Risk Factors Comparison 2024-02-16 to 2023-02-17 Form: 10-K

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The following is a summary of important risk factors that are specific to our business, industry and partnership structure that could materially impact our future performance and results of operations. These risk factors should be reviewed when considering an investment in our securities. These are not all the risks we face **.** ~~, and other~~ **Other** factors that we face in the ordinary course of business ~~,~~ that are currently considered immaterial or that are currently unknown to us may impact our future operations. Risk Factor Summary 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; • 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 recent increases in cost of capital resulting from changes in monetary policy by the Federal Reserve and / or changes in financial institutions' policies or practices concerning businesses linked to fossil fuels; • any increased costs or reduced demand for crude oil and natural gas as a result of the Inflation Reduction Act of 2022 (" IRA 2022 ") or otherwise; • 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. ~~Index to Financial Statements~~ 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; **Index to Financial Statements** • 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 **GHGs** ~~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~~ • **tax- exempt entities and non- U. S. Unitholders face unique tax issues from owning our units that may result in adverse tax consequences to them; and • the** treatment of **Energy Transfer Preferred Units is uncertain and** distributions on Energy Transfer Preferred Units **(** ~~as guaranteed payments for the~~ **other than Series I Preferred Units)** ~~use of capital is uncertain and such distributions~~ may not be eligible for the 20 % deduction for qualified publicly traded partnership income. Risk Factor Discussion The following discussion provides additional information regarding each of our risk factors listed above. In addition, Sunoco LP and USAC file Annual Reports on Form 10- K that include risk factors that can be reviewed for further information. Risk Relating to the Partnership' s Business 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 **IDRs** ~~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, geopolitical events such as the armed conflict in Ukraine and political instability in the Middle East, 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; • supply chain disruptions and inflation; • 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; • rising interest rates and slowing economic growth; • 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. Our business could be negatively impacted by inflationary pressures which may decrease our operating margins and increase working capital investments required to operate our business. The U. S. ~~economy has experienced rising~~ inflation **rate steadily rose** in **2021 and into** 2022 **before eventually declining throughout 2023** . A sustained increase in inflation may continue to increase our costs for labor, services, and materials **, which, in turn, could cause our operating costs and capital expenditures to increase** . Further, our producer suppliers and customers face inflationary pressures and resulting impacts, such as the tight labor market, availability of drilling and hydraulic fracturing equipment, and supply chain disruptions, which could increase the cost of production which in turn may limit the level of drilling activity in the regions in which we operate. Our throughput volumes may be impacted if producers are constrained. The rate and scope of these various inflationary factors may increase our operating costs and capital expenditures materially, which may not be readily recoverable in the prices of our services and may have an adverse effect on our results of operations and financial condition. **Additionally, the Federal Reserve and other central banks have implemented policies in an effort to curb inflationary pressure on the costs of goods and services across the U. S., including the significant increases in prevailing interest rates that occurred during 2022 and 2023 as a result of the 525 aggregate basis point increase in the federal funds rate, and the associated macroeconomic impact on slowdown in economic growth could negatively impact our business. While the Federal Reserve indicated in December 2023 that it may reduce benchmark interest rates in 2024, the continuation of rates at the current level could have the effects of raising the cost of capital and depressing economic growth, either of which — or the combination thereof — could hurt the financial and operating results of our business.** An impairment of goodwill and intangible assets could reduce our earnings. As of December 31, ~~2022~~ **2023** , our consolidated balance sheet reflected $ ~~2~~ **4** . **02 billion of goodwill and $** 6 ~~billion of goodwill and $ 5~~ . ~~4~~ **24** 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 ~~2022~~ **2023** , two customers accounted for approximately ~~42~~ **36** % of our intrastate transportation and storage revenues. During ~~2022~~ **2023** , four customers collectively accounted for ~~39~~ **30** % of our interstate transportation and storage revenues. Certain of our joint ventures also depend on key customers. Citrus has long- term agreements with its top two customers which accounted for 52 % of its ~~2022~~ **2023** 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. Severe market disruptions could cause some of our counterparties 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 gas pipelines, the FERC commenced a proceeding to determine whether the public interest requires abrogation or modification of a firm 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 required abrogation or modification of the subject firm transportation agreement. The shipper subsequently filed for bankruptcy. Thereafter, on July 19, 2022, the Fifth Circuit Court of Appeals rejected FERC' s jurisdictional basis for its earlier public interest decision, vacated the November 9, 2020 order and a settlement has been reached regarding the agreement in the underlying bankruptcy proceeding. We will attempt to remarket the subject capacity and, depending on the availability of alternatives to our services, any resulting contracts may have terms that are less favorable to us than the former shipper' s contract. 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, ~~2022~~ **2023** , approximately ~~11~~ **10** % 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 **or malfeasance** by our or our service providers' employees and contractors (e. g., due to social engineering or phishing attacks). In addition, ~~a new development similar to the COVID- 19 pandemic could present additional operational and cybersecurity risks to our information technology infrastructure and physical assets if our providers begin or resume~~ work- from- home arrangements **may present additional operational and cybersecurity risks to our information**

technology infrastructure and physical assets . We and certain of our service providers have, from time to time, been subject to ~~cyberattacks~~ **cyber attacks** and security incidents. The frequency and magnitude of ~~cyberattacks~~ **cyber attacks** is ~~expected to increase~~ **increasing** and attackers are becoming more sophisticated **. Cyber attacks, including, but not limited to, malicious software, surveillance, credential stuffing, spear phishing, social engineering, use of deepfakes (i. e., highly realistic synthetic media generated by artificial intelligence), attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data, are evolving** . 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, **data loss or corruption, misdirected wire transfers,** ~~and~~ - **an inability to maintain our books and records or an inability to prevent environmental damage, any or all of which could, in turn,** have a material adverse effect on our operations, financial position and results of operations. A successful ~~cyberattack~~ **cyber attack** 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, **significant litigation costs,** 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 **and data privacy laws or** 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, which is currently the busiest port in the U. S. by waterborne tonnage and which has increased volumes in each of the last two years, 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. 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. 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, ~~2022~~ **2023** , we had approximately $ ~~48~~ **52** . ~~26~~ **39** 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. **As a result of Sunoco LP' s previously announced acquisition of NuStar, which is expected to close in the second quarter of 2024, Sunoco LP expects to assume NuStar' s debt and issue additional debt, aggregating approximately $ 4. 2 billion. This additional debt may accelerate any of the risks discussed above.** 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, including the significant increases in prevailing interest rates as a result of changes in federal monetary and fiscal policy. Approximately $ 3. ~~16~~ **29** billion of our consolidated debt as of December 31, ~~2022~~ **2023** 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. 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; **• because of recent heightened antitrust focus in the energy industry creating potential risk, expense and delays in connection with prospective acquisitions and consolidations;** or • because we are outbid by competitors **, particularly as a trend of consolidation within the energy industry continues** , 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~~ **may** require significant amounts of debt and equity financing, which may not be available to us on acceptable terms, or at all. We **may** ~~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. The Inflation Reduction Act of 2022 could decrease demand for crude oil and natural gas and could impose new costs on our operations. In August 2022, President Biden signed the IRA 2022, which contains hundreds of billions in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and carbon capture and sequestration, amongst other provisions. In addition, the IRA 2022 imposes the first- ever federal fee on the emission of **GHGs** ~~greenhouse gases~~ through a methane emissions charge. The IRA 2022 amends the federal Clean Air Act to impose a fee on the emission of methane from sources required to report their **GHG** ~~greenhouse gas~~ emissions to the EPA, including those sources in the onshore petroleum and natural gas production categories. The methane emissions charge ~~would start~~ **started** in calendar year 2024 at $ 900 per ton of methane, ~~increase~~ **increases** to $ 1, 200 in 2025, and **will** be set at $ 1, 500 for 2026 and each year after. Calculation of the fee is based on certain thresholds established in the IRA 2022. In addition, the multiple incentives offered for various clean energy industries referenced above could decrease demand for crude oil and natural gas, increase our compliance and operating costs and consequently adversely affect our business. 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. Any changes to the USACE NWP program that exclude our projects from coverage could require us to reroute pipeline projects, or seek individual permits that involve longer permitting timelines, leading to construction delays. 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 **offtake** ~~off- take~~ of LNG on terms sufficient to support the financial viability of the project. Lake Charles LNG Export, 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 **offtake** ~~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~~ **In December 2015, the FERC authorized** Lake Charles LNG Export ~~has received~~ **to site, construct and operate the liquefaction project subject to various condition, including a condition requiring all phases of the liquefaction project to be completed and in- service within five years of the date of the FERC authorization 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. In December 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. In May 2022, the FERC granted a second extension of time until and including December 16, 2028 to complete construction of the liquefaction facilities modifications and place the facilities into service. The export of LNG produced by any liquefaction facility in the United States requires export** authorization from the DOE **. The NGA requires the DOE to approve applications for LNG exports unless such approval would be " inconsistent with the public interest. " In March 2013, Lake Charles LNG Export obtained a DOE authorization** to export LNG to ~~non-~~ **countries with which the United States has or will have** Free Trade Agreements (" ~~non-~~ FTA ") ~~countries,~~ **for trade in natural gas (** the **"** ~~non-~~ FTA ~~authorization~~ **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~~ **. In July 2016,** Lake Charles LNG Export ~~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~~ **obtained a conditional DOE authorization** to ~~our Trunkline pipeline facilities~~ **export LNG to countries** that **do not have** ~~connect to our Lake Charles facility and~~ - **an FTA** ~~additionally requires execution of a transportation contract~~ for **trade in** natural gas **(** ~~supply to~~ the ~~liquefaction facility prior~~ **" Non- FTA Authorization ") subject** to **commencement** ~~the initiation~~ of **exports no later than** ~~construction of the liquefaction facility. On~~ December ~~5, 2019, the FERC granted an extension of time until and including December 16, 2025~~ **2020** ~~, to complete construction of the liquefaction project and pipeline facilities modifications and place the facilities into service~~ . ~~On January 31, 2022,~~ Lake Charles LNG Export ~~filed seeking~~ **applied for** an extension of ~~time until and including~~ **the deadline to commerce exports under the Non- FTA Authorization to** December ~~16, 2028~~ **2025 and the DOE approved such extension request in October 2020. Lake Charles LNG Export applied for a second extension of the deadline to commence exports and in April 2023 the DOE denied this request in connection with a new DOE policy related to extension requests. In light of this new policy, in August 2023, Lake Charles LNG Export applied for a new Non- FTA Authorization which, if approved, would provide for a new deadline to commence exports to Non- FTA countries, which deadline would be seven years from the date of such approval. In January 2024, the Biden administration announced a moratorium on the approval of LNG export authorizations by the DOE and instructed the DOE to conduct studies related to the cumulative impact of LNG exports on domestic natural gas prices, climate change and other matters. The Biden administration stated that these studies were necessary to enable the DOE to make determinations related to the statutory " public interest " standard. The DOE has stated that these studies will take several months** to complete ~~construction of~~ **, after which a draft policy statement will be made available for public comment prior to finalizing the policy statement. This process is not expected to be completed prior to the U. S. Presidential election in November 2024. Based on this action by the Biden administration,** ~~the~~ **there is uncertainty as to the ultimate determinations by the DOE with respect to whether the export of LNG from a specific** liquefaction ~~facilities~~ **facility** ~~modifications and place~~ **, such as** the **proposed Lake Charles LNG** ~~facilities~~ **facility** ~~into service~~ **, will be considered " not inconsistent with the public interest, " the applicable standard for approval under the NGA** . ~~The FERC issued~~ **Accordingly, there** ~~an~~ **can** ~~order granting the extension~~ **be no assurance as to whether Lake Charles LNG Export will receive approval** of ~~time request~~ **its application for a** ~~on~~ **Non - FTA Authorization** ~~May 6, 2022~~ . 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~~ **may** ~~experiencing~~ **experience** 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 ~~.~~ ~~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. On September 21, 2022, the Court entered a final judgment against the Energy Transfer Defendants in the amount of approximately $ 601 million plus post- judgment interest at a rate of 3. 5 % per year. The Energy Transfer Defendants filed the notice of appeal of this matter on October 21, 2022 and filed their opening brief in support of their appeal on December 30, 2022. Williams filed their answering brief on January 20, 2023, and the Energy Transfer Defendants filed their reply brief on February 6, 2023~~ . 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, followed by a permanent injunction in August 2022, 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. In 2022, the recommendations in this report resulted in a reduction in the volume of onshore land held for lease and an increased royalty rate **, and in 2023, the DOI proposed a rule to modernize the fiscal terms of the leasing program** . 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, in November 2022, the BLM proposed a rule that would limit flaring from well sites on federal lands, as well as allow the delay or denial of permits if the BLM finds that an operator' s methane waste minimization plan is insufficient. In addition, the Colorado **Energy and Carbon Management Commission (formerly 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 **, and is considering draft rules regarding the cumulative impacts of oil and gas projects** ; 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 its 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. On January 20, 2022, the Standing Rock Sioux Tribe withdrew as a cooperating agency on the draft EIS, prompting the USACE to temporarily pause on the draft EIS. **On September 8, 2023** ~~Although we are not certain as to the timeline~~ , the USACE ~~now estimates~~ **published the Draft EIS. Comments to the Draft EIS were due on December 13, 2023. The USACE anticipates** that ~~the draft~~ **a Final** EIS ~~will~~ **and Record of Decision would** be **issued** ~~published sometime~~ in ~~the spring of 2023~~ **2024** . For further information, see Note 11 to our consolidated financial statements included in " Item 8. Financial Statements and Supplementary Data " in this **annual** 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 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 an order issued **on** January 16, 2019, the FERC initiated a review of Panhandle' s **then** 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 **NGA** ~~Natural Gas Act~~ Section 5 and Section 4 proceedings were consolidated by order of the Chief Judge on October 1, 2019. The initial decision by the administrative law judge was issued on March 26, 2021 ~~. On April 26~~ , **and** ~~2021, Panhandle filed its brief~~ on ~~exceptions to the initial decision. On May 17, 2021, Panhandle filed its brief opposing exceptions in this proceeding. On~~ December 16, 2022, the FERC issued its order on **the initial decision. On January 17, 2023, Panhandle and the Michigan Public Service Commission each filed a request for rehearing of FERC' s order on the initial decision, which were denied by operation of law as of February 17, 2023. On March 23, 2023, Panhandle appealed these orders to the United States Court of Appeals for the District of Columbia Circuit (" Court of Appeals "), and the Michigan Public Service Commission also subsequently appealed these orders. On April 25, 2023, the Court of Appeals consolidated** Panhandle' s **and Michigan Public Service Commission' s appeals and stayed the consolidated appeal proceeding while the FERC further considered the requests for rehearing of its December 16, 2022 order. On September 25, 2023, the FERC issued its order addressing arguments raised on rehearing and compliance, which denied our requests for rehearing. Panhandle has timely filed its Petition for Review with the Court of Appeals regarding the September 25, 2023 order. On October 25, 2023, Panhandle filed a limited request for rehearing of the September 25 order addressing arguments raised on rehearing and compliance, which was subsequently denied by operation of law on November 27, 2023. On November 30, 2023, Panhandle submitted a refund report regarding the consolidated** rate ~~case~~ **proceedings, which has been protested by several parties** . On January ~~17~~ **5, 2024, the FERC issued a second order addressing arguments raised on rehearing in which it modified certain discussion from its September 25** , 2023 ~~,~~ **order and sustained its prior conclusions.** Panhandle **has timely** filed its ~~request~~ **Petition** for **Review with the Court of Appeals** ~~rehearing~~ **regarding** ~~in~~ the ~~proceeding~~ **January 5, 2024 order** . On July 1, 2022, Transwestern filed a rate case pursuant to Section 4 of the **NGA** ~~Natural Gas Act~~ . By order dated September 9, 2022, a procedural schedule was adopted in this proceeding, setting the commencement of the hearing for June 22, 2023 with an initial decision anticipated by November 15, 2023. By a subsequent order dated February 14, 2023, the procedural schedule was suspended based on representations that the participants have reached an agreement in principle to resolve all issues in this proceeding and a settlement is being prepared for filing at FERC. **A settlement was filed with the FERC on April 5, 2023, and approved by order dated June 30, 2023.** On December 1, 2022, Sea Robin filed a general rate proceeding under Section 4 of the NGA reflecting a general rate increase for gathering and transportation services. A hearing in the proceeding is scheduled for October 24, 2023 with an initial decision anticipated by March 19, 2024 **. The parties have reached a settlement in the case, and the settlement was filed with the FERC on December 29, 2023** . 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; • siting and 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 **NGA** ~~Natural Gas Act~~ . A technical conference was held on November 19, 2021, and post- technical conference comments were submitted to the FERC on January 7, 2022. On February 18, 2022, the FERC issued two new policy statements: (1) an Updated Policy Statement on the Certificate of New Interstate Natural Gas Facilities and (2) a Policy Statement on the Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews (" 2022 Policy Statements "), to be effective that same day. On March 24, 2022, the FERC issued an order designating the 2022 Policy Statements as draft policy statements, and requested further comments. The FERC stated that it will not apply the now draft 2022 Policy Statements to pending applications or applications to be filed at FERC until it issues any final guidance on these topics. Comments on the 2022 Policy Statements were due on

April 25, 2022, and reply comments were due on May 25, 2022. We are unable to predict what, if any, changes may be proposed as a result of the 2022 Policy Statements that might affect our natural gas pipeline or LNG facility projects, or when such new policies, if any, might become effective. We do not expect that any change in these policy statements would affect us in a materially different manner than any other natural gas pipeline company operating in the United States. 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. On October 20, 2022, the FERC issued a policy statement on the Standard Applied to Complaints Against Oil Pipeline Index Rate Changes to establish guidelines regarding how the FERC will evaluate shipper complaints against oil pipeline index rate increases. Specifically, the policy statement adopted the proposal in the FERC’ s earlier Notice of Inquiry issued on March 25, 2020 to eliminate the “ Substantially Exacerbate Test ” as the preliminary screen applied to complaints against index rate increases and instead adopt the proposal to apply the “ Percentage Comparison Test ” as the preliminary screen for both protests and complaints against index rate increases. At this time, we cannot determine the effect of a change in the FERC’ s preliminary screen for complaints against index rates changes, however, a revised screen would result in a threshold aligned with the existing threshold for protests against index rate increases. Any complaint or protest raised by a shipper could materially and adversely affect our financial condition, results of operations or cash flows. 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 FERC received requests for rehearing of its December 17, 2020 order and on January 20, 2022, granted rehearing and modified the oil index. Specifically, for the five- year period commencing July 1, 2021 and ending June 30, 2026, FERC- regulated liquids pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by PPI- FG minus 0. 21 %. FERC directed liquids pipelines to recompute their ceiling levels for July 1, 2021 through June 30, 2022, as well as the ceiling levels for the period July 1, 2022 to June 30, 2023, based on the new index level. Where an oil pipeline’ s filed rates exceed its ceiling levels, FERC ordered such oil pipelines to reduce the rate to bring it into compliance with the recomputed ceiling level to be effective March 1, 2022. Some parties sought rehearing of the January 20 order with FERC, which was denied by FERC on May 6, 2022. Certain parties have appealed the January 20 and May 6 orders. Such appeals remain pending at the D. C. Circuit. 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 pipeline systems of Enable Oklahoma Intrastate Transmission, LLC, Oasis Pipeline, LP, Houston Pipe Line Company LP, ETC Katy Pipeline, LLC, Energy Transfer Fuel, LP, Lobo Pipeline Company, LLC, Pelico Pipeline, LLC, Regency Intrastate Gas LP, Red Bluff Express Pipeline, LLC, Trans- Pecos Pipeline, LLC and Comanche Trail Pipeline, LLC 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 gathering pipelines 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. Energy Transfer GC NGL' s 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, Energy Transfer GC NGL' s 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 third final rule was published in August 2022, which adjusted the repair criteria for pipelines in HCAs, created new criteria for pipelines in non- HCAs, and strengthened integrity management assessment requirements, among other items. 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 March 2022, 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 $ 239, 142 per day, with a maximum of $ 2, 391, 412 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, PHMSA issued the three final rules discussed above, 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, suspension and debarment from federal contracting opportunities, the occurrence of delays in permitting and completion of projects, and the issuance of injunctive relief. For example, following a state grand jury investigation and the filing of charges alleging criminal misconduct involving the construction and related activities of the Mariner East 2 pipeline (" Mariner 2 "), in August 2022 we entered into a plea of no contest with the Pennsylvania Attorney General' s Office that requires us to pay fines to the Commonwealth, pay for independent evaluations of potential water quality impacts to residential water supplies and compensate any affected homeowners, and to also pay $ 10 million to support water quality improvement projects. 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. Subsequently, the EPA issued a Notice of Proposed Debarment (" NPD ") on October 28, 2022, arising from SPLP' s and ETC Northeast Pipeline, LLC' s nolo contendere plea agreements and convictions for violations of Pennsylvania' s Clean Streams Law related to the Revolution and Mariner 2 pipelines. The following entities were proposed for debarment: (1) SPLP (pleading entity); (2) ETC Northeast Pipeline, LLC (pleading entity); (3) Energy Transfer LP; (4) SemGroup LLC; and (5) LE GP, LLC. The NPD presently prevents the named entities from pursuing or renewing Federal government contracts or Federal financial assistance agreements. While we are engaging with the EPA to attempt to resolve the matter, at this time there can be no assurance that the EPA will not finalize a debarment applicable to the named entities for a set period of time, or expand the debarment to other Energy Transfer affiliates. Currently, none of the entities named in the NPD are party to any Federal government contracts or Federal financial assistance agreements. 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 interim estimate of the social cost of carbon has been subject to litigation in 2022, but is in use while litigation is pending. **The** EPA has also separately developed its own proposal for a social cost of carbon, which is significantly higher than that proposed by the Working Group. The EPA' s proposal is currently undergoing independent peer review and is not yet in use by the agency. 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 **GHGs** ~~greenhouse gases~~ 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 **GHG** ~~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. In August 2022, the IRA 2022 was signed into law, which appropriates significant federal funding for renewable energy initiatives and amends the federal Clean Air Act to impose a first- time fee on the emission of methane from sources required to report their GHG emissions to the EPA. The IRA 2022 imposes a methane emissions charge on sources required to report their GHG emissions to the EPA, which ~~would start~~ **started** in calendar year 2024 at $ 900 per ton of methane, ~~increase~~ **increases** to $ 1, 200 in 2025, and **will** be set at $ 1, 500 for 2026 and each year after. Calculation of the fee is based on certain thresholds established in the IRA 2022. 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 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~~ **December** ~~2021~~ **2023** , the EPA issued a ~~proposed~~ **final** rule that ~~, if finalized, would establish~~ **established** 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~~ **will** 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. ~~In November 2022, the EPA released its supplemental methane proposal. Among other items, the proposal sets forth specific revisions strengthening the first nationwide emission guidelines for states to limit methane emissions from existing crude oil and natural gas facilities.~~ The ~~proposal~~ **December 2023 rule** also revises requirements for fugitive emissions monitoring and repair as well as equipment leaks and the frequency of monitoring surveys, establishes a " super- emitter " response program to timely mitigate emissions events, **triggering certain response and repair requirements,** and provides additional options for the use of advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions. **Fines** ~~The proposal is currently subject to public comment~~ and ~~is expected to~~ **penalties for violations of these rules can** be **substantial** ~~finalized in 2023~~ . 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. At ~~COP27~~ **the 27th Conference of the Parties** in Sharm El- Sheik in November 2022, countries reiterated the agreements from COP26 and were called upon to accelerate efforts toward the phase- out of fossil fuel subsidies. The United States also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane- intensity natural gas. **In December 2023, at COP28, parties signed onto an agreement to transition away from fossil fuels in energy systems and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for doing so was set.** Although no ~~firm commitment or~~ timeline to phase out or phase down all fossil fuels ~~was~~ **has been** made ~~at COP27~~ , there can be no guarantees that countries will not seek to implement ~~such~~ a **timeline** ~~phase out~~ in the future. 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. This pause was subsequently subject to a permanent injunction in August 2022, effectively halting implementation of the leasing suspension with respect to those leases canceled or postponed prior to March 24, 2021. 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 interim estimate of the social cost of carbon, $ 51 per ton, has been subject to litigation in 2022, but is in use while litigation is pending. 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. 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. In September 2022, the Federal Reserve announced that six of the United States' largest banks will participate in a pilot climate scenario analysis exercise, **which** ~~expected to be~~ launched in early 2023, to enhance the ability of firms and supervisors to measure and manage climate- related financial risk. While we cannot predict what polices may result from these developments, 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, in March 2022 the SEC released a proposed rule requiring climate disclosures, which is expected to be finalized in ~~early 2023~~ **2024** . 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, governmental incentives and funding such as those provided in the IRA 2022, 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 are pursuing various low- carbon opportunities such as renewable power generation, renewable fuels, and carbon capture and storage projects through our alternative energy initiatives to address potential energy transition related risks, we cannot guarantee that we will be able to execute these projects in a timely manner because of permitting, technology, or other risks or that such opportunities will ultimately be successful. 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. The Dodd- Frank Wall Street Reform and Consumer Protection Act (the " Dodd- Frank Act ") requires that certain classes of swaps be cleared on a derivatives clearing organization and traded on a designated contract markets 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~~ **April** ~~2020~~ **2023** , BOEM and BSEE published a ~~proposed~~ **final** rule regarding financial assurance requirements for offshore leases, particularly regarding requirements for bonds above base amounts prescribed by regulation **. In June 2023, BOEM issued a notice of proposed rulemaking seeking to modify its criteria for determining bonds and financial assurance for offshore oil and gas lessees and other operators, which generally imposes more stringent requirements for waiving supplemental bonding requirements and changes how BOEM calculates the amount of supplemental financial assurance required, amongst other matters** . 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 and permanent injunction in August 2022, effectively halting implementation of the leasing suspension. Additionally, provisions in the IRA 2022 require that particular offshore oil and gas lease sales under the 2017 – 2022 leasing program proceed, and the DOI has reinstated or announced plans for those sales. In ~~July~~ **September** ~~2022~~ **2023** , the DOI published a proposed **final** offshore leasing program for ~~2023~~ **2024** – ~~2028~~ **2029** , ~~although~~ **which was** ~~the~~ **then** ~~approval~~ **approved** ~~process is ongoing~~ **by the Secretary of the Interior** and ~~may be subject to change or challenge~~ **authorized three Gulf of Mexico leasing sales** . 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 **. For example, in 2023, the DOI proposed a rule to modernize the fiscal terms of the leasing program, increase costs associated with such leases and add new criteria for the DOI to consider when deciding whether to lease nominated lands** . 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. Issuance of Common 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 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; • 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; • 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. Our common ~~and~~ **units,** ~~series~~ **Series** ~~C, D and~~ E ~~preferred~~ **Preferred** ~~units~~ **Units and Series I Preferred Units** 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. 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, ~~2022~~ **2023** , the Partnership had outstanding ~~765~~ **833** , ~~896~~ **486** , ~~700~~ **004** 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~~ **9** , ~~2023~~ **2024** , Mr. Warren’ s combined common unit and Energy Transfer Class A Unit ownership results in a voting interest in the Partnership of 27 %. 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 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, ~~2022~~ **2023** , the directors and executive officers of our general partner owned approximately ~~11~~ **10** % of our Common Units. 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. In particular, our Five- Year Credit Facility ~~(as defined herein)~~ , limits our and certain of our subsidiaries' ability to make distributions. 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 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 **or a material shift toward electric or other alternative- power vehicles** , in the areas Sunoco LP serves would reduce their ability to make distributions to its unitholders.

For the year ended December 31, ~~2022~~ **2023**, sales of refined motor fuels accounted for approximately 98 % of Sunoco LP' s total revenues and ~~72~~ **69** % 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. **For example, in December 2021, the Biden Administration announced revised GHG emissions standards for light- duty vehicle fleets for Model Years 2023- 2026, which some manufacturers may meet by increasing fuel efficiency or increasing the prevalence of zero- emissions vehicles in their fleets. The Biden Administration has also set a goal for federal vehicle acquisitions to be 100 % zero- emissions vehicles by 2035, which may further influence the composition of vehicle fleets. Laws such as the Bipartisan Infrastructure Act and the IRA 2022 allocate funds to the development of electric vehicle infrastructure and provide incentives for consumers and manufacturers related to their use or development of electric vehicles, and the adoption rate of electric vehicles in the U. S. has continued to accelerate, with projections for the future rate of adoption in some reports more than doubling in recent years.** Any of these ~~outcomes~~ **actions** 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 ~~35~~ **33** % 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. In December 2022, the EPA released a proposed rule under the RFS for renewable fuel volumes for the years 2023- 2025 that further increases targets for the production of renewable fuels. Subject to certain limitations, EPA now has significant discretion to set renewable fuel targets under the RFS, which could result in increased compliance obligations on refiners and importers and transportation fuels. 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. **If third- party pipelines and other facilities interconnected to Sunoco LP' s fuel storage terminals and transmix processing facilities become partially or fully unavailable to transport refined products, Sunoco LP' s revenues could be adversely affected. Sunoco LP depends upon third- party pipelines and other facilities that provide delivery options to and from its fuel storage terminals and transmix processing facilities. Since Sunoco LP does not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within Sunoco LP' s control. If any of these third- party facilities become partially or fully unavailable, or if the quality specifications for their facilities change so as to restrict our ability to utilize them, Sunoco LP' s financial condition and results of operations could be adversely affected. The third parties on whom Sunoco LP relies for transportation services to its fuel storage terminals and transmix processing facilities are subject to complex federal, state, and other laws that could adversely affect Sunoco LP' s financial condition and results of operations. The operations of the third parties on whom Sunoco LP relies for transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third- party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that Sunoco LP pays for services. Similarly, a failure to comply with such laws and regulations by the third parties could have a material adverse effect on Sunoco LP' s financial condition and results of operations. Failure of Sunoco LP to complete its acquisition of NuStar and successfully integrate the businesses of Sunoco LP and NuStar in the expected time frame could negatively impact the price of Sunoco LP' s common units and have a material adverse effect on its results of operations, cash flows and financial position. If Sunoco LP' s acquisition of NuStar is not completed for any reason, including as a result of failure to obtain all requisite regulatory approvals or Sunoco LP' s unitholders failing to approve the applicable proposals, the anticipated benefits of the acquisition may not be realized or may take longer to realize than expected. The success of the merger will depend, in part, on the ability of Sunoco LP to realize the anticipated benefits from combining its business and NuStar. If Sunoco LP and NuStar are unable to successfully combine their businesses, the anticipated benefits of the merger 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. Additionally, Sunoco LP would be subject to a number of risks, including the following: • negative reactions from the financial markets, including negative impacts on the price of Sunoco LP' s common units; • negative reactions from Sunoco LP' s customers, distributors, suppliers, vendors, landlords, joint venture partners and / or other business partners; • Sunoco LP will still be obligated to pay certain significant costs relating to its acquisition of NuStar, such as legal, accounting, financing, advisory and / or printing fees; • Sunoco LP may be obligated to pay a termination fee as required by the merger agreement governing the acquisition; • the merger agreement governing the acquisition places certain restrictions on the conduct of Sunoco LP' s business, which may delay or prevent the undertaking of business opportunities that, absent the merger agreement governing the acquisition, may have been pursued; • matters relating to Sunoco LP' s acquisition of NuStar (including integration planning) require substantial commitments of time and resources by Sunoco LP' s management, which may have resulted in the distraction from ongoing business operations and pursuing other**

opportunities that could have been beneficial; • litigation related to any failure of Sunoco LP to complete its acquisition of NuStar or related to any enforcement proceeding commenced against Sunoco LP to perform its respective obligations under the merger agreement governing the acquisition; and • loss of key employees, the disruption of each of Sunoco LP' s and NuStar' s ongoing businesses and relationships with customers, or inconsistencies in their standards, controls, procedures and policies. If the acquisition is not completed, the risks described above may materialize and they may have a material adverse effect on Sunoco LP' s results of operations, cash flows, financial position and / or price of its common units. 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 more 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 initial terms between six months to 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, ~~2022~~ **2023** , approximately ~~29~~ **22** % 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. 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. 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~~ **proposals** have provided for the total elimination of the qualifying income exception upon which we rely for our partnership tax treatment **. Further, while Unitholders of publicly traded partnerships are, subject to certain limitations, entitled to a deduction equal to 20 % of their allocable share of a publicly traded partnership' s " qualified business income, " this deduction is scheduled to expire with respect to taxable years beginning after December 31, 2025. In addition, the U. S. Department of the Treasury has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to United States federal income tax laws or the U. S. Department of the Treasury' s interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future** . 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. **If** ~~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 these 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. **Additionally, all or part of any gain recognized by such tax- exempt organization upon a sale or other disposition of our units may be unrelated business taxable income and may 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. In addition to the withholding tax imposed on distributions of effectively connected income, distributions to a non- U. S. unitholder will also be subject to a 10 % withholding tax on the amount of any distribution in excess of our cumulative net income. We intend to treat all of our distributions as being in excess of our cumulative net income for such purposes and subject to such 10 % withholding tax. Accordingly, distributions to a non- U. S. unitholder will be subject to a combined withholding tax rate equal to the sum of the highest applicable effective tax rate and 10 %. 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. For a transfer of interests in a publicly traded partnership that is effected through a broker ~~on or after January 1, 2023~~ , the obligation to withhold 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, **we** ~~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, 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. **If our " business interest " is subject to limitation under these rules, our Unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us. The** ~~Treatment~~ **treatment** of **Energy Transfer Preferred Units is uncertain, and** distributions on Energy Transfer Preferred Units **(** ~~as guaranteed payments for the~~ **other than Series I Preferred Units)** ~~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~~ **With respect to Preferred Units (other than Series I Preferred Units), we** will treat Preferred Unitholders as partners for tax purposes and will treat distributions on ~~the~~ **such** Preferred Units as guaranteed payments for the use of capital that will generally be taxable to **such** Preferred Unitholders as ordinary income. Preferred Unitholders **of our Preferred Units (other than Series I Preferred Units)** 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 **of our Preferred Units (other than Series I Preferred Units)** 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 **such** Preferred Unitholders. If the Energy Transfer Preferred Units **(other than Series I 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 **for taxable years beginning after December 31, 2025** , the 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 **. With respect to Series I**

Preferred Units, we will treat distributions as distributions to a partner and will treat Preferred Unitholders that hold Series I Preferred Units (the " Series I Preferred Unitholders ") as receiving an allocable share of gross income from us, to the extent we have sufficient gross income to make such allocations. In the event there is not sufficient gross income to match such distributions, the distributions on the Series I Preferred Units would reduce the capital accounts of the Series I Preferred Units, requiring a subsequent allocation of income or gain to provide the Series I Preferred Units with their liquidation preference, if possible. However, if the IRS were to determine that such distributions were guaranteed payments for the use of capital, the distributions would generally be taxable to each of the Series I Preferred Unitholders as ordinary income and the Series I Preferred Unitholders would recognize taxable income from the accrual of such guaranteed payment (even in the absence of a contemporaneous cash distribution), as described above with respect to Preferred Units (other than Series I Preferred Units). If the Series I Preferred Units are not treated as partnership interests, they would likely constitute indebtedness for tax purposes, and distributions on the Series I Preferred Units likely would be treated as payments of interest by us to such Series I Preferred Unitholders . 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 **and the rules applicable in determining the exchanged tax basis of a Series I Preferred Unit received by a Unitholder pursuant to the Crestwood acquisition** , 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~~ **With respect to Preferred Units (other than Series I Preferred Units), 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. **With respect to Series I Preferred Units, virtually all of our gross income allocated to tax- exempt investors will be unrelated business taxable income and will be taxable to them.** 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.