collection experience, general and specific economic trends, and known specific issues related to individual customers, sectors, and transactions that might impact collectability. Changes in the allowance are recorded as a component of operating expenses; reductions in the allowance are recorded when receivables are subsequently collected or written-off. Past due receivable balances are written-off when our efforts have been unsuccessful in collecting the amount due.

Inventories

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

Sunoco LP’s fuel inventories are stated at the lower of cost or market using the last-in-first-out (“LIFO”) method. As of December 31, 2021 and 2020, Sunoco LP’s fuel inventory balance included lower of cost or market reserves of $121 million and $311 million, respectively. The fuel inventory balance is not materially different than its replacement cost at the respective dates. For the years ended December 31, 2021, 2020 and 2019, the Partnership’s consolidated statements of operations and comprehensive income did not include any material amounts of income from the liquidation of Sunoco LP’s LIFO fuel inventory. For the years ended December 31, 2021 and 2019, Sunoco LP’s cost of sales included favorable inventory adjustments of $190 million and $79 million, respectively, and for the year ended December 31, 2020, Sunoco LP’s cost of sales included a write-down of fuel inventory of $82 million.

The Partnership’s inventories consisted of the following:

	December 31,	
	2021	2020
Natural gas, NGLs and refined products	$ 1,259	$ 1,013
Crude oil	328	287
Spare parts and other	427	439
Total inventories	$ 2,014	$ 1,739

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

Other Current Assets

Other current assets consisted of the following:

	December 31,	
	2021	2020
Deposits paid to vendors	$ 215	$ 75
Prepaid expenses and other	222	138
Total other current assets	$ 437	$ 213

Property, Plant and Equipment

Property, plant and equipment is stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or FERC-mandated lives of the assets, if applicable. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment is retired or sold, any gain or loss is included in our consolidated statements of operations.

Property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value.

In 2021, USAC recognized a $5 million fixed asset impairment related to its compression equipment as a result of its evaluation of the future deployment of idle fleet.

In 2020, the Partnership recognized a $58 million fixed asset impairment primarily due to decreases in projected future cash flow as a result of the overall market demand decline. USAC recorded an $8 million impairment of compression equipment as a result of its evaluations of the future deployment of its idle fleet.

In 2019, USAC recognized a $6 million fixed asset impairment related to certain idle compressor assets. Sunoco LP recognized a $47 million write-down on assets held for sale related to its ethanol plant in Fulton, New York.

Capitalized interest is included for pipeline construction projects, except for certain interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facilities when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31,	
	2021	2020
Land and improvements	$ 1,369	$ 1,233
Buildings and improvements (1 to 45 years)	4,598	4,236
Pipelines and equipment (5 to 83 years)	77,112	69,120
Product storage and related facilities (2 to 83 years)	7,410	6,393
Right of way (20 to 83 years)	5,021	5,099
Other (1 to 48 years)	2,816	2,263
Construction work-in-process	5,665	5,771
	103,991	94,115
Less – Accumulated depreciation and depletion	(22,384)	(19,008)
Property, plant and equipment, net	$ 81,607	$ 75,107

We recognized the following amounts for the periods presented:

	Years Ended December 31,		
	2021	2020	2019
Depreciation, depletion and amortization expense	$ 3,465	$ 3,275	$ 2,839
Capitalized interest	135	189	166

Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for by the equity method. In general, we use the equity method of accounting for an investment for which we exercise significant influence over, but do not control, the investee's operating and financial policies. An impairment of an investment in an unconsolidated affiliate is recognized when circumstances indicate that a decline in the investment value is other than temporary. During the year ended December 31, 2020, the Partnership recorded an impairment of its investment in White Cliffs of $129 million due to a decrease in projected future revenues and cash flows as a result of the overall market demand decline that occurred subsequent to the SemGroup acquisition in December 2019.

Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2021	2020
Crude pipeline linefill and tank bottoms	$ 498	$ 517
Regulatory assets	42	41
Pension assets	140	103
Deferred charges	177	188
Restricted funds	164	179
Other	624	629
Total other non-current assets, net	$ 1,645	$ 1,657

Restricted funds include an immaterial amount of restricted cash primarily held in our wholly-owned captive insurance companies.

Intangible Assets

Intangible assets are stated at cost, net of amortization computed on the straight-line method. The Partnership removes the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized.

Components and useful lives of intangible assets were as follows:

	December 31, 2021		December 31, 2020	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 7,982	$ (2,464)	$ 7,513	$ (2,117)
Patents (10 years)	48	(44)	48	(40)
Trade names (20 years)	66	(38)	66	(35)
Other (5 to 20 years)	19	(20)	19	(15)
Total amortizable intangible assets	8,115	(2,566)	7,646	(2,207)
Non-amortizable intangible assets:				
Trademarks	295	—	295	—
Other	12	—	12	—
Total non-amortizable intangible assets	307	—	307	—
Total intangible assets	$ 8,422	$ (2,566)	$ 7,953	$ (2,207)

Aggregate amortization expense of intangible assets was as follows:

	Years Ended December 31,		
	2021	2020	2019
Reported in depreciation, depletion and amortization expense	$ 352	$ 403	$ 308

Estimated aggregate amortization of intangible assets for the next five years is as follows:

Years Ending December 31:	
2022	$ 379
2023	362
2024	348
2025	335
2026	331

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. The annual impairment test was performed during the fourth quarter.

Changes in the carrying amount of goodwill were 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	All Other	Total
Balance, December 31, 2019	$ 10	$ 226	$ 483	$ 693	$ 1,397	$ 1,555	$ 619	$ 184	$ 5,167
Acquired	—	—	—	—	—	9	—	—	9
Impaired	(10)	(226)	(483)	—	(1,279)	—	(619)	(198)	(2,815)
Other	—	—	—	—	(66)	—	—	96	30
Balance, December 31, 2020	—	—	—	693	52	1,564	—	82	2,391
Acquired	—	—	—	—	138	4	—	—	142
Balance, December 31, 2021	$ —	$ —	$ —	$ 693	$ 190	$ 1,568	$ —	$ 82	$ 2,533

As of December 31, 2021, the all other segment includes $72 million of goodwill allocated to a reporting unit that had a negative carrying value.

During the first quarter of 2020, due to the impacts of the COVID-19 pandemic, the decline in commodity prices and the decreases in the Partnership's market capitalization, we determined that interim impairment testing should be performed on certain reporting units. The Partnership performed the interim impairment tests consistent with our approach for annual impairment testing, including using similar models, inputs and assumptions. As a result of the interim impairment test, the Partnership recognized goodwill impairments of $483 million related to our Ark-La-Tex and South Texas operations within the midstream segment, $183 million related to our Lake Charles LNG regasification operations within the interstate transportation and storage segment due to contractually scheduled reductions in payments for the remainder of the contract term, and $40 million related to our all other operations primarily due to decreases in projected future revenues and cash flows as a result of the overall market demand decline. In addition, USAC recognized a goodwill impairment of $619 million during the three months ended March 31, 2020, which is included in the Partnership's consolidated results of operations.

During the third quarter of 2020, the Partnership performed interim impairment testing on certain reporting units within its midstream, interstate, crude, NGL and all other operations. As a result, the Partnership recognized goodwill impairments of $1.28 billion related to our crude operations, $132 million related to our Energy Transfer Canada operations within the all other segment and $43 million related to our interstate operations primarily due to decreases in projected future cash flow as a result of the overall market demand decline.

During the fourth quarter of 2020, the Partnership performed annual impairment testing on certain reporting units within its midstream, interstate, crude, NGL and all other operations. As a result, the Partnership recognized goodwill impairments of $10 million related to our intrastate operations, $11 million related to our PEI operations and $15 million related to our Natural Resources operations within the all other segment primarily due to decreases in projected future cash flow as a result of the overall market demand decline. No other impairments of the Partnership's goodwill were identified.

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized. During the fourth quarter of 2019, $265 million of goodwill was recorded in conjunction with the acquisition of SemGroup. During the fourth quarter of 2021, $138 million of goodwill was recorded in conjunction with the acquisition of Enable. In addition, Sunoco LP recorded $4 million of goodwill in conjunction with its acquisition of eight refined product terminals.

During the third quarter of 2019, the Partnership recognized a goodwill impairment of $12 million related to the Southwest Gas operations within the interstate segment primarily due to decreases in projected future revenues and cash flows. During the fourth quarter of 2019, the Partnership recognized a goodwill impairment of $9 million related to our North Central operations within the midstream segment primarily due to changes in assumptions related to projected future revenues and cash flows.

The Partnership determines the fair value of our reporting units using the discounted cash flow method, the guideline company method, or a weighted combination of the discounted cash flow method and the guideline company method. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The Partnership believes the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the Partnership determines fair value based on estimated future cash flows of each reporting unit including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflect the overall level of inherent risk of the reporting unit. Cash flow projections are derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which are evaluated by management. Subsequent period cash flows are developed for each reporting unit using growth rates that management believes are reasonably likely to occur. Under the guideline company method, the Partnership determines the estimated fair value of each of our reporting units by applying valuation multiples of comparable publicly-traded companies to each reporting unit's projected EBITDA and then averaging that estimate with similar historical calculations using a three year average. In addition, the Partnership estimates a reasonable control premium representing the incremental value that accrues to the majority owner from the opportunity to dictate the strategic and operational actions of the business. The fair value estimates used in the long-lived asset and goodwill tests were primarily based on Level 3 inputs of the fair value hierarchy.

Asset Retirement Obligations

We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. The fair value of any ARO is determined based on estimates and assumptions related to retirement costs, which the Partnership bases on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. These fair value assessments are considered to be Level 3 measurements, as they are based on both observable and unobservable inputs. Changes in the liability are recorded for the passage of time (accretion) or for revisions to cash flows originally estimated to settle the ARO.

An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. We will record an ARO in the periods in which management can reasonably estimate the settlement dates.

As of December 31, 2021 and 2020, other non-current liabilities in the Partnership's consolidated balance sheets included AROs of $369 million and $280 million, respectively. For the years ended December 31, 2021, 2020 and 2019 aggregate accretion expense related to AROs was $12 million, $16 million and $5 million, respectively.

Except for the AROs discussed above, management was not able to reasonably measure the fair value of AROs as of December 31, 2021 and 2020, in most cases because the settlement dates were indeterminable. Although a number of onshore assets in our systems are subject to agreements or regulations that give rise to an ARO upon discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement. Our subsidiaries also have legal obligations for several other assets at previously owned refineries, pipelines and terminals, for which it is not possible to estimate when the obligations will be settled. Consequently, the retirement obligations for these assets cannot be measured at this time. At the end of the useful life of these underlying assets, our subsidiaries are legally or contractually required to abandon in place or remove the asset. We believe we may have additional AROs related to pipeline assets and storage tanks, for which it is not possible to estimate whether or when the AROs will be settled. Consequently, these AROs cannot be measured at this time. Sunoco LP also has AROs related to the estimated future cost to remove underground storage tanks.

Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. We have in place a rigorous repair and maintenance program that keeps the pipelines and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets may be replaced, the pipelines and the natural gas gathering and processing systems themselves will remain intact indefinitely.

As of December 31, 2021 and 2020, other non-current assets on the Partnership's consolidated balance sheets included $39 million and $34 million, respectively, of funds that were legally restricted for the purpose of settling AROs.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31,	
	2021	2020
Interest payable	$ 561	$ 600
Customer advances and deposits	188	161
Accrued capital expenditures	461	604
Accrued wages and benefits	297	109
Taxes payable other than income taxes	384	446
Exchanges payable	155	127
Deferred revenue	158	112
Other	867	616
Total accrued and other current liabilities	$ 3,071	$ 2,775

Customer advances and deposits are received from our customers as prepayments for natural gas deliveries in the following month. Prepayments and security deposits may be required when customers exceed their credit limits or do not qualify for open credit.

Redeemable Noncontrolling Interests

Our redeemable noncontrolling interests relate to certain preferred unitholders of one of our consolidated subsidiaries that have the option to convert their preferred units to such subsidiary's common units at the election of the holders and the noncontrolling interest holders in one of our consolidated subsidiaries that have the option to sell their interests to us. In accordance with applicable accounting guidance, the noncontrolling interest is excluded from total equity and reflected as redeemable noncontrolling interests on our consolidated balance sheets. See Note 7 for further information.

Environmental Remediation

We accrue environmental remediation costs for work at identified sites where an assessment has indicated that cleanup costs are probable and reasonably estimable. Such accruals are undiscounted and are based on currently available information, estimated timing of remedial actions and related inflation assumptions, existing technology and presently enacted laws and regulations. If a range of probable environmental cleanup costs exists for an identified site, the minimum of the range is accrued unless some other point in the range is more likely in which case the most likely amount in the range is accrued.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value.

We have commodity derivatives, interest rate derivatives and embedded derivatives in our preferred units that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider OTC commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. During the year ended December 31, 2021, no transfers were made between any levels within the fair value hierarchy.

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

	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)

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

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2021 was $54.97 billion and $49.70 billion, respectively. As of December 31, 2020, the aggregate fair value and carrying amount of our debt obligations was $56.21 billion and $51.44 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs (“CIAC”) are netted against our project costs as they are received.

Shipping and Handling Costs

Shipping and handling costs are included in cost of products sold, except for shipping and handling costs related to fuel consumed for compression and treating which are included in operating expenses.

Costs and Expenses

Cost of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis, except for consumer excise taxes collected by Sunoco LP on sales of refined products and merchandise which are included in both revenues and costs and expenses in the consolidated statements of operations, with no effect on net income. For the years ended December 31, 2021, 2020 and 2019, excise taxes collected by Sunoco LP were $332 million, $301 million and $386 million, respectively.

Issuances of Subsidiary Units

We record changes in our ownership interest of our subsidiaries as equity transactions, with no gain or loss recognized in consolidated net income or comprehensive income. For example, upon our subsidiary's issuance of common units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the noncontrolling interests are adjusted as a change in partners' capital.

Related Party Transactions

The Partnership regularly enters into related party transactions with several of its unconsolidated affiliates. In addition to commercial transactions, these transactions include the provision of certain management services and leases of certain assets. While the Partnership believes that such related party transactions generally reflect market rates, the pricing under such agreements may not be comparable to similar transactions with unaffiliated third parties. For the years ended December 31, 2021, 2020 and 2019, the Partnership's consolidated income statements reflect revenues from related parties of $410 million, $466 million and $492 million, respectively.

Income Taxes

Energy Transfer is a publicly traded limited partnership and is not taxable for federal and most state income tax purposes. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and most state purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under our Third Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement"). We do not have access to information regarding each partner's individual tax basis in our limited partner interests.

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and IRS pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, Energy Transfer would be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2021, 2020 and 2019, our qualifying income met the statutory requirement.

The Partnership conducts certain activities through corporate subsidiaries which are subject to federal, state and local income taxes. These corporate subsidiaries include ETP Holdco, Inland Corporation, Sunoco Retail LLC and Aloha. The Partnership and its corporate subsidiaries account for income taxes under the asset and liability method.

Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third-party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a commodity hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statements of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statements of operations.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on interest rate derivatives" in the consolidated statements of operations.

Equity Incentive Compensation

For awards of restricted units, we recognize compensation expense over the vesting period based on the grant-date fair value, which is determined based on the market price of the underlying common units on the grant date. For awards of cash restricted units, we remeasure the fair value of the award at the end of each reporting period based on the market price of the underlying common units as of the reporting date, and the fair value is recorded in other non-current liabilities on our consolidated balance sheets.

Pensions and Other Postretirement Benefit Plans

The Partnership recognizes the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Changes in the funded status of the plan are recorded in the year in which the change occurs within AOCI in equity or, for entities applying regulatory accounting, as a regulatory asset or regulatory liability.

Allocation of Income

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests.

3. ACQUISITIONS, DIVESTITURES AND RELATED TRANSACTIONS:

Enable Acquisition

On December 2, 2021, the Partnership completed the previously announced merger with Enable (the "Enable Acquisition"). Under the terms of the merger agreement, Enable's common unitholders received 0.8595 of an Energy Transfer common unit in exchange for each Enable common unit. In addition, each outstanding Enable Series A preferred unit was exchanged for 0.0265 of an Energy Transfer Series G Preferred Unit. A total of 384,780 Series G Preferred Units were issued in connection with the Enable Acquisition. The total fair value of Energy Transfer common units and Series G Preferred Units issued was approximately $3.5 billion at the closing date. Energy Transfer also made a $10 million cash payment for Enable's general partner and assumed $3.18 billion aggregate principal amount of Enable senior notes. In addition, Enable's $800 million term loan and $35 million revolving credit facility were repaid and terminated in December 2021, immediately subsequent to the close of the Enable Acquisition.

The Enable Acquisition was recorded using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their estimated fair values on the date of acquisition with any excess purchase price over the fair value of net assets acquired recorded to goodwill. Determining the fair value of acquired assets requires management's judgment and the utilization of an independent valuation specialist, if applicable, and involves the use of significant estimates and assumptions. Acquired assets were valued based on a combination of the discounted cash flow, the guideline company and the reproduction and replacement methods. The purchase price allocation below is preliminary, as management is currently evaluating certain assumptions and may adjust the allocation in the subsequent period.

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

	At December 2, 2021
Total current assets	$ 593
Property, plant and equipment, net	7,076
Investments in unconsolidated affiliates	40
Other non-current assets	39
Intangible assets, net	440
Goodwill	138
Total assets	8,326
Total current liabilities	488
Long-term debt, less current maturities[(1)]	4,267
Other non-current liabilities	18
Total liabilities	4,773
Noncontrolling interests	34
Total consideration	3,519
Cash received	61
Total consideration	$ 3,458

(1) Long-term debt at December 2, 2021 includes Enable senior notes with an aggregate principal amount of $3.18 billion in senior notes and a fair value of $3.43 billion. It also includes $800 million outstanding on the Enable 2019 Term Loan Agreement and $35 million outstanding on the Enable Five-Year Revolving Credit Facility, both of which were repaid and terminated in December 2021, immediately subsequent to the close of the Enable Acquisition.

SemGroup Acquisition and Energy Transfer Contribution of SemGroup Assets to ETO

On December 5, 2019, Energy Transfer completed the acquisition of SemGroup pursuant to the terms of the Agreement and Plan of Merger, dated as of September 15, 2019 (the "SemGroup Merger Agreement"). Under the terms of the SemGroup Merger Agreement, a wholly owned subsidiary of Energy Transfer merged with and into SemGroup (the "SemGroup Transaction"), with SemGroup surviving the merger. At the effective time of the SemGroup Transaction on

December 5, 2019, each share of class A common stock, par value $0.01 per share, of SemGroup issued and outstanding immediately prior to the effective time was converted into the right to receive (i) $6.80 in cash, without interest, and (ii) 0.7275 Energy Transfer Common Units representing limited partner interests in Energy Transfer. Each share of Series A Cumulative Perpetual Convertible Preferred Stock, par value $0.01 per share, of SemGroup that was issued and outstanding as of immediately prior to the effective time was redeemed by SemGroup for cash at a price per share equal to 101% of the liquidation preference.

During the first and second quarters of 2020, Energy Transfer contributed former SemGroup assets to ETO through sale and contribution transactions. The following table represents the fair value, as of December 5, 2019, of the SemGroup assets and liabilities transferred from Energy Transfer to ETO:

	At December 5, 2019
Total current assets	$ 794
Property, plant and equipment	3,891
Other non-current assets	617
Goodwill	295
Intangible assets	460
Total assets	$ 6,057
Total current liabilities	$ 629
Long-term debt, less current maturities (1)	2,576
Other non-current liabilities	197
Energy Transfer Canada Preferred shares	241
Total liabilities	3,643
Noncontrolling interest	822
Partners’ capital	1,592
Total liabilities and partners’ capital	$ 6,057

(1) Long-term debt at December 5, 2019 includes SemGroup senior notes with an aggregate principal amount of $1.375 billion and SemGroup subsidiary debt of $593 million, all of which was redeemed in December 2019, subsequent to the close of the SemGroup Transaction.

During 2020, the Partnership has recorded impairments on certain of the contributed SemGroup assets. Those impairments include a $244 million impairment of goodwill and a $129 million impairment of other non-current assets.

4. INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Citrus

CrossCountry Energy, LLC, a wholly-owned subsidiary of Energy Transfer, owns a 50% interest in Citrus. Citrus owns 100% of FGT, an approximately 5,362-mile natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula. Our investment in Citrus is reflected in our interstate transportation and storage segment.

FEP

Energy Transfer has a 50% interest in FEP which owns the Fayetteville Express Pipeline, an approximately 185-mile natural gas pipeline that originates in Conway County, Arkansas, continues eastward through White County, Arkansas and terminates at an interconnect with Trunkline in Panola County, Mississippi. Energy Transfer’s investment in FEP is reflected in the interstate transportation and storage segment.

MEP

Energy Transfer owns a 50% interest in MEP, which owns the Midcontinent Express Pipeline, an approximately 500-miles natural gas pipeline that extends from Southeast Oklahoma, across Northeast Texas, Northern Louisiana and Central

Mississippi to an interconnect with the Transcontinental natural gas pipeline system in Butler, Alabama. Energy Transfer's investment in MEP is reflected in the interstate transportation and storage segment.

White Cliffs

We own a 51% interest in White Cliffs, which was acquired by Energy Transfer in the SemGroup acquisition. White Cliffs consists of two parallel, 12-inch common carrier pipelines: one crude oil pipeline and one NGL pipeline. These pipelines transport crude and NGLs from Platteville, Colorado to Cushing, Oklahoma. The Partnership recorded an impairment of its investment in White Cliffs of $129 million during the year ended December 31, 2020 due to a decrease in projected future revenues and cash flows as a result of the overall market demand decline that occurred subsequent to the SemGroup acquisition and related purchase price allocation in December 2019.

The carrying values of the Partnership's investments in unconsolidated affiliates as of December 31, 2021 and 2020 were as follows:

	December 31,	
	2021	2020
Citrus	$ 1,792	$ 1,867
FEP	—	4
MEP	378	406
White Cliffs	245	274
Other	532	509
Total	$ 2,947	$ 3,060

The following table presents equity in earnings (losses) of unconsolidated affiliates:

	Years Ended December 31,		
	2021	2020	2019
Citrus	$ 157	$ 162	$ 148
FEP [(1)]	—	(139)	59
MEP	(17)	(6)	15
White Cliffs	—	20	4
Other	106	82	76
Total equity in earnings of unconsolidated affiliates	$ 246	$ 119	$ 302

(1) For the year ended December 31, 2020, equity in earnings (losses) of unconsolidated affiliates includes the impact of non-cash impairments recorded by FEP, which reduced the Partnership's equity in earnings by $208 million.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, Citrus, FEP, MEP, and White Cliffs (on a 100% basis) for all periods presented:

	December 31,	
	2021	2020
Current assets	$ 242	$ 227
Property, plant and equipment, net	7,239	7,339
Other assets	77	58
Total assets	$ 7,558	$ 7,624
Current liabilities	$ 500	$ 600
Non-current liabilities	3,602	3,298
Equity	3,456	3,726
Total liabilities and equity	$ 7,558	$ 7,624

	Years Ended December 31,		
	2021	2020	2019
Revenue	$ 1,003	$ 1,243	$ 1,192
Operating income	459	6	683
Net income (loss)	282	(199)	443

In addition to the equity method investments described above we have other equity method investments which are not significant to our consolidated financial statements.

5. NET INCOME PER LIMITED PARTNER UNIT:

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding. Diluted net income per limited partner unit is computed by dividing net income (as adjusted as discussed herein), after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding. For the diluted earnings per share computation, income allocable to the limited partners is reduced, where applicable, for the decrease in earnings from Energy Transfer's limited partner unit ownership in Sunoco LP that would have resulted assuming the incremental units related to Sunoco LP's equity incentive plans, as applicable, had been issued during the respective periods. Such units have been determined based on the treasury stock method.

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

	Years Ended December 31,		
	2021	2020	2019
Net income	$ 6,687	$ 140	$ 4,825
Less: Net income attributable to redeemable noncontrolling interests	50	49	51
Less: Net income attributable to noncontrolling interests	1,167	739	1,256
Net income (loss), net of noncontrolling interests	5,470	(648)	3,518
Less: General Partner's interest in income (loss)	6	(1)	4
Less: Preferred Unitholders' interest in income	285	—	—
Income (loss) available to Limited Partners	$ 5,179	$ (647)	$ 3,514
Basic Income (Loss) per Limited Partner Unit:			
Weighted average limited partner units	2,734.4	2,695.6	2,628.0
Basic income (loss) per Limited Partner unit	$ 1.89	$ (0.24)	$ 1.34
Diluted Income (Loss) per Limited Partner Unit:			
Income (loss) available to Limited Partners	$ 5,179	$ (647)	$ 3,514
Dilutive effect of equity-based compensation of subsidiaries and distributions to convertible units	(2)	—	(1)
Diluted income (loss) available to Limited Partners	$ 5,177	$ (647)	$ 3,513
Weighted average limited partner units	2,734.4	2,695.6	2,628.0
Dilutive effect of unvested unit awards	5.1	—	9.6
Weighted average limited partner units, assuming dilutive effect of unvested unit awards	2,739.5	2,695.6	2,637.6
Diluted income (loss) per Limited Partner unit	$ 1.89	$ (0.24)	$ 1.33

6. DEBT OBLIGATIONS:

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

In connection with the Enable Acquisition on December 2, 2021, as discussed in Note 3, Energy Transfer repaid $800 million outstanding on the Enable 2019 Term Loan Agreement and $35 million outstanding on the Enable Five-Year Revolving Credit Facility, and both facilities were terminated. In addition, the Partnership assumed $3.18 billion aggregate principal amount of Enable senior notes.

Our debt obligations consist of the following:

	December 31,	
	2021	2020
Energy Transfer Indebtedness		
4.40% Senior Notes due April 1, 2021[1]	$ —	$ 600
4.65% Senior Notes due June 1, 2021[1]	—	800
5.20% Senior Notes due February 1, 2022[1]	—	1,000
4.65% Senior Notes due February 15, 2022[2]	300	300
5.875% Senior Notes due March 1, 2022[1]	—	900
5.00% Senior Notes due October 1, 2022[2]	700	700
3.45% Senior Notes due January 15, 2023	350	350
3.60% Senior Notes due February 1, 2023	800	800
4.25% Senior Notes due March 15, 2023	5	5
4.25% Senior Notes due March 15, 2023	995	995
4.20% Senior Notes due September 15, 2023	500	500
4.50% Senior Notes due November 1, 2023	600	600
5.875% Senior Notes due January 15, 2024	23	23
5.875% Senior Notes due January 15, 2024	1,127	1,127
4.90% Senior Notes due February 1, 2024	350	350
7.60% Senior Notes due February 1, 2024	277	277
4.25% Senior Notes due April 1, 2024	500	500
4.50% Senior Notes due April 15, 2024	750	750
3.90% Senior Notes due May 15, 2024[3]	600	—
9.00% Debentures due November 1, 2024	65	65
4.05% Senior Notes due March 15, 2025	1,000	1,000
2.90% Senior Notes due May 15, 2025	1,000	1,000
5.95% Senior Notes due December 1, 2025	400	400
4.75% Senior Notes due January 15, 2026	1,000	1,000
3.90% Senior Notes due July 15, 2026	550	550
4.40% Senior Notes due March 15, 2027[3]	700	—
4.20% Senior Notes due April 15, 2027	600	600
5.50% Senior Notes due June 1, 2027	44	44
5.50% Senior Notes due June 1, 2027	956	956
4.00% Senior Notes due October 1, 2027	750	750
4.95% Senior Notes due May 15, 2028[3]	800	—
4.95% Senior Notes due June 15, 2028	1,000	1,000
5.25% Senior Notes due April 15, 2029	1,500	1,500
4.15% Senior Notes due September 15, 2029[3]	547	—
8.25% Senior Notes due November 15, 2029	267	267
3.75% Senior Note due May 15, 2030	1,500	1,500
4.90% Senior Notes due March 15, 2035	500	500

6.625% Senior Notes due October 15, 2036	400	400
5.80% Senior Notes due June 15, 2038	500	500
7.50% Senior Notes due July 1, 2038	550	550
6.85% Senior Notes due February 15, 2040	250	250
6.05% Senior Notes due June 1, 2041	700	700
6.50% Senior Notes due February 1, 2042	1,000	1,000
6.10% Senior Notes due February 15, 2042	300	300
4.95% Senior Notes due January 15, 2043	350	350
5.15% Senior Notes due February 1, 2043	450	450
5.95% Senior Notes due October 1, 2043	450	450
5.30% Senior Notes due April 1, 2044	700	700
5.00% Senior Notes due May 15, 2044(3)	531	—
5.15% Senior Notes due March 15, 2045	1,000	1,000
5.35% Senior Notes due May 15, 2045	800	800
6.125% Senior Notes due December 15, 2045	1,000	1,000
5.30% Senior Notes due April 15, 2047	900	900
5.40% Senior Notes due October 1, 2047	1,500	1,500
6.00% Senior Notes due June 15, 2048	1,000	1,000
6.25% Senior Notes due April 15, 2049	1,750	1,750
5.00% Senior Notes due May 15, 2050	2,000	2,000
Floating Rate Junior Subordinated Notes due November 1, 2066	546	546
Term Loan	—	2,000
Five-Year Credit Facility	2,937	3,103
Unamortized premiums, discounts and fair value adjustments, net	233	(17)
Deferred debt issuance costs	(186)	(215)
	40,717	42,726
Subsidiary Indebtedness		
Transwestern Debt		
5.89% Senior Notes due May 24, 2022(2)	150	150
5.66% Senior Notes due December 9, 2024	175	175
6.16% Senior Notes due May 24, 2037	75	75
	400	400
Panhandle Debt		
7.60% Senior Notes due February 1, 2024	82	82
7.00% Senior Notes due July 15, 2029	66	66
8.25% Senior Notes due November 15, 2029	33	33
Floating Rate Junior Subordinated Notes due November 1, 2066	54	54
Unamortized premiums, discounts and fair value adjustments, net	8	10
	243	245
Bakken Project Debt		
3.625% Senior Notes due April 1, 2022	650	650
3.90% Senior Notes due April 1, 2024	1,000	1,000
4.625% Senior Notes due April 1, 2029	850	850
Unamortized premiums, discounts and fair value adjustments, net	(2)	(3)
Deferred debt issuance costs	(9)	(13)
	2,489	2,484

Sunoco LP Debt		
4.875% Senior Notes Due January 15, 2023	—	436
5.50% Senior Notes Due February 15, 2026	—	800
6.00% Senior Notes Due April 15, 2027	600	600
5.875% Senior Notes Due March 15, 2028	400	400
4.50% Senior Notes due May 15, 2029	800	800
4.50% Senior Notes due April 30, 2030	800	—
Sunoco LP $1.50 billion Revolving Credit Facility due July 2023	581	—
Lease-related obligations	100	103
Deferred debt issuance costs	(26)	(27)
	3,255	3,112
USAC Debt		
6.875% Senior Notes due April 1, 2026	725	725
6.875% Senior Notes due September 1, 2027	750	750
USAC $1.60 billion Revolving Credit Facility due December 2026	516	474
Deferred debt issuance costs	(18)	(22)
	1,973	1,927
HFOTCO Debt		
HFOTCO Tax Exempt Notes due 2050	225	225
Unamortized premiums, discounts and fair value adjustments, net	(1)	(2)
	224	223
Energy Transfer Canada Debt		
Energy Transfer Canada Revolving Credit Facility	7	57
Energy Transfer Canada Term Loan A	249	261
Energy Transfer Canada KAPS Facility	142	—
	398	318
Other	3	3
Total debt	49,702	51,438
Less: Current maturities of long-term debt	680	21
Long-term debt, less current maturities	$ 49,022	$ 51,417

(1) These notes were redeemed in 2021.

(2) As of December 31, 2021, these notes were classified as long-term as management had the intent and ability to refinance the borrowings on a long-term basis. The $300 million principal amount of 4.65% Senior Notes were redeemed in February 2022 using proceeds from Energy Transfer's Five-Year Credit Facility.

(3) These notes were assumed by Energy Transfer in connection with the Enable Acquisition.

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $1 million in unamortized premiums, fair value adjustments and deferred debt issuance costs, net:

2022	$ 1,827
2023	3,859
2024	8,250
2025	2,407
2026	2,799
Thereafter	30,561
Total	$ 49,703

Long-term debt reflected on our consolidated balance sheets includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap.

Notes and Debentures

Senior Notes

As discussed in Note 1, beginning on April 1, 2021 as a result of the Rollup Mergers, Energy Transfer assumed the obligations of the ETO senior notes. The ETO senior notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETO senior notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETO senior notes. The balance is payable upon maturity. Interest on the ETO senior notes is paid semi-annually.

The Energy Transfer Senior Notes are the Partnership’s senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of its future subordinated debt. Energy Transfer’s obligations under the Energy Transfer Senior Notes previously were secured on a first-priority basis with its obligations under the Revolver Credit Agreement and the Energy Transfer Term Loan Facility, by a lien on substantially all of Energy Transfer’s and certain of its subsidiaries’ tangible and intangible assets, subject to certain exceptions and permitted liens. Subsequent to the termination of the Revolver Credit Agreement and the Energy Transfer Term Loan Facility, the collateral securing the Energy Transfer Senior Notes was released. The Energy Transfer Senior Notes are not guaranteed by any of its subsidiaries.

The covenants related to the Energy Transfer Senior Notes include a limitation on liens, a limitation on transactions with affiliates, a restriction on sale-leaseback transactions and limitations on mergers and sales of all or substantially all of the Partnership’s assets.

Transwestern Senior Notes

The Transwestern senior notes are redeemable at any time in whole or pro rata, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

Sunoco LP Senior Notes

On October 20, 2021, Sunoco LP completed a private offering of $800 million in aggregate principal amount of 4.50% senior notes due 2030 (the “2030 Notes”). Sunoco LP used the proceeds from the private offering to fund a tender offer and repurchase all of its senior notes due 2026.

On November 9, 2020, Sunoco LP completed a private offering of $800 million in aggregate principal amount of 4.50% senior notes due 2029. Sunoco LP used the proceeds to fund the tender offer on its 4.875% $1 billion senior notes due 2023. Approximately 56% of the 2023 senior notes were tendered. On January 15, 2021, Sunoco LP repurchased the remaining outstanding portion of its 2023 senior notes.

Term Loans, Credit Facilities and Commercial Paper

Term Loan

As a result of the Rollup Mergers, on April 1, 2021, Energy Transfer assumed all of ETO’s obligations in respect of its term loan credit agreement, and the facility was subsequently repaid and terminated.

Five-Year Credit Facility

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

As of December 31, 2021, the Five-Year Credit Facility had $2.94 billion of outstanding borrowings, of which $1.19 billion consisted of commercial paper. The amount available for future borrowings was $2.03 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 December 31, 2021 was 1.13%.

364-Day Facility

As a result of the Rollup Mergers, on April 1, 2021, Energy Transfer assumed all of ETO's obligations in respect of its 364-day revolving credit facility, and the facility was subsequently terminated.

Sunoco LP Credit Facility

Sunoco LP maintains a $1.50 billion revolving credit facility (the "Sunoco LP Credit Facility"). As of December 31, 2021, the Sunoco LP Credit Facility had $581 million outstanding borrowings and $6 million in standby letters of credit and matures in July 2023. The amount available for future borrowings was $913 million at December 31, 2021. The weighted average interest rate on the total amount outstanding as of December 31, 2021 was 2.10%.

USAC Credit Facility

USAC maintains a $1.60 billion revolving credit facility (the "USAC Credit Facility"), which, as amended in December 2021, matures on December 8, 2026, except that if any portion of USAC's senior notes due 2026 are outstanding on December 31, 2025, the USAC Credit Facility will mature on December 31, 2025. The USAC Credit Facility also permits up to $200 million of future increases in borrowing capacity. As of December 31, 2021, USAC had $516 million of outstanding borrowings and no outstanding letters of credit under the credit agreement. As of December 31, 2021, USAC had $1.1 billion of availability under its credit facility, and subject to compliance with applicable financial covenants, available borrowing capacity of $262 million. The weighted average interest rate on the total amount outstanding as of December 31, 2021 was 2.68%.

Energy Transfer Canada Credit Facilities

Energy Transfer Canada is party to a credit agreement providing for a C$350 million (US$276 million at the December 31, 2021 exchange rate) senior secured term loan facility (the "Energy Transfer Canada Term Loan A"), a C$525 million (US$414 million at the December 31, 2021 exchange rate) senior secured revolving credit facility (the "Energy Transfer Canada Revolving Credit Facility"), and a C$300 million (US$237 million at the December 31, 2021 exchange rate) senior secured construction loan facility (the "Energy Transfer Canada KAPS Facility"). The Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility mature on February 25, 2024. The Energy Transfer Canada KAPS Facility matures on June 13, 2024. Energy Transfer Canada may incur additional term loans and revolving commitments in an aggregate amount not to exceed C$250 million (US$197 million at the December 31, 2021 exchange rate), subject to receiving commitments for such additional term loans or revolving commitments from either new lenders or increased commitments from existing lenders. As of December 31, 2021, the Energy Transfer Canada Term Loan A and the Energy Transfer Canada Revolving Credit Facility had outstanding borrowings of C$315 million and C$9 million, respectively (US$249 million and US$7 million, respectively, at the December 31, 2021 exchange rate). As of December 31, 2021, the KAPS Facility had outstanding borrowings of C$179 million (US$142 million at the December 31, 2021 exchange rate).

Covenants Related to Our Credit Agreements

The agreements relating to the Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions.

The Five-Year Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;

- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in the Five-Year Credit Facility) during certain Defaults (as defined in the Five-Year Credit Facility) and during any Event of Default (as defined in the Five-Year Credit Facility);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements.

The applicable margin and rate used in connection with the interest rates and commitment fees, respectively, are based on the credit ratings assigned to our senior, unsecured, non-credit enhanced long-term debt. The applicable margin for eurodollar rate loans under the Five-Year Credit Facility ranges from 1.125% to 2.000% and the applicable margin for base rate loans ranges from 0.125% to 1.000%. The applicable rate for commitment fees under the Five-Year Credit Facility ranges from 0.125% to 0.300%.

The Five-Year Credit Facility contains various covenants including limitations on the creation of indebtedness and liens and related to the operation and conduct of our business. The Five-Year Credit Facility also limits us, on a rolling four quarter basis, to a maximum Consolidated Funded Indebtedness to Consolidated EBITDA ratio, as defined in the underlying credit agreement, of 5.0 to 1, which can generally be increased to 5.5 to 1 during a Specified Acquisition Period. Our Leverage Ratio was 3.07 to 1 at December 31, 2021, as calculated in accordance with the credit agreement.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Partnership's or our subsidiaries' ability to incur additional debt and/or our ability to pay distributions to Unitholders.

Covenants Related to Transwestern

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

Covenants Related to Panhandle

Panhandle is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of Panhandle's lending agreements.

Panhandle's restrictive covenants include restrictions on liens securing debt and guarantees and restrictions on mergers and on the sales of assets. A breach of any of these covenants could result in acceleration of Panhandle's debt.

Covenants Related to Sunoco LP

The Sunoco LP Credit Facility contains various customary representations, warranties, covenants and events of default, including a change of control event of default, as defined therein. Sunoco LP's Credit Facility requires Sunoco LP to maintain a Net Leverage Ratio of not more than 5.5 to 1. The maximum Net Leverage Ratio is subject to upwards adjustment of not more than 6.0 to 1 for a period not to exceed three fiscal quarters in the event Sunoco LP engages in certain specified acquisitions of not less than $50 million (as permitted under Sunoco LP's Credit Facility agreement). The Sunoco LP Credit Facility also requires Sunoco LP to maintain an Interest Coverage Ratio (as defined in the Sunoco LP's Credit Facility agreement) of not less than 2.25 to 1.

Covenants Related to USAC

The USAC Credit Facility contains covenants that limit (subject to certain exceptions) USAC's ability to, among other things:

- grant liens;

- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- enter into transactions with affiliates;
- merge or consolidate;
- sell our assets; and
- make certain acquisitions.

The credit facility is also subject to the following financial covenants, including covenants requiring USAC to maintain:

- a minimum EBITDA to interest coverage ratio of 2.5 to 1.0, determined as of the last day of each fiscal quarter, with EBITDA and interest expense annualized for the fiscal quarter most recently ended;
- a ratio of total secured indebtedness to EBITDA not greater than 3.0 to 1.0 or less than 0.0 to 1.0, determined as of the last day of each fiscal quarter, with EBITDA annualized for the fiscal quarter most recently ended; and
- a maximum funded debt to EBITDA ratio, determined as of the last day of each fiscal quarter with EBITDA annualized for the fiscal quarter most recently ended, (i) 5.75 to 1 through the second fiscal quarter of 2022, (ii) 5.5 to 1 from the third quarter of 2022 through the third quarter of 2023, and (iii) 5.25 to 1 thereafter. In addition, USAC may increase the applicable ratio by 0.25 for any fiscal quarter during which a Specified Acquisition (as defined in the Credit Agreement) occurs and the following two fiscal quarters, but in no event shall the maximum ratio exceed 5.5 to 1.0 for any fiscal quarter as a result of such increase.

Covenants Related to the HFOTCO Tax Exempt Notes

The indentures covering HFOTCO's tax exempt notes due 2050 ("IKE Bonds") include customary representations and warranties and affirmative and negative covenants. Such covenants include limitations on the creation of new liens, indebtedness, making of certain restricted payments and payments on indebtedness, making certain dispositions, making material changes in business activities, making fundamental changes including liquidations, mergers or consolidations, making certain investments, entering into certain transactions with affiliates, making amendments to certain credit or organizational agreements, modifying the fiscal year, creating or dealing with hazardous materials in certain ways, entering into certain hedging arrangements, entering into certain restrictive agreements, funding or engaging in sanctioned activities, taking actions or causing the trustee to take actions that materially adversely affect the rights, interests, remedies or security of the bondholders, taking actions to remove the trustee, making certain amendments to the bond documents, and taking actions or omitting to take actions that adversely impact the tax exempt status of the IKE Bonds.

Compliance with our Covenants

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities and note agreements could require us or our subsidiaries to pay debt balances prior to scheduled maturity and could negatively impact the subsidiaries ability to incur additional debt and/or our ability to pay distributions.

We and our subsidiaries were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2021.

7. REDEEMABLE NONCONTROLLING INTERESTS:

Certain redeemable noncontrolling interests in the Partnership's subsidiaries are reflected as mezzanine equity on the consolidated balance sheet. Redeemable noncontrolling interests as of December 31, 2021 included a balance of $477 million related to the USAC Preferred Units described below and a balance of $15 million related to noncontrolling interest holders in one of the Partnership's consolidated subsidiaries that have the option to sell their interests to the Partnership. In addition, redeemable noncontrolling interests includes a balance of $291 million of Energy Transfer Canada preferred shares.

USAC Series A Preferred Units

As of December 31, 2021, USAC had 500,000 preferred units issued and outstanding. The USAC Preferred Units are entitled to receive cumulative quarterly distributions equal to $24.375 per USAC Preferred Unit, subject to increase in certain limited circumstances. The USAC Preferred Units will have a perpetual term, unless converted or redeemed. Certain portions of the USAC Preferred Units are convertible into USAC common units at the election of the holders. To the extent the holders of the USAC Preferred Units have not elected to convert their preferred units by the fifth anniversary of the issue date, USAC will have the option to redeem all or any portion of the USAC Preferred Units for cash. In addition, beginning April 2028, the holders of the USAC Preferred Units will have the right to require USAC to redeem all or any portion of the USAC Preferred Units, and the Partnership may elect to pay up to 50% of such redemption amount in USAC common units.

Energy Transfer Canada Redeemable Preferred Stock

Energy Transfer Canada has 300,000 shares of cumulative preferred stock issued and outstanding. The preferred stock is redeemable at Energy Transfer Canada's option subsequent to January 3, 2021 at a redemption price of C$1,100 (US$868 at the December 31, 2021 exchange rate) per share. The preferred stock is redeemable by the holder contingent upon a change of control or liquidation of Energy Transfer Canada. The preferred stock is convertible to Energy Transfer Canada common shares in the event of an initial public offering by Energy Transfer Canada.

Dividends on the preferred stock are payable in-kind through the quarter ending June 30, 2021. The dividends paid-in-kind increased the liquidation preference such that as of December 31, 2021, the preferred stock was convertible into 367,521 shares.

For the quarter ended December 31, 2021, Energy Transfer Canada declared cash dividends of C$8 million (US$6 million at the December 31, 2021 exchange rate) on the preferred stock that will be paid in the first quarter of 2022.

8. EQUITY:

Limited Partner Units

Limited partner interests in the Partnership are represented by Common Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. The Partnership's Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than the Partnership's General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash."

As of December 31, 2021, there were issued and outstanding 3.08 billion Common Units representing an aggregate 99.9% limited partner interest in the Partnership.

Our Partnership Agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. For any fiscal year that the Partnership has net profits, such net profits are first allocated to the General Partner until the aggregate amount of net profits for the current and all prior fiscal years equals the aggregate amount of net losses allocated to the General Partner for the current and all prior fiscal years. Second, such net profits shall be allocated to the Limited Partners pro rata in accordance with their respective sharing ratios. For any fiscal year in which the Partnership has net losses, such net losses shall be first allocated to the Limited Partners in proportion to their respective adjusted capital account balances, as defined by the Partnership Agreement, (before taking into account such net losses) until their adjusted capital account balances have been reduced to zero. Second, all remaining net losses shall be allocated to the General Partner. The General Partner may distribute to the Limited Partners funds of the Partnership that the General Partner reasonably determines are not needed for the payment of existing or foreseeable Partnership obligations and expenditures.

Common Units

The change in Energy Transfer Common Units during the years ended December 31, 2021, 2020 and 2019 was as follows:

	Years Ended December 31,		
	2021	2020	2019
Number of Common Units, beginning of period	2,702.4	2,689.6	2,619.4
Common Units issued in mergers and acquisitions [(1)]	374.6	—	57.6
Common Units repurchased	(4.2)	—	(1.9)
Issuance of Common Units [(2)]	9.7	12.8	14.5
Number of Common Units, end of period	3,082.5	2,702.4	2,689.6

(1) In December 2019, Energy Transfer issued 57.6 million Energy Transfer Common Units in connection with the SemGroup acquisition. In December 2021, Energy Transfer issued 374.6 million Energy Transfer Common Units in connection with the Enable Acquisition.

(2) Includes common units issued in connection with the distribution reinvestment program and restricted unit vestings.

Energy Transfer Class A Units

As of February 11, 2022, the Partnership had outstanding 763,021,449 Class A units ("Energy Transfer Class A Units") representing limited partner interests in the Partnership to the General Partner. The Energy Transfer Class A Units are entitled to vote together with the Partnership's common units, as a single class, except as required by law. Additionally, Energy Transfer's partnership agreement provides that, under certain circumstances, upon the issuance by the Partnership of additional common units or any securities that have voting rights that are pari passu with the Partnership common units, the Partnership will issue to any holder of Energy Transfer Class A Units additional Energy Transfer Class A Units such that the holder maintains a voting interest in the Partnership that is identical to its voting interest in the Partnership prior to such issuance. The Energy Transfer Class A Units are not entitled to distributions and otherwise have no economic attributes.

Energy Transfer Repurchase Program

In February 2015, the Partnership announced a common unit repurchase program, whereby the Partnership may repurchase up to an additional $2 billion of Energy Transfer Common Units in the open market at the Partnership's discretion, subject to market conditions and other factors, and in accordance with applicable regulatory requirements. The Partnership repurchased 4.2 million Energy Transfer Common Units under this program in 2021 and zero in 2020. As of December 31, 2021, $880 million remained available to repurchase under the current program.

Energy Transfer Distribution Reinvestment Program

During the year ended December 31, 2021, distributions of $33 million were reinvested under the distribution reinvestment program. As of December 31, 2021, a total of 17 million common units remain available to be issued under the existing registration statement in connection with the distribution reinvestment program.

Sale of Common Units by Subsidiaries

Energy Transfer on a stand-alone basis (the "Parent Company") accounts for the difference between the carrying amount of its investment in subsidiaries and the underlying book value arising from issuance of units by subsidiaries (excluding unit issuances to the Parent Company) as a capital transaction. If a subsidiary issues units at a price less than the Parent Company's carrying value per unit, the Parent Company assesses whether the investment has been impaired, in which case a provision would be reflected in our statement of operations. The Parent Company did not recognize any impairment related to the issuances of subsidiary common units during the periods presented.

Energy Transfer Preferred Units

Conversion of ETO Preferred Units to Energy Transfer Preferred Units

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

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

As of 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, 2020	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Preferred units conversion	943	547	440	434	786	504	1,114	—	4,768
Units issued for cash	—	—	—	—	—	—	—	889	889
Distributions to partners	(30)	(18)	(25)	(25)	(45)	(34)	(79)	(24)	(280)
Units issued in Enable Acquisition	—	—	—	—	—	—	392	—	392
Other, net	—	—	—	—	—	—	—	(3)	(3)
Net income	45	27	25	25	45	26	61	31	285
Balance, December 31, 2021	$ 958	$ 556	$ 440	$ 434	$ 786	$ 496	$ 1,488	$ 893	$ 6,051

Energy Transfer Series A Preferred Units

Distributions on the Energy Transfer Series A Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2023, at a rate of 6.250% per annum of the stated liquidation preference of $1,000. On and after February 15, 2023, distributions on the Energy Transfer Series A Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.028% per annum. The Energy Transfer Series A Preferred Units are redeemable at Energy Transfer’s option on or after February 15, 2023 at a redemption price of $1,000 per Energy Transfer Series A Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Energy Transfer Series B Preferred Units

Distributions on the Energy Transfer Series B Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, February 15, 2028, at a rate of 6.625% per annum of the stated liquidation preference of $1,000. On and after February 15, 2028, distributions on the Energy Transfer Series B Preferred Units will accumulate at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.155% per annum. The Energy Transfer Series B Preferred Units are redeemable at Energy Transfer’s option on or after February 15, 2028 at a redemption price of $1,000 per Energy Transfer Series B Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Energy Transfer Series C Preferred Units

Distributions on the Energy Transfer Series C Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2023, at a rate of 7.375% per annum of the stated liquidation preference of $25. On and after May 15, 2023, distributions on the Energy Transfer Series C Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.530% per annum. The Energy Transfer Series C Preferred Units are redeemable at Energy Transfer’s option on or after May 15, 2023 at a redemption price of $25 per Energy Transfer Series C Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Energy Transfer Series D Preferred Units

Distributions on the Energy Transfer Series D Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, August 15, 2023, at a rate of 7.625% per annum of the stated liquidation preference of $25. On and after August 15, 2023, distributions on the Energy Transfer Series D Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 4.738% per annum. The Energy Transfer Series D Preferred Units are redeemable at Energy Transfer’s option on or after August 15, 2023 at a redemption price of $25 per Energy Transfer Series D Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Energy Transfer Series E Preferred Units

Distributions on the Energy Transfer Series E Preferred Units will accrue and be cumulative from and including the date of original issue to, but excluding, May 15, 2024, at a rate of 7.600% per annum of the stated liquidation preference of $25. On and after May 15, 2024, distributions on the Energy Transfer Series E Preferred Units will accumulate at a percentage of the $25 liquidation preference equal to an annual floating rate of the three-month LIBOR, determined quarterly, plus a spread of 5.161% per annum. The Energy Transfer Series E Preferred Units are redeemable at Energy Transfer's option on or after May 15, 2024 at a redemption price of $25 per Energy Transfer Series E Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Energy Transfer Series F Preferred Units

Distributions on the Series F Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2025, at a rate equal to 6.750% per annum of the $1,000 liquidation preference. On and after May 15, 2025, the distribution rate on the Energy Transfer Series F Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.134% per annum. The Energy Transfer Series F Preferred Units are redeemable at Energy Transfer's option on or after May 15, 2025 at a redemption price of $1,000 per Energy Transfer Series F Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption.

Energy Transfer Series G Preferred Units

Distributions on the Energy Transfer Series G Preferred Units are cumulative from and including the original issue date and will be payable semi-annually in arrears on the 15th day of May and November of each year, commencing on May 15, 2020 to, but excluding, May 15, 2030, at a rate equal to 7.125% per annum of the $1,000 liquidation preference. On and after May 15, 2030, the distribution rate on the Energy Transfer Series G Preferred Units will equal a percentage of the $1,000 liquidation preference equal to the five-year U.S. treasury rate plus a spread of 5.306% per annum. The Energy Transfer Series G Preferred Units are redeemable at Energy Transfer's option on or after May 15, 2030 at a redemption price of $1,000 per Energy Transfer Series G Preferred Unit, plus an amount equal to all accumulated and unpaid distributions thereon to, but excluding, the date of redemption. On December 2, 2021, Energy Transfer issued 384,780 Energy Transfer Series G Preferred Units in connection with the Enable Acquisition, as discussed in Note 3.

Energy Transfer Series H Preferred Units

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

Subsidiary Equity Transactions

Sunoco LP's Equity Distribution Program

Sunoco LP is party to an equity distribution agreement for an at-the-market ("ATM") offering pursuant to which Sunoco LP may sell its common units from time to time. For the years ended December 31, 2021, 2020 and 2019, Sunoco LP issued no units under its ATM program. As of December 31, 2021, $295 million of Sunoco LP common units remained available to be issued under the currently effective equity distribution agreement.

USAC's Distribution Reinvestment Program

During the year ended December 31, 2021 and 2020, distributions of $1.8 million and $1.9 million, respectively, were reinvested under the USAC distribution reinvestment program resulting in the issuance of approximately 118,399 and 188,695 USAC common units, respectively.

USAC's Warrant Private Placement

On April 2, 2018, USAC issued 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. The USAC Warrants may be exercised by the holders thereof at any time beginning on the one year anniversary of the closing date and before the tenth anniversary of the closing date. Upon exercise of the USAC Warrants, USAC may, at its option, elect to settle the USAC Warrants in common units on a net basis.

USAC's Class B Units

The USAC Class B Units, all of which were previously owned by ETO, were a new class of partnership interests of USAC that had substantially all of the rights and obligations of a USAC common unit, except the USAC Class B Units did not participate in distributions for the first four quarters following the closing date of the USAC Transaction on April 2, 2018. Each USAC Class B Unit automatically was converted into one USAC common unit on the first business day following the record date attributable to the quarter ending June 30, 2019.

On July 30, 2019, the 6,397,965 USAC Class B units held by the Partnership converted into 6,397,965 common units representing limited partner interests in USAC. These common units participate in distributions declared by USAC.

Quarterly Distributions of Available Cash

Our distribution policy is consistent with the terms of our Partnership Agreement, which requires that we distribute all of our available cash quarterly.

Our distributions declared and paid with respect to our common units were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2018	February 8, 2019	February 19, 2019	$ 0.3050
March 31, 2019	May 7, 2019	May 20, 2019	0.3050
June 30, 2019	August 6, 2019	August 19, 2019	0.3050
September 30, 2019	November 5, 2019	November 19, 2019	0.3050
December 31, 2019	February 7, 2020	February 19, 2020	0.3050
March 31, 2020	May 7, 2020	May 19, 2020	0.3050
June 30, 2020	August 7, 2020	August 19, 2020	0.3050
September 30, 2020	November 6, 2020	November 19, 2020	0.1525
December 31, 2020	February 8, 2021	February 19, 2021	0.1525
March 31, 2021	May 11, 2021	May 19, 2021	0.1525
June 30, 2021	August 6, 2021	August 19, 2021	0.1525
September 30, 2021	November 5, 2021	November 19, 2021	0.1525
December 31, 2021	February 8, 2022	February 18, 2022	0.1750

Energy Transfer Preferred Unit Distributions

Distributions on Energy Transfer's Series A, Series B, Series C, Series D, Series E, Series F, Series G and Series H preferred units declared and/or paid by Energy Transfer were as follows:

Period Ended	Record Date	Payment Date	Series A (1)	Series B (1)	Series C	Series D	Series E	Series F (1)	Series G (1)	Series H (1)
March 31, 2021	May 3, 2021	May 17, 2021	$—	$—	$0.4609	$0.4766	$0.4750	$33.7500	$35.63	$—
June 30, 2021	August 2, 2021	August 16, 2021	31.25	33.13	0.4609	0.4766	0.4750	—	—	—
September 30, 2021	November 1, 2021	November 15, 2021	—	—	0.4609	0.4766	0.4750	33.7500	35.63	27.08 *
December 31, 2021	February 1, 2022	February 15, 2022	31.25	33.13	0.4609	0.4766	0.4750	—	—	—

* Represents prorated initial distribution.

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

Sunoco LP Cash Distributions

The following table illustrates the percentage allocations of available cash from operating surplus between Sunoco LP's common unitholders and the holder of its IDRs based on the specified target distribution levels, after the payment of distributions to Class C unitholders. The amounts set forth under "marginal percentage interest in distributions" are the percentage interests of the IDR holder and the common unitholders in any available cash from operating surplus which Sunoco LP distributes up to and including the corresponding amount in the column "total quarterly distribution per unit target amount." The percentage interests shown for common unitholders and IDR holder for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Common Unitholders	Holder of IDRs
Minimum Quarterly Distribution	$0.4375	100%	—%
First Target Distribution	$0.4375 to $0.503125	100%	—%
Second Target Distribution	$0.503125 to $0.546875	85%	15%
Third Target Distribution	$0.546875 to $0.656250	75%	25%
Thereafter	Above $0.656250	50%	50%

Distributions on Sunoco LP's units declared and/or paid by Sunoco LP were as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2018	February 6, 2019	February 14, 2019	$ 0.8255
March 31, 2019	May 7, 2019	May 15, 2019	0.8255
June 30, 2019	August 6, 2019	August 14, 2019	0.8255
September 30, 2019	November 5, 2019	November 19, 2019	0.8255
December 31, 2019	February 7, 2020	February 19, 2020	0.8255
March 31, 2020	May 7, 2020	May 19, 2020	0.8255
June 30, 2020	August 7, 2020	August 19, 2020	0.8255
September 30, 2020	November 6, 2020	November 19, 2020	0.8255
December 31, 2020	February 8, 2021	February 19, 2021	0.8255
March 31, 2021	May 11, 2021	May 19, 2021	0.8255
June 30, 2021	August 6, 2021	August 19, 2021	0.8255
September 30, 2021	November 5, 2021	November 19, 2021	0.8255
December 31, 2021	February 8, 2022	February 18, 2022	0.8255

USAC Cash Distributions

Energy Transfer owns approximately 46.1 million USAC common units. As of December 31, 2021, USAC had approximately 97.3 million common units outstanding. USAC currently has a non-economic general partner interest and no outstanding IDRs.

Distributions on USAC's units declared and/or paid by USAC subsequent to the USAC transaction on April 2, 2018 were as follows:

Quarter Ended	Record Date	Payment Date	Rate	
December 31, 2018	January 28, 2019	February 8, 2019	$	0.5250
March 31, 2019	April 29, 2019	May 10, 2019		0.5250
June 30, 2019	July 29, 2019	August 9, 2019		0.5250
September 30, 2019	October 28, 2019	November 8, 2019		0.5250
December 31, 2019	January 27, 2020	February 7, 2020		0.5250
March 31, 2020	April 27, 2020	May 8, 2020		0.5250
June 30, 2020	July 31, 2020	August 10, 2020		0.5250
September 30, 2020	October 26, 2020	November 6, 2020		0.5250
December 31, 2020	January 25, 2021	February 5, 2021		0.5250
March 31, 2021	April 26, 2021	May 7, 2021		0.5250
June 30, 2021	July 26, 2021	August 6, 2021		0.5250
September 30, 2021	October 25, 2021	November 5, 2021		0.5250
December 31, 2021	January 24, 2022	February 4, 2022		0.5250

Accumulated Other Comprehensive Income

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

	December 31,			
	2021		2020	
Available-for-sale securities	$	19	$	18
Foreign currency translation adjustment		13		7
Actuarial gain (loss) related to pensions and other postretirement benefits		5		(7)
Investments in unconsolidated affiliates, net		(11)		(14)
Total AOCI, net of tax		26		4
Amounts attributable to noncontrolling interests		(3)		2
Total AOCI included in partners' capital, net of tax	$	23	$	6

The table below sets forth the tax amounts included in the respective components of other comprehensive income:

	December 31,			
	2021		2020	
Available-for-sale securities	$	(1)	$	(1)
Foreign currency translation adjustment		6		8
Actuarial loss relating to pension and other postretirement benefits		1		3
Total	$	6	$	10

9. EQUITY INCENTIVE PLANS:

We, Sunoco LP and USAC, have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase Common Units, restricted units, phantom units, distribution equivalent rights ("DERs"), common unit appreciation rights, cash restricted units and other equity-based compensation awards. As of December 31, 2021, an aggregate total of 12.7 million Energy Transfer Common Units remain available to be awarded under our equity incentive plans.

Energy Transfer Long-Term Incentive Plan

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year service vesting requirement, with vesting based on continued employment as of each applicable vesting date. Upon vesting, Energy Transfer Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. We refer to these rights as "distribution equivalent rights." Under our equity incentive plans, our non-employee directors each receive grants with a five-year service vesting requirement.

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2020	29.4	$ 11.26
Replacement awards issued in the Enable Acquisition	2.7	8.32
Awards granted	11.9	8.46
Awards vested	(6.4)	15.10
Awards forfeited	(1.5)	11.23
Unvested awards as of December 31, 2021	36.1	$ 9.49

During the years ended December 31, 2021, 2020, and 2019, the weighted average grant-date fair value per unit award granted was $8.46, $6.29 and $12.51, respectively, and the total fair value of awards vested was $52 million, $51 million, and $47 million, respectively, based on the market price of the respective Common Units as of the vesting date. As of December 31, 2021, a total of 36.1 million unit awards remain unvested, for which Energy Transfer expects to recognize a total of $208 million in compensation expense over a weighted average period of 2.9 years.

Cash Restricted Units. The Partnership has also granted cash restricted units, which vest through three years of service. A cash restricted unit entitles the award recipient to receive cash equal to the market value of one Energy Transfer Common Unit upon vesting. For the years ended December 31, 2021 and 2020, the Partnership granted a total of 3.9 million and 7.7 million cash restricted units, respectively. As of December 31, 2021, a total of 8.6 million cash restricted units were unvested. As of December 31, 2021, the Partnership's consolidated balance sheet reflected aggregate liabilities of $3.1 million related to cash restricted units.

Subsidiary Long-Term Incentive Plans

Each of Sunoco LP and USAC has granted restricted or phantom unit awards (collectively, the "Subsidiary Unit Awards") to employees and directors that entitle the grantees to receive common units of the respective subsidiary. In some cases, at the discretion of the respective subsidiary's compensation committee, the grantee may instead receive an amount of cash equivalent to the value of common units upon vesting. Substantially all of the Subsidiary Unit Awards are time-vested grants, which generally vest over a three or five-year period, that entitles the grantees of the unit awards to receive an amount of cash equal to the per unit cash distributions made by the respective subsidiaries during the period the restricted unit is outstanding.

The following table summarizes the activity of the Subsidiary Unit Awards:

	Sunoco LP		USAC	
	Number of Units	Weighted Average Grant-Date Fair Value Per Unit	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2020	2.1	$ 28.63	2.1	$ 14.88
Awards granted	0.5	37.72	0.6	14.92
Awards vested	(0.5)	27.06	(0.4)	15.13
Awards forfeited	(0.1)	28.57	(0.1)	14.50
Unvested awards as of December 31, 2021	2.0	$ 30.92	2.2	$ 13.57

The following table summarizes the weighted average grant-date fair value per unit award granted:

	Years Ended December 31,		
	2021	2020	2019
Sunoco LP	$ 37.72	$ 28.63	$ 30.70
USAC	14.92	12.55	15.88

The total fair value of Subsidiary Unit Awards vested for the years ended December 31, 2021, 2020 and 2019 was $24 million, $16 million, and $17 million, respectively, based on the market price of Sunoco LP and USAC common units as of the vesting date. As of December 31, 2021, estimated compensation cost related to Subsidiary Unit Awards not yet recognized was $56 million, and the weighted average period over which this cost is expected to be recognized in expense is 3.4 years.

10. INCOME TAXES:

As a partnership, we are not subject to United States federal income tax and most state income taxes. However, the Partnership conducts certain activities through corporate subsidiaries which are subject to federal and state income taxes. The components of the federal and state income tax expense (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended December 31,		
	2021	2020	2019
Current expense (benefit):			
Federal	$ 19	$ (6)	$ (20)
State	24	32	(2)
Foreign	—	1	—
Total	43	27	(22)
Deferred expense (benefit):			
Federal	246	176	174
State	(106)	41	43
Foreign	1	(7)	—
Total	141	210	217
Total income tax expense	$ 184	$ 237	$ 195

Historically, our effective tax rate has differed from the statutory rate primarily due to partnership earnings that are not subject to United States federal and most state income taxes at the partnership level. A reconciliation of income tax expense at the United States statutory rate to the Partnership's income tax benefit for the years ended December 31, 2021, 2020 and 2019 is as follows:

	Years Ended December 31,		
	2021	2020	2019
Income tax expense at United States statutory rate	$ 1,443	$ 79	$ 1,054
Increase (reduction) in income taxes resulting from:			
Partnership earnings not subject to tax	(1,211)	88	(866)
Noncontrolling interests	—	16	—
State tax, net of federal tax benefit	85	58	12
Statutory rate change	(46)	—	—
Valuation allowance	(63)	—	—
Uncertain tax positions	(34)	—	—
Dividend received deduction	(4)	—	(3)
Foreign taxes	1	(7)	—
Other	13	3	(2)
Income tax expense	$ 184	$ 237	$ 195

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows:

	December 31, 2021	December 31, 2020
Deferred income tax assets:		
Net operating losses and other carryforwards	$ 803	$ 1,047
Pension and other postretirement benefits	—	—
Other	35	34
Total deferred income tax assets	838	1,081
Valuation allowance	(34)	(134)
Net deferred income tax assets	804	947
Deferred income tax liabilities:		
Property, plant and equipment	(314)	(298)
Investments in affiliates	(4,042)	(3,994)
Trademarks	(79)	(77)
Other	(17)	(6)
Total deferred income tax liabilities	(4,452)	(4,375)
Net deferred income taxes	$ (3,648)	$ (3,428)

As of December 31, 2021, ETP Holdco had a federal net operating loss carryforward of $3.1 billion, of which $1.1 billion will expire in 2031 through 2037 while the remaining can be carried forward indefinitely. A total of $338 million of the federal net operating loss carryforward is limited under IRC §382. Although we expect to fully utilize the IRC §382 limited federal net operating loss, the amount utilized in a particular year may be limited. As of December 31, 2021, Sunoco Retail LLC (formerly Sunoco Property Company LLC), a corporate subsidiary of Sunoco LP, had a state net operating loss carryforward of $114 million, which we expect to fully utilize. Sunoco Retail LLC has no federal net operating loss carryforward.

Our corporate subsidiaries have state net operating loss carryforward benefits of $116 million, net of federal tax, some of which expire between 2022 and 2040, while others are carried forward indefinitely. Our corporate subsidiaries have Canadian net operating losses of $6 million that will begin to expire in 2033. Our corporate subsidiaries have cumulative excess business interest expense of $79 million available for carryforward indefinitely. A valuation allowance of $9 million is attributable to state net operating loss carryforward benefits primarily attributable to significant restrictions on their use in the Commonwealth of Pennsylvania. A separate valuation allowance of $25 million is attributable to foreign tax credits.

The following table sets forth the changes in unrecognized tax benefits:

	Years Ended December 31, 2021	2020	2019
Balance at beginning of year	$ 90	$ 94	$ 624
Additions attributable to tax positions taken in prior years	—	—	11
Reduction attributable to tax positions taken in prior years	(34)	—	(541)
Lapse of statute	—	(4)	—
Balance at end of year	$ 56	$ 90	$ 94

As of December 31, 2021, we had $56 million ($51 million after federal income tax benefits) related to tax positions which, if recognized, would impact our effective tax rate.

Our policy is to accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense. During 2021, we recognized interest and penalties of less than $7 million. At December 31, 2021, we have interest and penalties accrued of $17 million, net of tax.

We appealed the adverse Court of Federal Claims decision against ETC Sunoco regarding the IRS' denial of ethanol blending credits claims under Section 6426 to the Federal Circuit. The Federal Circuit affirmed the CFC's denial on November 1, 2018. ETC Sunoco filed a petition for certiorari with the Supreme Court on May 24, 2019 to review the Federal Circuit's affirmation of the CFC's ruling, and the Court denied Sunoco's petition on October 7, 2019. Due to the uncertainty surrounding the litigation, a reserve of $530 million was previously established for the full amount of the pending refund claims, and the receivable and reserve for this issue were netted in the consolidated balance sheet. Subsequent to the Supreme Court's denial of the petition in October 2019, the receivable and reserve have been reversed, with no impact to the Partnership's financial position and results of operations.

In November 2015, the Pennsylvania Commonwealth Court determined in Nextel Communications v. Commonwealth ("Nextel") that the Pennsylvania limitation on NOL carryforward deductions violated the uniformity clause of the Pennsylvania Constitution and struck the NOL limitation in its entirety. In October 2017, the Pennsylvania Supreme Court affirmed the decision with respect to the uniformity clause violation; however, the Court reversed with respect to the remedy and instead severed the flat-dollar limitation, leaving the percentage-based limitation intact. Nextel subsequently filed a petition for writ of certiorari with the United States Supreme Court, and this was denied on June 11, 2018. Certain Pennsylvania taxpayers have subsequently undertaken litigation in Pennsylvania state courts on issues not addressed by the Pennsylvania Supreme Court in Nextel, specifically, whether the Due Process and Equal Protection Clauses of the United States Constitution and the Remedies Clause of the Pennsylvania Constitution require a court to grant the taxpayer relief. On December 22, 2021, the Pennsylvania Supreme Court found in General Motors Corporation v. Commonwealth ("GM") that the taxpayer was entitled to meaningful backwards looking relief under the Due Process Clause, meaning the Commonwealth must equalize the taxpayer's position with taxpayers who were not affected by the NOL cap in place for the year at issue. The Court therefore held the taxpayer was entitled to a refund by calculating its tax for that year with an uncapped NOL deduction. We believe the Pennsylvania Supreme Court's ruling in GM will more likely than not be upheld if challenged by the Commonwealth. ETC Sunoco previously recognized approximately $67 million ($53 million after federal income tax benefits) in tax benefit based on previously filed tax returns and certain previously filed protective claims as relates to its cases currently held pending the Nextel matter. In addition, based upon the Pennsylvania Supreme Court's October 2017 decision, and because of uncertainty in the breadth of the application of the decision, ETC Sunoco previously reserved $34 million ($27 million after federal income tax benefits) against the receivable. Subsequent to the Pennsylvania Supreme Court's decision in GM, the reserve has been reversed and the entire tax benefit of $34 million ($27 million after federal income tax benefit) has been recognized by the Partnership.

In general, Energy Transfer and its subsidiaries are no longer subject to examination by the IRS, and most state jurisdictions, for the 2016 and prior tax years.

USAC is currently under examination by the IRS for years 2019 and 2020. Energy Transfer and its other subsidiaries also have various state and local income tax returns in the process of examination or administrative appeal in various jurisdictions. We believe the appropriate accruals or unrecognized tax benefits have been recorded for any potential assessment with respect to these examinations.

11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Winter Storm Impacts

Winter Storm Uri, which occurred in February 2021, resulted in one-time impacts to the Partnership's consolidated net income and also affected the results of operations in certain segments. The recognition of the impacts of Winter Storm Uri during the year ended December 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.

FERC Proceedings

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. On January 25, 2022, the chief judge assigned an administrative law judge and set a timeline for a prehearing conference. 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. Energy Transfer and Rover intend to vigorously defend this claim.

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. Enforcement Staff has provided Rover with a notice pursuant to Section 1b.19 of the Commission's regulations that Enforcement Staff intends to recommend that the Commission pursue an enforcement action against Rover and the Partnership. The company disagrees with Enforcement Staff's findings and intends to vigorously defend against any potential penalty. On December 16, 2021, FERC issued an Order to Show Cause and Notice of Proposed Penalty (Docket No. IN17-4-000), ordering Rover to show cause why it 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 filed an answer responding to this Order on December 22, 2021. 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, and the non-public nature of the investigation, 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.

By the 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.

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, including Page 700, 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 enters into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. Energy Transfer believes that the terms of these agreements are commercially reasonable and will not have a material adverse effect on its financial position or results of operations.

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

We have certain non-cancelable 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 statements of operations:

	Years Ended December 31,		
	2021	2020	2019
ROW expense	$ 48	$ 47	$ 45

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and crude oil are flammable and combustible. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

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

As of December 31, 2021 and 2020, accruals of approximately $144 million and $101 million, respectively, were reflected on our consolidated balance sheets related to contingent obligations that met both the probable and reasonably estimable criteria. In addition, we may recognize additional contingent losses in the future related to (i) contingent matters for which a loss is currently considered reasonably possible but not probable and/or (ii) losses in excess of amounts that have already been accrued for such contingent matters. In some of these cases, we are not able to estimate possible losses or a range of possible losses in excess of amounts accrued. For such matters where additional contingent losses can be reasonably estimated, the range of additional losses is estimated to be up to approximately $550 million.

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

Dakota Access Pipeline

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

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

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. The USACE also advised the District Court that it expected that the EIS will be completed by March 2022. On May 21, 2021, the District Court denied the Plaintiffs' request for an injunction. 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. The USACE now estimates that the EIS will be complete by the end of 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 LLC's ("Lone Star"), now known as Energy Transfer GC NGLs LLC, facilities in Mont Belvieu, Texas experienced an over-pressurization resulting in a subsurface release. The subsurface release caused a fire at Lone Star's South Terminal and damage to Lone Star's storage well operations at its South and North Terminals. Normal operations resumed at the facilities in the fall of 2016, with the exception of one of Lone Star's storage wells at the North Terminal that has not been returned to service. Lone Star has obtained payment for most of the losses it has submitted to the adjacent operator. Lone Star continues to quantify and seek reimbursement for outstanding losses.

MTBE Litigation

ETC Sunoco 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 December 31, 2021, Sunoco Defendants are defendants in five cases, including one case each initiated by the States of Maryland and Rhode Island, one by the Commonwealth of Pennsylvania and two by the Commonwealth of Puerto Rico. The more recent Puerto Rico action is a companion case alleging damages for additional sites beyond those at issue in the initial Puerto Rico action. The actions brought by the State of Maryland and Commonwealth of Pennsylvania have also named as defendants ETO, ETP Holdco, and Sunoco Partners Marketing & Terminals L.P. ("SPMT").

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

Regency Merger Litigation

On June 10, 2015, Adrian Dieckman ("Plaintiff"), a purported Regency unitholder, filed a class action complaint related to the Regency-ETO merger (the "Regency Merger") in the Court of Chancery of the State of Delaware (the "Regency Merger Litigation"), on behalf of Regency's common unitholders against Regency GP LP, Regency GP LLC, Energy Transfer, ETO, Energy Transfer Partners GP, L.P., and the members of Regency's board of directors.

The Regency Merger Litigation alleges that the Regency Merger breached the Regency partnership agreement. On March 29, 2016, the Delaware Court of Chancery granted the defendants' motion to dismiss the lawsuit in its entirety. Plaintiff appealed, and the Delaware Supreme Court reversed the judgment of the Court of Chancery. Plaintiff then filed an Amended Verified Class Action Complaint, which defendants moved to dismiss. The Court of Chancery granted in part and denied in part the motions to dismiss, dismissing the claims against all defendants other than Regency GP LP and

Regency GP LLC (the "Regency Defendants"). The Court of Chancery later granted Plaintiff's unopposed motion for class certification. Trial was held on December 10-16, 2019, and a post-trial hearing was held on May 6, 2020. On February 15, 2021, the Court of Chancery ruled in favor of the Regency Defendants on all claims at issue in this litigation, determined that the Regency Merger was fair and reasonable to Regency, and denied Plaintiff any relief.

On November 3, 2021, the Delaware Supreme Court affirmed the Court of Chancery's judgment in favor of Regency Defendants, bringing this matter to a conclusion.

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 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. The Court did not reach a decision on Williams' tax-related claims. 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.

Energy Transfer Defendants cannot predict the ultimate outcome of the Williams Litigation nor can the Energy Transfer Defendants predict the amount of time and expense that will be required to resolve the Williams Litigation.

Rover

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

Revolution

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

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

Chester County, Pennsylvania Investigation

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

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

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

On April 22, 2021, the Chester County DA filed a Complaint and Consent Decree in the Court of Common Pleas of Chester County, Pennsylvania constituting a settlement agreement between the Chester County DA and the Partnership. A status conference was held on May 10, 2021, and an Amended Consent Decree was filed on June 16, 2021, which was approved and entered by the Court on December 20, 2021.

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 Pennsylvania Pipeline Construction

Four 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. 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.); and *King v. LE GP*, Case No. 3:20-cv-00719-X (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. 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 Lawsuit

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

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

On August 27, 2020, SPMT filed its Notice of Appeal with the 10th Circuit and appealed the entirety of the Order. The matter 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, SPMT 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 SPMT to obtain adequate relief. SPMT cannot predict the outcome of the case, nor can SPMT predict the amount of time and expense that will be required to resolve the appeal but intends to vigorously appeal the entirety of the Order, including re-urging the district court to modify the Order and appealing the dismissal of SPMT's appeal to the United States Supreme Court.

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 the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

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

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 PCBs. PCB assessments are ongoing and, in some cases, our subsidiaries could be contractually responsible for contamination caused by other parties.
- certain gathering and processing systems are responsible for soil and groundwater remediation related to releases of hydrocarbons.

- legacy sites related to Sunoco, Inc. that are subject to environmental assessments, including formerly owned terminals and other logistics assets, retail sites that the Partnership no longer operates, closed and/or sold refineries and other formerly owned sites.
- the Partnership is potentially subject to joint and several liability for the costs of remediation at sites at which it has been identified as a potentially responsible party ("PRP"). As of December 31, 2021, 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 would require disclosure in our consolidated financial statements.

	December 31,	
	2021	2020
Current	$ 46	$ 44
Non-current	247	262
Total environmental liabilities	$ 293	$ 306

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

During the years ended December 31, 2021 and 2020, the Partnership recorded $28 million and $29 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.

12. REVENUE:

Disaggregation of revenue

The major types of revenue within our reportable segments, 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;
  - fuel distribution and marketing;
  - all other;
- investment in USAC;
  - contract operations;
  - retail parts and services; and
- all other.

Note 16 depicts the disaggregation of revenue by segment, with revenue amounts reflected in accordance with ASC Topic 606.

Intrastate transportation and storage revenue

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

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

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

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from our marketing operations, and from producers at the wellhead.

Interstate transportation and storage revenue

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

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

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

Lake Charles LNG's revenues are primarily derived from terminalling services for shippers by receiving LNG at the facility for storage and delivering such LNG to shippers, either in liquid state or gaseous state after regasification. Lake Charles LNG derives all of its revenue from a series of long-term contracts with a wholly-owned subsidiary of Royal Dutch Shell plc ("Shell"). Terminalling revenue is generated from fees paid by Shell for storage and other associated services at the terminal. Payment for services under these contracts are typically due the month after the services have been performed.

The terminalling agreements are considered to be firm agreements, because they include fixed fee components that are charged regardless of the volumes transported by Shell or services provided at the terminal.

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

Midstream revenue

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

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

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

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

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

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

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

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

Our midstream segment also generates revenues from the sale of residue gas and NGLs at the tailgate of our processing facilities primarily to affiliates and some third-party customers.

NGL and refined products transportation and services revenue

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

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

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

Crude oil transportation and services revenue

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

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

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

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

Sunoco LP’s fuel distribution and marketing revenue

Sunoco LP’s fuel distribution and marketing operations earn revenue from the following channels: sales to dealers, sales to distributors, unbranded wholesale revenue, commission agent revenue, rental income and other income. Motor fuel revenue consists primarily of the sale of motor fuel under supply agreements with third party customers and affiliates. Fuel supply contracts with Sunoco LP’s customers generally provide that Sunoco LP distribute motor fuel at a formula price based on published rates, volume-based profit margin, and other terms specific to the agreement. The customer is invoiced the agreed-upon price with most payment terms ranging less than 30 days. If the consideration promised in a contract includes a variable amount, Sunoco LP estimates the variable consideration amount and factors in such an estimate to determine the transaction price under the expected value method.

Revenue is recognized under the motor fuel contracts at the point in time the customer takes control of the fuel. At the time control is transferred to the customer the sale is considered final, because the agreements do not grant customers the right to return motor fuel. Under the new standard, to determine when control transfers to the customer, the shipping terms of the contract are assessed as shipping terms are considered a primary indicator of the transfer of control. For FOB shipping point terms, revenue is recognized at the time of shipment. The performance obligation with respect to the sale of goods is satisfied at the time of shipment since the customer gains control at this time under the terms. Shipping and/or handling costs that occur before the customer obtains control of the goods are deemed to be fulfillment activities and are accounted for as fulfillment costs. Once the goods are shipped, Sunoco LP is precluded from redirecting the shipment to another customer and revenue is recognized.

Commission agent revenue consists of sales from commission agent agreements between Sunoco LP and select operators. Sunoco LP supplies motor fuel to sites operated by commission agents and sells the fuel directly to the end customer. In commission agent arrangements, control of the product is transferred at the point in time when the goods are sold to the end customer. To reflect the transfer of control, Sunoco LP recognizes commission agent revenue at the point in time fuel is sold to the end customer.

Sunoco LP receives rental income from leased or subleased properties. Revenue from leasing arrangements for which Sunoco LP is the lessor are recognized ratably over the term of the underlying lease.

Sunoco LP’s all other revenue

Sunoco LP’s all other operations earn revenue from the following channels: motor fuel sales, rental income and other income. Motor fuel sales consist of fuel sales to consumers at company-operated retail stores. Other income includes merchandise revenue that comprises the in-store merchandise and food service sales at company-operated retail stores, and other revenue that represents a variety of other services within Sunoco LP’s all other operations including credit card processing, car washes, lottery, automated teller machines, money orders, prepaid phone cards and wireless services. Revenue from all other operations is recognized when (or as) the performance obligations are satisfied (i.e. when the customer obtains control of the good or the service is provided).

USAC's contract operations revenue

USAC's revenue from contracted compression, station, gas treating and maintenance services is recognized ratably under its fixed-fee contracts over the term of the contract as services are provided to its customers. Initial contract terms typically range from six months to five years, however USAC usually continues to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. USAC primarily enters into fixed-fee contracts whereby its customers are required to pay the monthly fee even during periods of limited or disrupted throughput. Services are generally billed monthly, one month in advance of the commencement of the service month, except for certain customers who are billed at the beginning of the service month, and payment is generally due 30 days after receipt of the invoice. Amounts invoiced in advance are recorded as deferred revenue until earned, at which time they are recognized as revenue. The amount of consideration USAC receives and revenue it recognizes is based upon the fixed fee rate stated in each service contract.

Variable consideration exists in select contracts when billing rates vary based on actual equipment availability or volume of total installed horsepower.

USAC's contracts with customers may include multiple performance obligations. For such arrangements, USAC allocates revenues to each performance obligation based on its relative standalone service fee. USAC generally determines standalone service fees based on the service fees charged to customers or using expected cost plus margin.

The majority of USAC's service performance obligations are satisfied over time as services are rendered at selected customer locations on a monthly basis and based upon specific performance criteria identified in the applicable contract. The monthly service for each location is substantially the same service month to month and is promised consecutively over the service contract term. USAC measures progress and performance of the service consistently using a straight-line, time-based method as each month passes, because its performance obligations are satisfied evenly over the contract term as the customer simultaneously receives and consumes the benefits provided by its service. If variable consideration exists, it is allocated to the distinct monthly service within the series to which such variable consideration relates. USAC has elected to apply the invoicing practical expedient to recognize revenue for such variable consideration, as the invoice corresponds directly to the value transferred to the customer based on its performance completed to date.

There are typically no material obligations for returns or refunds. USAC's standard contracts do not usually include material non-cash consideration.

USAC's retail parts and services revenue

USAC's retail parts and service revenue is earned primarily on freight and crane charges that are directly reimbursable by USAC's customers and maintenance work on units at its customers' locations that are outside the scope of its core maintenance activities. Revenue from retail parts and services is recognized at the point in time the part is transferred or service is provided and control is transferred to the customer. At such time, the customer has the ability to direct the use of the benefits of such part or service after USAC has performed its services. USAC bills upon completion of the service or transfer of the parts, and payment is generally due 30 days after receipt of the invoice. The amount of consideration USAC receives and revenue it recognizes is based upon the invoice amount. There are typically no material obligations for returns, refunds, or warranties. USAC's standard contracts do not usually include material variable or non-cash consideration.

All other revenue

Our all other segment primarily includes our compression equipment business which provides full-service compression design and manufacturing services for the oil and gas industry. It also includes the management of coal and natural resources properties and the related collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. These operations also include end-user coal handling facilities.

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 allows customers to apply such fees against services to be provided at a future point in time. These amounts are reflected as deferred revenue until the customer applies the deficiency fees to services provided or becomes unable to use the fees as payment for future services due to expiration of the contractual period the fees can be applied or physical inability of the customer to utilize the fees due to capacity constraints. 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, 2019	$ 367
Additions	788
Revenue recognized	(846)
Balance, December 31, 2020	309
Additions	849
Revenue recognized	(699)
Balance, December 31, 2021	$ 459

The balances of Sunoco LP's contract assets and contract liabilities as of December 31, 2021 and 2020 were as follows:

	December 31,	
	2021	2020
Contract Balances		
Contract asset	$ 157	$ 121
Accounts receivable from contracts with customers	463	256

Costs to Obtain or Fulfill a Contract

Sunoco LP recognizes an asset from the costs incurred to obtain a contract (e.g. sales commissions) only if it expects to recover those costs. On the other hand, the costs to fulfill a contract are capitalized if the costs are specifically identifiable to a contract, would result in enhancing resources that will be used in satisfying performance obligations in future and are expected to be recovered. These capitalized costs are recorded as a part of other current assets and other non-current assets and are amortized on a systematic basis consistent with the pattern of transfer of the goods or services to which such costs relate. The amount of amortization expense that Sunoco LP recognized for the years ended December 31, 2021, 2020 and 2019 was $21 million, $18 million and $17 million, respectively. Sunoco LP has also made a policy election of expensing the costs to obtain a contract, as and when they are incurred, in cases where the expected amortization period is one year or less.

Performance Obligations

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

Sunoco LP distributes fuel under long-term contracts to branded distributors, branded and unbranded third-party dealers, and branded and unbranded retail fuel outlets. Sunoco LP branded supply contracts with distributors generally have both time and volume commitments that establish contract duration. These contracts have an initial term of approximately nine years, with an estimated, volume-weighted term remaining of approximately four years.

As part of the asset purchase agreement with 7-Eleven, Sunoco LP and 7-Eleven and SEI Fuel (collectively, the "Distributor") have entered into a 15-year take-or-pay fuel supply agreement in which the Distributor is required to purchase a volume of fuel that provides Sunoco LP a minimum amount of gross profit annually. Sunoco LP expects to recognize this revenue in accordance with the contract as Sunoco LP transfers control of the product to the customer. However, in case of annual shortfall Sunoco LP will recognize the amount payable by the Distributor at the sooner of the time at which the Distributor makes up the shortfall or becomes contractually or operationally unable to do so. The transaction price of the contract is variable in nature, fluctuating based on market conditions. The Partnership has elected to take the practical expedient not to estimate the amount of variable consideration allocated to wholly unsatisfied performance obligations.

In some contractual arrangements, Sunoco LP grants dealers a franchise license to operate Sunoco LP's retail stores over the life of a franchise agreement. In return for the grant of the retail store license, the dealer makes a one-time nonrefundable franchise fee payment to Sunoco LP plus sales based royalties payable to Sunoco LP at a contractual rate during the period of the franchise agreement. Under the requirements of ASC Topic 606, the franchise license is deemed to be a symbolic license for which recognition of revenue over time is the most appropriate measure of progress toward complete satisfaction of the performance obligation. Revenue from this symbolic license is recognized evenly over the life of the franchise agreement.

As of December 31, 2021, the aggregate amount of transaction price allocated to unsatisfied (or partially satisfied) performance obligations was $38.76 billion, and the Partnership expects to recognize this amount as revenue within the time bands illustrated below:

	Years Ending December 31,				
	2022	2023	2024	Thereafter	Total
Revenue expected to be recognized on contracts with customers existing as of December 31, 2021	$ 6,189	$ 5,594	$ 4,775	$ 22,198	$ 38,756

Practical Expedients Utilized by the Partnership

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

- *Right to invoice:* The Partnership elected to utilize an output method to recognize revenue that is based on the amount to which the Partnership has a right to invoice a customer for services performed to date, if that amount corresponds directly with the value provided to the customer for the related performance or its obligation completed to date. As such, the Partnership recognized revenue in the amount to which it had the right to invoice customers.
- *Significant financing component:* The Partnership elected not to adjust the promised amount of consideration for the effects of significant financing component if the Partnership expects, at contract inception, that the period between the transfer of a promised good or service to a customer and when the customer pays for that good or service will be one year or less.
- *Unearned variable consideration:* The Partnership elected to only disclose the unearned fixed consideration associated with unsatisfied performance obligations related to our various customer contracts which contain both fixed and variable components.
- *Incremental costs of obtaining a contract:* The Partnership generally expenses sales commissions when incurred because the amortization period would have been less than one year. We record these costs within general and administrative expenses. The Partnership elected to expense the incremental costs of obtaining a contract when the amortization period for such contracts would have been one year or less.
- *Shipping and handling costs:* The Partnership elected to account for shipping and handling activities that occur after the customer has obtained control of a good as fulfillment activities (i.e., an expense) rather than as a promised service.
- *Measurement of transaction price:* The Partnership has elected to exclude from the measurement of transaction price all taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Partnership from a customer (i.e., sales tax, value added tax, etc.).
- *Variable consideration of wholly unsatisfied performance obligations:* The Partnership has elected to exclude the estimate of variable consideration to the allocation of wholly unsatisfied performance obligations.

13. LEASE ACCOUNTING:

Lessee Accounting

The Partnership leases terminal facilities, tank cars, office space, land and equipment under non-cancelable operating leases whose initial terms are typically five to 15 years, with some real estate leases having terms of 40 years or more, along with options that permit renewals for additional periods. At the inception of each, we determine if the arrangement is a lease or contains an embedded lease and review the facts and circumstances of the arrangement to classify lease assets as operating or finance leases under Topic 842. The Partnership has elected not to record any leases with terms of 12 months or less on the balance sheet.

At present, the majority of the Partnership's active leases are classified as operating in accordance with Topic 842. Balances related to operating leases are included in operating lease ROU assets, accrued and other current liabilities, operating lease current liabilities and non-current operating lease liabilities in our consolidated balance sheets. Finance leases represent a small portion of the active lease agreements and are included in finance lease ROU assets, current maturities of long-term debt and long-term debt, less current maturities in our consolidated balance sheets. The ROU assets represent the Partnership's right to use an underlying asset for the lease term and lease liabilities represent the obligation of the Partnership to make minimum lease payments arising from the lease for the duration of the lease term.

Most leases include one or more options to renew, with renewal terms that can extend the lease term from one to 20 years or greater. The exercise of lease renewal options is typically at the sole discretion of the Partnership and lease extensions are evaluated on a lease-by-lease basis. Leases containing early termination clauses typically require the agreement of both parties to the lease. At the inception of a lease, all renewal options reasonably certain to be exercised are considered when determining the lease term. Presently, the Partnership does not have leases that include options to purchase or automatic transfer of ownership of the leased property to the Partnership. The depreciable life of lease assets and leasehold improvements are limited by the expected lease term.

To determine the present value of future minimum lease payments, we use the implicit rate when readily determinable. Presently, because many of our leases do not provide an implicit rate, the Partnership applies its incremental borrowing rate based on the information available at the lease commencement date to determine the present value of minimum lease payments. The operating and finance lease ROU assets include any lease payments made and exclude lease incentives.

Minimum rent payments are expensed on a straight-line basis over the term of the lease. In addition, some leases require additional contingent or variable lease payments, which are based on the factors specific to the individual agreement. Variable lease payments the Partnership is typically responsible for include payment of real estate taxes, maintenance expenses and insurance.

For short-term leases (leases that have term of twelve months or less upon commencement), lease payments are recognized on a straight-line basis and no ROU assets are recorded.

The components of operating and finance lease amounts recognized in the accompanying consolidated balance sheet as of December 31, 2021 and 2020 were as follows:

	December 31,	
	2021	2020
Operating leases:		
Lease right-of-use assets, net	$ 826	$ 863
Operating lease current liabilities	47	53
Accrued and other current liabilities	1	1
Non-current operating lease liabilities	814	837
Finance leases:		
Property, plant and equipment, net	$ 1	$ 1
Lease right-of-use assets, net	12	3
Accrued and other current liabilities	1	1
Current maturities of long-term debt	3	1
Long-term debt, less current maturities	9	6
Other non-current liabilities	1	1

The components of lease expense for the years ended December 31, 2021 and 2020 were as follows:

	Income Statement Location	Year Ended December 31, 2021	Year Ended December 31, 2020
Operating lease costs:			
Operating lease cost	Cost of goods sold	$ 10	$ 14
Operating lease cost	Operating expenses	78	75
Operating lease cost	Selling, general and administrative	17	17
Total operating lease costs		105	106
Finance lease costs:			
Amortization of lease assets	Depreciation, depletion and amortization	1	3
Interest on lease liabilities	Interest expense, net of capitalized interest	1	1
Total finance lease costs		2	4
Short-term lease cost	Operating expenses	40	31
Variable lease cost	Operating expenses	9	16
Lease costs, gross		156	157
Less: Sublease income	Other revenue	45	48
Lease costs, net		$ 111	$ 109

The weighted-average remaining lease terms and weighted-average discount rates as of December 31, 2021 and 2020 were as follows:

	December 31, 2021	December 31, 2020
Weighted-average remaining lease term (years):		
Operating leases	19	22
Finance leases	29	9
Weighted-average discount rate (%):		
Operating leases	5 %	5 %
Finance leases	4 %	8 %

Cash flows and non-cash activity related to leases for the years ended December 31, 2021 and 2020 were as follows:

	Year Ended December 31, 2021	Year Ended December 31, 2020
Operating cash flows from operating leases	$ (147)	$ (117)
Lease assets obtained in exchange for new finance lease liabilities	9	—
Lease assets obtained in exchange for new operating lease liabilities	9	42

Maturities of lease liabilities as of December 31, 2021 are as follows:

	Operating leases	Finance leases	Total
2022	$ 90	$ 4	$ 94
2023	86	1	87
2024	82	—	82
2025	78	—	78
2026	75	—	75
Thereafter	1,064	15	1,079
Total lease payments	1,475	20	1,495
Less: present value discount	613	6	619
Present value of lease liabilities	$ 862	$ 14	$ 876

Lessor Accounting

Sunoco LP leases or subleases a portion of its real estate portfolio to third-party companies as a stable source of long-term revenue. Sunoco LP's lessor and sublease portfolio consists mainly of operating leases with convenience store operators. At this time, most lessor agreements contain five-year terms with renewal options to extend and early termination options based on established terms specific to the individual agreement.

Sunoco LP's future minimum operating lease payments receivable as of December 31, 2021 are as follows:

	Lease Payments
2022	$ 84
2023	47
2024	3
2025	2
2026	1
Thereafter	5
Total undiscounted cash flows	$ 142

14. DERIVATIVE ASSETS AND LIABILITIES:

Commodity Price Risk

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

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

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

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

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

We use 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:

	December 31, 2021		December 31, 2020	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
(Trading)				
Natural Gas (BBtu):				
Fixed Swaps/Futures	585	2022-2023	1,603	2021-2022
Basis Swaps IFERC/NYMEX[(1)]	(66,665)	2022	(44,225)	2021-2022
Power (Megawatt):				
Forwards	653,000	2023-2029	1,392,400	2021-2029
Futures	(604,920)	2022-2023	18,706	2021-2022
Options – Puts	(7,859)	2022	519,071	2021
Options – Calls	(30,932)	2022	2,343,293	2021
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	6,738	2022-2023	(29,173)	2021-2022
Swing Swaps IFERC	(106,333)	2022-2023	11,208	2021
Fixed Swaps/Futures	(63,898)	2022-2023	(53,575)	2021-2022
Forward Physical Contracts	(5,950)	2023	(11,861)	2021
NGL (MBbls) – Forwards/Swaps	8,493	2022-2024	(5,840)	2021-2022
Crude (MBbls) – Forwards/Swaps	3,672	2022-2023	—	—
Refined Products (MBbls) – Futures	(3,349)	2022-2023	(2,765)	2021
Fair Value Hedging Derivatives				
(Non-Trading)				
Natural Gas (BBtu):				
Basis Swaps IFERC/NYMEX	(40,533)	2022	(30,113)	2021
Fixed Swaps/Futures	(40,533)	2022	(30,113)	2021
Hedged Item – Inventory	40,533	2022	30,113	2021

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

Interest Rate Risk

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

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

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

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

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

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

Credit Risk and Customers

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

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

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

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

Derivative Summary

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

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	December 31, 2021	December 31, 2020	December 31, 2021	December 31, 2020
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$ 46	$ 25	$ (3)	$ (32)
	46	25	(3)	(32)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	173	90	(156)	(166)
Commodity derivatives	53	53	(52)	(71)
Interest rate derivatives	—	—	(387)	(448)
	226	143	(595)	(685)
Total derivatives	$ 272	$ 168	$ (598)	$ (717)

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

		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2021	December 31, 2020	December 31, 2021	December 31, 2020
Derivatives without offsetting agreements	Derivative liabilities	$ —	$ —	$ (387)	$ (448)
Derivatives in offsetting agreements:					
OTC contracts	Derivative assets (liabilities)	53	53	(52)	(71)
Broker cleared derivative contracts	Other current assets (liabilities)	219	115	(159)	(198)
		272	168	(598)	(717)
Offsetting agreements:					
Counterparty netting	Derivative assets (liabilities)	(43)	(44)	43	44
Counterparty netting	Other current assets (liabilities)	(150)	(64)	150	64
Total net derivatives		$ 79	$ 60	$ (405)	$ (609)

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

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

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2021	2020	2019
Derivatives not designated as hedging instruments:				
Commodity derivatives – Trading	Revenues	$ —	$ —	$ (3)
Commodity derivatives – Trading	Cost of products sold	(6)	8	21
Commodity derivatives – Non-trading	Cost of products sold	(141)	(34)	(100)
Interest rate derivatives	Gains (losses) on interest rate derivatives	61	(203)	(241)
Total		$ (86)	$ (229)	$ (323)

15. RETIREMENT BENEFITS:

Savings and Profit Sharing Plans

We and our subsidiaries sponsor defined contribution savings and profit sharing plans, which collectively cover virtually all eligible employees, including those of Lake Charles LNG, Sunoco LP and USAC. Employer matching contributions are calculated using a formula based on employee contributions. We and our subsidiaries made matching contributions of $65 million, $35 million and $66 million to these 401(k) savings plans for the years ended December 31, 2021, 2020 and 2019, respectively.

As a result of the economic conditions in 2020, effective June 8, 2020, the Partnership ceased employer matching and profit sharing contributions through December 31, 2020. The Partnership resumed all such contributions in 2021.

Pension and Other Postretirement Benefit Plans

Panhandle

Postretirement benefits expense for the years ended December 31, 2021, 2020, and 2019 reflect the impact of changes Panhandle or its affiliates adopted as of September 30, 2013, to modify its retiree medical benefits program, effective January 1, 2014. The modification placed all eligible retirees on a common medical benefit platform, subject to limits on Panhandle's annual contribution toward eligible retirees' medical premiums. Prior to January 1, 2013, affiliates of Panhandle offered postretirement health care and life insurance benefit plans (other postretirement plans) that covered substantially all employees. Effective January 1, 2013, participation in the plan was frozen and medical benefits were no longer offered to non-union employees. Effective January 1, 2014, retiree medical benefits were no longer offered to union employees.

Effective January 1, 2018, the plan was amended to extend coverage to a closed group of former employees based on certain criteria.

ETC Sunoco

ETC Sunoco has a plan which provides health care benefits for substantially all of its current retirees. The cost to provide the postretirement benefit plan is shared by ETC Sunoco. and its retirees. Access to postretirement medical benefits was phased out or eliminated for all employees retiring after July 1, 2010. ETC Sunoco has established a trust for its postretirement benefit liabilities. The funding of the trust eliminated substantially all of ETC Sunoco's future exposure to variances between actual results and assumptions used to estimate retiree medical plan obligations.

SemGroup

SemGroup sponsors two defined benefit pension plans and a supplemental defined benefit pension plan (collectively, the "SemGroup Plans") for certain employees. The SemGroup Plans are closed to new participants and do not accrue any additional benefits.

Obligations and Funded Status

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table contains information at the dates indicated about the obligations and funded status of pension and other postretirement plans on a combined basis:

	December 31, 2021			December 31, 2020		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 55	$ 31	$ 208	$ 52	$ 34	$ 208
Service cost	—	—	1	—	—	1
Interest cost	1	1	4	2	1	5
Benefits paid, net	(2)	(4)	(16)	(2)	(5)	(16)
Actuarial (gain) loss and other	(2)	(2)	(2)	5	1	10
Settlements	(2)	—	—	(2)	—	—
Benefit obligation at end of period	50	26	195	55	31	208
Change in plan assets:						
Fair value of plan assets at beginning of period	45	—	291	43	—	270
Return on plan assets and other	2	—	26	5	—	28
Employer contributions	1	—	10	1	—	9
Benefits paid, net	(2)	—	(16)	(2)	—	(16)
Settlements	(2)	—	—	(2)	—	—
Fair value of plan assets at end of period	44	—	311	45	—	291
Amount underfunded (overfunded) at end of period	$ 6	$ 26	$ (116)	$ 10	$ 31	$ (83)
Amounts recognized in the consolidated balance sheets consist of:						
Non-current assets	$ —	$ —	$ 138	$ —	$ —	$ 108
Current liabilities	—	(4)	(2)	—	(4)	(2)
Non-current liabilities	(6)	(22)	(20)	(10)	(27)	(23)
	$ (6)	$ (26)	$ 116	$ (10)	$ (31)	$ 83
Amounts recognized in accumulated other comprehensive income (loss) (pre-tax basis) consist of:						
Net actuarial gain (loss)	$ —	$ 1	$ (27)	$ —	$ 2	$ (18)
Prior service cost	—	—	19	—	—	21
	$ —	$ 1	$ (8)	$ —	$ 2	$ 3

The following table summarizes information at the dates indicated for plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2021			December 31, 2020		
	Pension Benefits			Pension Benefits		
	Funded Plans	Unfunded Plans	Other Postretirement Benefits	Funded Plans	Unfunded Plans	Other Postretirement Benefits
Projected benefit obligation	$ 50	$ 26	N/A	$ 55	$ 31	N/A
Accumulated benefit obligation	50	26	195	55	31	208
Fair value of plan assets	44	—	311	45	—	291

Components of Net Periodic Benefit Cost

	December 31, 2021		December 31, 2020	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Net periodic benefit cost:				
Service cost	$ —	$ 1	$ —	$ 1
Interest cost	2	4	3	5
Expected return on plan assets	(2)	(11)	(2)	(11)
Prior service cost amortization	—	19	—	19
Net periodic benefit cost	$ —	$ 13	$ 1	$ 14

Assumptions

The weighted-average assumptions used in determining benefit obligations at the dates indicated are shown in the table below:

	December 31, 2021		December 31, 2020	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	2.79 %	2.24 %	2.40 %	2.04 %

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	December 31, 2021		December 31, 2020	
	Pension Benefits	Other Postretirement Benefits	Pension Benefits	Other Postretirement Benefits
Discount rate	2.57 %	2.18 %	3.05 %	2.94 %
Expected return on assets:				
Tax exempt accounts	4.76 %	7.00 %	4.57 %	7.00 %
Taxable accounts	—	4.75 %	—	4.75 %

The long-term expected rate of return on plan assets was estimated based on a variety of factors including the historical investment return achieved over a long-term period, the targeted allocation of plan assets and expectations concerning future returns in the marketplace for both equity and fixed income securities. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend weighted-average rates used to measure the expected cost of benefits covered by the plans are shown in the table below:

	December 31,	
	2021	2020
Health care cost trend rate	7.14 %	7.30 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.95 %	4.82 %
Year that the rate reaches the ultimate trend rate	2028	2027

Changes in the health care cost trend rate assumptions are not expected to have a significant impact on postretirement benefits.

Plan Assets

For the Panhandle plans, the overall investment strategy is to maintain an appropriate balance of actively managed investments with the objective of optimizing longer-term returns while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its other postretirement plan asset portfolio, Panhandle has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75%.

The investment strategy of ETC Sunoco funded defined benefit plans is to achieve consistent positive returns, after adjusting for inflation, and to maximize long-term total return within prudent levels of risk through a combination of income and capital appreciation. The objective of this strategy is to reduce the volatility of investment returns and maintain a sufficient funded status of the plans. In anticipation of the pension plan termination, ETC Sunoco targeted the asset allocations to a more stable position by investing in growth assets and liability hedging assets.

The fair value of the pension plan assets by asset category at the dates indicated is as follows:

		Fair Value Measurements at December 31, 2021		
	Fair Value Total	Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 1	$ 1	$ —	$ —
Mutual funds [(1)]	24	24	—	—
Fixed income securities	19	—	19	—
Total	$ 44	$ 25	$ 19	$ —

(1) Comprised of approximately 100% equities as of December 31, 2021.

		Fair Value Measurements at December 31, 2020		
	Fair Value Total	Level 1	Level 2	Level 3
Asset Category:				
Cash and cash equivalents	$ 1	$ 1	$ —	$ —
Mutual funds [(1)]	20	20	—	—
Fixed income securities	24	—	24	—
Total	$ 45	$ 21	$ 24	$ —

(1) Comprised of approximately 100% equities as of December 31, 2020.

The fair value of other postretirement plan assets by asset category at the dates indicated is as follows:

	Fair Value Total		Fair Value Measurements at December 31, 2021					
			Level 1		Level 2		Level 3	
Asset category:								
Cash and cash equivalents	$	22	$	22	$	—	$	—
Mutual funds[1]		175		175		—		—
Fixed income securities		114		—		114		—
Total	$	311	$	197	$	114	$	—

(1) Primarily composed of market index funds as of December 31, 2021.

	Fair Value Total		Fair Value Measurements at December 31, 2020					
			Level 1		Level 2		Level 3	
Asset category:								
Cash and cash equivalents	$	18	$	18	$	—	$	—
Mutual funds[1]		202		202		—		—
Fixed income securities		71		—		71		—
Total	$	291	$	220	$	71	$	—

(1) Primarily composed of market index funds as of December 31, 2020.

The Level 1 plan assets are valued based on active market quotes. The Level 2 plan assets are valued based on the net asset value per share (or its equivalent) of the investments, which was not determinable through publicly published sources but was calculated consistent with authoritative accounting guidelines.

Contributions

We expect to contribute $5 million to pension plans and $8 million to other postretirement plans in 2022. The cost of the plans are funded in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments

The Partnership's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below:

Years	Pension Benefits - Funded Plans		Pension Benefits - Unfunded Plans		Other Postretirement Benefits (Gross, Before Medicare Part D)	
2022	$	4	$	4	$	18
2023		3		4		17
2024		3		3		16
2025		2		3		15
2026		2		2		14
2027 – 2031		11		7		57

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Panhandle does not expect to receive any Medicare Part D subsidies in any future periods.

16. REPORTABLE SEGMENTS:

Our reportable segments currently reflect the following segments, which conduct their business primarily in the United States:

- 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 reflected in crude sales and gathering, transportation and other fees. 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.

We report Segment Adjusted EBITDA as a measure of segment performance. We define Segment 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. Segment 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:

	Years Ended December 31,		
	2021	2020	2019
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$ 7,307	$ 2,312	$ 2,749
Intersegment revenues	1,264	232	350
	8,571	2,544	3,099
Interstate transportation and storage:			
Revenues from external customers	1,802	1,841	1,941
Intersegment revenues	39	20	22
	1,841	1,861	1,963
Midstream:			
Revenues from external customers	2,620	1,944	2,280
Intersegment revenues	8,696	3,082	3,751
	11,316	5,026	6,031
NGL and refined products transportation and services:			
Revenues from external customers	16,989	8,501	9,920
Intersegment revenues	2,972	2,012	1,721
	19,961	10,513	11,641
Crude oil transportation and services:			
Revenues from external customers	17,442	11,674	18,447
Intersegment revenues	4	5	—
	17,446	11,679	18,447
Investment in Sunoco LP:			
Revenues from external customers	17,571	10,653	16,590
Intersegment revenues	25	57	6
	17,596	10,710	16,596
Investment in USAC:			
Revenues from external customers	621	655	678
Intersegment revenues	12	12	20
	633	667	698
All other:			
Revenues from external customers	3,065	1,374	1,608
Intersegment revenues	411	464	81
	3,476	1,838	1,689
Eliminations	(13,423)	(5,884)	(5,951)
Total revenues	$ 67,417	$ 38,954	$ 54,213

	Years Ended December 31,		
	2021	2020	2019
Cost of products sold:			
Intrastate transportation and storage	$ 4,769	$ 1,478	$ 1,909
Interstate transportation and storage	11	—	—
Midstream	8,569	2,598	3,577
NGL and refined products transportation and services	16,248	7,139	8,393
Crude oil transportation and services	14,759	8,838	14,832
Investment in Sunoco LP	16,246	9,654	15,380
Investment in USAC	85	82	91
All other	3,068	1,527	1,504
Eliminations	(13,360)	(5,829)	(5,885)
Total cost of products sold	$ 50,395	$ 25,487	$ 39,801

	Years Ended December 31,		
	2021	2020	2019
Depreciation, depletion and amortization:			
Intrastate transportation and storage	$ 191	$ 185	$ 184
Interstate transportation and storage	457	411	387
Midstream	1,190	1,140	1,066
NGL and refined products transportation and services	778	667	613
Crude oil transportation and services	588	640	437
Investment in Sunoco LP	177	189	181
Investment in USAC	239	239	231
All other	197	207	48
Total depreciation, depletion and amortization	$ 3,817	$ 3,678	$ 3,147

	Years Ended December 31,		
	2021	2020	2019
Equity in earnings (losses) of unconsolidated affiliates:			
Intrastate transportation and storage	$ 20	$ 18	$ 18
Interstate transportation and storage	140	17	222
Midstream	24	24	20
NGL and refined products transportation and services	51	60	53
Crude oil transportation and services	10	(2)	(1)
All other	1	2	(10)
Total equity in earnings of unconsolidated affiliates	$ 246	$ 119	$ 302

	Years Ended December 31,		
	2021	2020	2019
Segment Adjusted EBITDA:			
Intrastate transportation and storage	$ 3,483	$ 863	$ 999
Interstate transportation and storage	1,515	1,680	1,792
Midstream	1,868	1,670	1,602
NGL and refined products transportation and services	2,828	2,802	2,666
Crude oil transportation and services	2,023	2,258	2,898
Investment in Sunoco LP	754	739	665
Investment in USAC	398	414	420
All Other	177	105	98
Total Segment Adjusted EBITDA	13,046	10,531	11,140
Depreciation, depletion and amortization	(3,817)	(3,678)	(3,147)
Interest expense, net of interest capitalized	(2,267)	(2,327)	(2,331)
Impairment losses	(21)	(2,880)	(74)
Gains (losses) on interest rate derivatives	61	(203)	(241)
Non-cash compensation expense	(111)	(121)	(113)
Unrealized gains (losses) on commodity risk management activities	162	(71)	(5)
Inventory valuation adjustments	190	(82)	79
Losses on extinguishments of debt	(38)	(75)	(18)
Adjusted EBITDA related to unconsolidated affiliates	(523)	(628)	(626)
Equity in earnings of unconsolidated affiliates	246	119	302
Impairment of investments in unconsolidated affiliates	—	(129)	—
Other, net	(57)	(79)	54
Income before income tax expense	6,871	377	5,020
Income tax expense	(184)	(237)	(195)
Net income	$ 6,687	$ 140	$ 4,825

	December 31,		
	2021	2020	2019
Segment assets:			
Intrastate transportation and storage	$ 7,322	$ 6,308	$ 6,648
Interstate transportation and storage	17,774	17,582	18,111
Midstream	21,960	18,583	20,332
NGL and refined products transportation and services	28,160	21,423	19,145
Crude oil transportation and services	19,649	17,960	22,933
Investment in Sunoco LP	5,815	5,267	5,438
Investment in USAC	2,768	2,949	3,730
All other and eliminations	2,515	5,072	2,636
Total segment assets	$ 105,963	$ 95,144	$ 98,973

	Years Ended December 31,		
	2021	2020	2019
Additions to property, plant and equipment [1]:			
Intrastate transportation and storage	$ 52	$ 49	$ 124
Interstate transportation and storage	159	150	375
Midstream	484	487	827
NGL and refined products transportation and services	751	2,403	2,976
Crude oil transportation and services	343	291	403
Investment in Sunoco LP	174	124	148
Investment in USAC	60	119	200
All other	135	136	215
Total additions to property, plant and equipment [1]	$ 2,158	$ 3,759	$ 5,268

[1] Excluding acquisitions, net of contributions in aid of construction costs (capital expenditures related to the Partnership's proportionate ownership on an accrual basis).

	December 31,		
	2021	2020	2019
Investments in unconsolidated affiliates:			
Intrastate transportation and storage	$ 110	$ 89	$ 88
Interstate transportation and storage	2,209	2,278	2,524
Midstream	101	110	112
NGL and refined products transportation and services	476	509	461
Crude oil transportation and services	—	22	242
All other	51	52	33
Total investments in unconsolidated affiliates	$ 2,947	$ 3,060	$ 3,460