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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2022

OR

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

Commission file number 001-04321

TXO Energy Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**32-0368858**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
400 West, 7th Street, Fort Worth, Texas	**76102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant’s telephone number, including area code: **(817) 334-7800**

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	TXO	New York Stock Exchange

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

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

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

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

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

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

Large accelerated filer	o	Accelerated filer	o
Non-accelerated filer	x	Smaller reporting company	o
		Emerging growth company	x

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

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

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. o

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant’s executive officers during the relevant recovery period pursuant to §240.10D-1(b). o

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

As of June 30, 2022, the last business day of the registrant’s most recently completed second quarter, there was no established public trading market for the registrant’s equity securities. The registrant’s Common Units began trading on The New York Stock Exchange on January 27, 2022. The registrant had 30,750,000 Common Units outstanding as of March 31, 2023.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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FORWARD-LOOKING STATEMENTS

Some of the information in this Annual Report on Form 10-K may contain “forward-looking statements.” All statements, other than statements of historical fact included in this Annual Report on Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report on Form 10-K, words such as “may,” “assume,” “forecast,” “could,” “should,” “will,” “plan,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “budget” and similar expressions are used to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events at the time such statement was made. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading “Risk Factors” included in this Annual Report on Form 10-K.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development and production of oil, natural gas and NGL. We disclose important factors that could cause our actual results to differ materially from our expectations as discussed under “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and elsewhere in this Annual Report on Form 10-K. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statement include:

- commodity price volatility;
- the impact of epidemics, outbreaks or other public health events, and the related effects on financial markets, worldwide economic activity and our operations;
- the impact of COVID-19, and governmental measures related thereto, on global demand for oil and natural gas and on the operations of our business;
- uncertainties about our estimated oil, natural gas and NGL reserves, including the impact of commodity price declines on the economic producibility of such reserves, and in projecting future rates of production;
- the concentration of our operations in the Permian Basin and the San Juan Basin;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- lack of transportation and storage capacity as a result of oversupply, government regulations or other factors;
- lack of availability of drilling and production equipment and services;
- potential financial losses or earnings reductions resulting from our commodity price risk management program or any inability to manage our commodity risks;
- failure to realize expected value creation from property acquisitions and trades;
- access to capital and the timing of development expenditures;
- environmental, weather, drilling and other operating risks;
- regulatory changes, including potential shut-ins or production curtailments mandated by the Railroad Commission of Texas;
- competition in the oil and natural gas industry;
- loss of production and leasehold rights due to mechanical failure or depletion of wells and our inability to re-establish their production;
- our ability to service our indebtedness;
- cost inflation;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the armed conflict in

Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;

- evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insider or other with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; and

- risks related to our ability to expand our business, including through the recruitment and retention of qualified personnel.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, our reserve and PV-10 estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report on Form 10-K occur, or should underlying assumptions prove to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report on Form 10-K are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report on Form 10-K.

Risk Factor Summary

An investment in our common units involves risks associated with our business, our partnership structure and the tax characteristics of our common units, among other things. You should carefully consider the risks described in “Risk Factors” and the other information in this Annual Report on Form 10-K before investing in our common units. Some of the most significant challenges and risks we face include the following:

Risks Related to Cash Distributions

- We may not have sufficient available cash to pay any quarterly distribution on our common units following the establishment of cash reserves and payment of expenses.

Risks Related to Our Business and the Oil, Natural Gas and NGL Industry

- The volatility of oil, natural gas and NGL prices due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.

- Unless we replace the reserves we produce, our revenues and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

- If commodity prices decline and remain depressed for a prolonged period, production from a significant portion of our properties may become uneconomic and cause downward adjustments of our reserve estimates and write downs of the value of such properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

- Drilling for and producing oil, natural gas and NGLs are high-risk activities with many uncertainties that could adversely affect our business, financial condition, results of operations and cash distributions to unitholders.

- We operate certain of our properties through a joint venture over which we have shared control.

- Declining general economic, business or industry conditions and inflation may have a material adverse effect on our results of operations, liquidity and financial condition.

- Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, or the threat thereof, could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.

- We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk.

- Our Credit Facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

- Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Risks Related to Environmental and Regulatory Matters

- We are subject to stringent federal, state and local laws and regulations related to environmental and occupational health and safety issues that could adversely affect the cost or feasibility of conducting our operations or expose us to significant liabilities.

- Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil, natural gas and NGL exploration and production activities, and reduce demand for the oil, natural gas and NGLs we produce.

Risks Inherent in an Investment in Us

- Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

- Our partnership agreement replaces our general partner’s fiduciary duties to us and our unitholders with contractual standards governing its duties, and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

- Our general partner may amend our partnership agreement, as it determines necessary or advisable, to permit the general partner to redeem the units of certain non-citizen unitholders.

- Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors (the “Board”), which could reduce the price at which our common units will trade.

- Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

- Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

- Control of our general partner may be transferred to a third party without unitholder consent.

- Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent.

- We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

- The NYSE does not require a publicly traded partnership like us to comply, and we do not intend to comply, with certain of its governance requirements generally applicable to corporations.

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service

were to treat us as a corporation for federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.

- Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Part I

Items 1 & 2. Business and Properties

Business Overview

We are focused on the acquisition, development, optimization and exploitation of conventional oil, natural gas, and natural gas liquid reserves in North America. Our management team has significant industry experience acquiring and exploiting conventional oil and natural gas properties in multiple resource plays and basins. As a result of such experience, our operations focus primarily on enhancing the development and operation of producing properties through our concentration on efficiency and optimizing exploitation of current wells. Our current acreage positions are concentrated in the Permian Basin of West Texas and New Mexico and the San Juan Basin of New Mexico and Colorado, each of which we believe is characterized by low geologic risk, low decline rates and high recoveries relative to drilling and completion costs.

Our partnership agreement requires us to distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner which we refer to as “available cash”. We believe the low decline nature of our reserves and the relatively low cost to maintain production combined with our zero to low leverage profile will support distributions to our unitholders. The amount of cash available for distribution with respect to any quarter, however, will be dependent on the then-prevailing commodity prices. To mitigate the risk associated with volatile commodity prices and to further enhance the stability of our cash flow available for distributions, from time to time we may opportunistically hedge a portion of our production volumes at prices we deem attractive to mitigate our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales. Nevertheless, our quarterly cash distributions may vary from quarter to quarter as a direct result of variations in the performance of our business, including those caused by fluctuations in the prices of oil and natural gas. Such variations may be significant and quarterly distributions paid to our unitholders may be zero.

We seek to maintain a flat to low growth production profile through a combination of low-risk development and exploitation of our existing properties, generally funded by cash flow from operating activities, and future acquisitions of producing properties. We believe this will allow us to increase our reserves and production and, over time, to increase distributions to our unitholders. To date we have been successful in offsetting the natural decline in production from reservoir depletion through acquisitions and drilling. Historically, funding sources for our capital expenditures, including acquisitions, have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. We expect to continue to fund our capital expenditures primarily with cash flow generated by operating activities, but may use borrowings under our Credit Facility in connection with acquisitions in particular. Additionally, we may seek to issue additional equity securities from time to time as market conditions allow to facilitate future acquisitions. Our development budget is approximately $30.0 - $35.0 million for 2023.

The members of our management team have an average of 32 years’ experience in the oil and gas industry. Our management team has successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets for more than 30 years, completing hundreds of acquisitions totaling over $15 billion. Additionally, our management team has collectively invested more than $500 million in us since our inception. We believe our management team has the experience, expertise and commitment to create significant value for our unitholders in the form of cash distributions combined with growth in revenues and production.

Our Business Strategies

Our primary business objective is to make increasing distributions to our unitholders over time. To achieve our objective, we intend to execute the following business strategies:

- **Focus on long-lived, low decline conventional assets.** We believe that by focusing on the exploitation of our existing assets, we can maintain current production using a portion of our operating cash flow, while utilizing the remainder of our operating cash flow to acquire additional assets to exploit and make distributions to our unitholders.

- **Maximize ultimate hydrocarbon recovery from our assets through enhancement and optimization of producing properties.** We continuously seek efficiencies in our drilling, completion and production techniques to optimize ultimate resource recoveries, rates of return and cash flows. We will continue to work to unlock additional value and will allocate capital towards next generation technologies where applicable. In addition, we intend to take advantage of under-development in basins where we operate by expanding our geologic investigation of additional producing horizons on our acreage and adjacent acreage. We seek to expand our development beyond our known productive areas to add reserves to our inventory at attractive all-in costs.

- **Focus on making cash distributions to, and providing long term value for, our unitholders.** Our primary goal is to maximize investor returns through cash distributions and flat to low production and reserves growth over time in support of our strategy as a "production and distribution" enterprise.

- **Maintain financial flexibility with a conservative capital structure and ample liquidity.** We intend to conduct our operations primarily through cash flow generated from operations with a focus on maintaining a disciplined balance sheet with little to no outstanding debt. Due to our strong operating cash flows and liquidity, we have substantial flexibility to fund our capital budget and to potentially accelerate our drilling program as conditions warrant. Our focus is on the economic extraction of hydrocarbons while maintaining a prudent leverage ratio and strong liquidity profile. Although we may use leverage to make accretive acquisitions, we will do so with the long-term goal of remaining substantially debt free. Further, we expect that our hedging strategy will reduce our exposure to commodity price volatility.

- **Execute attractive acquisitions and optimize assets through effective integration.** Our management team has a history of successfully identifying, acquiring and optimizing assets over the past three decades. We believe our acreage positions in the Permian Basin and San Juan Basin provide opportunities to increase production and reserves through the implementation of mechanical and operational improvements, workovers, behind-pipe completions, secondary and tertiary recovery operations, new development wells and other development activities. We plan to use the expertise of our management team to strategically acquire properties that complement our operations.

Our Strengths

We believe that the following strengths will allow us to successfully execute our business strategies:

- **Experienced and personally invested management team with an extensive track record of value creation.** We believe our management team's significant industry experience is a distinct competitive advantage. The members of our management team have an average of 32 years' experience in the oil and gas industry and have previously held executive roles at XTO Energy Inc. ("XTO"). Our management team has successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets for more than 30 years. Members of our management team have collectively personally invested more than $500 million in us since our inception.

- **Stable, long-lived, conventional asset base with low production decline rates.** The majority of our interests are in properties that have produced oil and natural gas for decades. As a result, the geology and reservoir characteristics are well understood, and new development well results are generally predictable, repeatable and present lower risk than unconventional resource plays. Our assets are characterized by long-lived reserves with low production decline rates, a stable development cost structure and low-geologic risk developmental drilling opportunities with predictable production profiles. For example, our base decline rate over the next twelve months is currently estimated to be approximately 8%.

- **Ability to source, integrate and optimize acquisitions.** Our management team has demonstrated the ability to source and integrate acquisitions of various sizes. While at XTO, our management team completed hundreds of acquisitions for over $15 billion in consideration and successfully integrated such acquisitions, ultimately driving significant returns for shareholders. We have successfully drawn on this experience to identify and complete multiple acquisitions to establish our anchor positions in the Permian Basin and San Juan Basin, including our recent 2021 and 2022 acquisitions. We expect that our expertise in sourcing and completing acquisitions will allow us to successfully execute additional bolt-on acquisitions in our existing operating areas and, if and when appropriate, additional opportunistic acquisitions.

- **Conservatively capitalized balance sheet, strong liquidity profile and financial flexibility.** We have a strong and conservative financial position that allows us to effectively allocate capital and grow our reserves and production. Due to the significant existing vertical production and the predictable low-decline profiles associated with our existing production, our business generates significant operating cash flows. We expect to have little to no debt and substantial liquidity, which will provide us with further financial flexibility to fund our capital expenditures and grow production and reserves as part of our existing strategic plan. We may also opportunistically hedge to protect our future operating cash flows from volatility in commodity prices.

Our Properties

As of December 31, 2022, our assets consisted of 848,257 gross (371,727 net) leasehold and mineral acres located primarily in the Permian Basin and San Juan Basin. As of December 31, 2022, our total estimated proved reserves were approximately 143 MMBoe, of which approximately 53% were liquids and approximately 83% were proved developed, both on a Boe basis. In 2022, we produced an average of approximately 23,195 Boe per day, approximately 70% of which came from assets operated by us.

Permian Basin

We acquired our initial 79,970 gross leasehold and mineral acres in the Permian Basin in 2012 and 2013. We subsequently acquired 11,929 additional gross leasehold acres through leasing and multiple bolt-on acquisitions. In November 2021, we acquired producing properties, including 24,052 gross leasehold acres and a CO_2 processing plant in the Permian Basin within New Mexico and CO_2 assets in Colorado (the “Vacuum Properties”) from Chevron Corporation (“Chevron”). In December 2021, we acquired additional producing properties, including 21,112 gross leasehold acres in the Permian Basin within Texas from Chevron (the “Andrews Parker Acquisition”). We refer to these together as the “2021 Acquisitions.” In August 2022 we acquired additional interests in our producing properties and CO_2 gas processing plant in the Permian Basin of New Mexico (the “Additional Interest Vacuum Acquisition”). As of December 31, 2022, we had 49 (gross) active CO_2 injection wells. Production from our CO_2 wells was 17.7 MMcf/d during 2022.

The Permian Basin is one of the oldest and most prolific producing basins in North America. Consisting of approximately 75,000 square miles centered around Midland, Texas, the Permian spans across west Texas and southeast New Mexico. The Permian Basin has been a significant source of oil production in the United States since the 1920s and, according to the EIA, accounted for approximately 46% of all oil production and approximately 18% of all natural gas production in the United States as of December 31, 2022. While horizontal development is the primary focus for many operators, there continues to be significant conventional oil and gas drilling throughout the Permian Basin. Through enhanced oil recovery methods such as CO_2 injection, operators like us are able to unlock incremental additional hydrocarbon production in these older, conventional assets at comparatively lower costs as compared to the drilling and completion costs of horizontal wells.

Our management team believes the development and exploitation of conventional assets in the Permian Basin is among the most economic oil and natural gas plays in the United States. Since completing the 2021 Acquisitions, we have focused our efforts on returning wells to production as well as on other low-risk maintenance projects. As we gain a greater understanding of these recently acquired assets, we expect to increase our drilling and recompletion work. Substantially all of our acreage in the Permian Basin is held by production, which means we do not have to drill any wells to maintain ownership of our leases. We drilled or participated in the drilling of 6 gross wells in the Permian Basin during 2022. Based on current commodity prices, we expect to drill or participate in the drilling of approximately 22 gross wells in 2023. We recompleted 13 gross wells in the Permian Basin in 2022 and expect to recomplete approximately 18 gross wells in 2023. We returned 15 gross wells to production in the Permian Basin in 2022 and expect to return 6 gross wells in 2023. Our base decline rate for our Permian Basin properties over the next 12 months is currently estimated to be approximately 8%.

San Juan Basin

We acquired our initial 175,376 gross leasehold and mineral acres in the San Juan Basin in 2012 and 2013. We subsequently acquired 273,187 additional gross leasehold and mineral acres in June 2020.

The San Juan Basin covers approximately 7,500 square miles in northwestern New Mexico, southwestern Colorado, and parts of Utah and Arizona. Primarily producing natural gas, the San Juan Basin has multiple different formation targets including conventional and unconventional tight sands, coalbed methane and shale. The San Juan is one of the oldest producing basins in the United States, with the first conventional natural gas well drilled in 1921. With the discovery and development of coalbed methane reserves, the San Juan Basin was one of the most prolific natural gas basins in the United States in the 1980s and 1990s. Development activity within the San Juan Basin continued at a significant pace until 2008. With the collapse of commodity prices in 2007, development activity dropped to a very low rate, falling from approximately 40 drilling rigs into 2007 to less than five rigs by 2012. More recently, however, activity within the San Juan Basin has picked up through continued exploration of the unconventional Mancos Shale play. In 2016, the United States Geological Survey ("USGS") estimated that there were 66.3 trillion cubic feet of recoverable natural gas in the Mancos Shale, which is a forty-fold increase from the 1.6 trillion cubic feet of recoverable natural gas estimated by USGS in 2003.

Our San Juan acreage includes substantial, predictable, low-decline natural gas production that provides for relatively stable cash flows. Our base decline rate for our San Juan Basin properties over the next 12 months is currently estimated to be approximately 9%. Our existing production comes from primarily coalbed methane wells. Substantially all of our acreage in the San Juan Basin is held by production. Additionally, as of December 31, 2022, we own 83,836 gross acres in New Mexico in the Mancos Shale. We believe our Mancos Shale properties offer us significant potential upside that is held by production.

We drilled or participated in the drilling of 18 gross wells in the San Juan Basin during 2022. We expect to drill or participate in the drilling of approximately 14 gross wells in 2023 but we will periodically reassess our plans given the volatility in natural gas prices. We recompleted 11 gross wells in the San Juan Basin in 2022 and we expect to recomplete 10 gross wells in 2023. We did not return any wells to production in the San Juan Basin in 2022 and do not expect to return any wells to production in 2023.

For year ended December 31, 2022, our consolidated revenues were derived 48% from oil revenues, 40% from natural gas revenues and 12% from NGL revenues, in each case excluding the unrealized effects of our commodity derivative contracts. After giving effect to unrealized commodity derivative contracts, our revenues were derived 65% from oil revenues, 18% from natural gas revenues and 17% from NGL revenues over the same period. For the year ended December 31, 2022, our total average production was 23,195 Boe/d (approximately 26% oil, 58% natural gas, and 16% NGLs). Over the same period, our average production in the Permian Basin was 7,193 Boe/d (approximately 83% oil, 5% natural gas, and 13% NGLs) and our average production in the San Juan Basin was 14,612 Boe/d (approximately 1% oil, 81% natural gas, and 19% NGLs).

Development Plan and Capital Budget

Historically, our business plan has focused on acquiring and then exploiting producing assets. Funding sources for our acquisitions have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. We incurred $29.8 million of development capital in 2022 and expect to incur approximately $30.0 - $35.0 million for development in 2023. Much of our development time and capital is spent on workovers, recompletions and field optimizations of existing assets. We expect to use the additional information derived from this exploitation to inform our decisions about additional drilling opportunities to pursue, either in recently acquired assets or new acquisitions. To the extent that we complete any acquisitions during 2023, we may reduce our other expected capital plans to offset the acquisition cost and to temper production growth in favor of distributions to our unitholders.

During 2022, we spent approximately $25.6 million to drill 24 gross wells (6.2 net wells) and on related equipment, $3.2 million on recompletions of existing wells and $0.9 million on remedial workovers and other maintenance projects. We spent approximately $18.9 million in the Permian Basin and approximately $10.9 million in the San Juan Basin in 2022.

We expect to allocate a portion of our 2023 budget to projects focused on enhancing existing production. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2023 capital development programs from cash flow from operations. We increased our

2022 capital program to $29.8 million compared to $8.1 million in 2021, primarily in response to the improved oil price environment and the improving global and national economic environment.

Oil, Natural Gas and NGL Data

Reserves

Summary of Oil, Natural Gas and NGL Reserves. The following table presents our estimated net proved oil, natural gas and NGL reserves as of December 31, 2022, 2021 and 2020. The reserve estimates presented in the table below are based on reports prepared by Cawley, Gillespie & Associates, our independent petroleum engineers, which reports were prepared in accordance with current SEC rules and regulations regarding oil and natural gas reserve reporting.

	TXO Energy Partners As of December 31,		
	2022 (1)	**2021 (1)**	**2020 (1)**
Proved Reserves:			
Oil (MBbls)	53,509.2	48,605.6	19,604.8
NGLs (MBbls)	21,932.4	18,027.6	8,311.2
Natural gas (MMcf)	407,877.2	379,275.9	243,172.9
Total Proved Reserves (MBoe)	143,421.1	129,845.9	68,444.8
Standardized Measure (in millions)	$ 1,969.8	$ 986.6	$ 154.4
PV-10 (in millions)(2)	$ 2,005.7	$ 1,022.2	$ 184.6
Proved Developed Reserves:			
Oil (MBbls)	34,672.0	30,207.9	9,787.7
NGLs (MBbls)	20,723.6	17,434.2	8,311.2
Natural gas (MMcf)	385,188.6	353,214.9	218,396.9
Total Proved Developed Reserves (MBoe)	119,593.7	106,511.3	54,498.4
PV-10 (in millions)(2)	$ 1,560.1	$ 772.2	$ 148.4
Proved Undeveloped Reserves:			
Oil (MBbls)	18,837.2	18,397.7	9,817.1
NGLs (MBbls)	1,208.8	593.4	0.0
Natural gas (MMcf)	22,688.6	26,061.0	24,776.0
Total Proved Undeveloped Reserves (MBoe)	23,827.4	23,334.6	13,946.4
PV-10 (in millions)(2)	$ 445.6	$ 250.0	$ 36.2

(1) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $93.67 per barrel for oil and $6.36 per MMBtu for natural gas at December 31, 2022, were $66.56 per barrel for oil and $3.60 per MMBtu for natural gas at December 31, 2021 and were $39.57 per barrel for oil and $1.99 per MMBtu for natural gas at December 31, 2020. The base prices were based upon Henry Hub and WTI-Cushing spot prices, respectively. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these net adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $92.94 per barrel for oil, $29.72 per barrel for NGLs and $4.35 per Mcf for natural gas for the year ended December 31, 2022, $64.76 per barrel for oil, $19.62 per barrel for NGLs and $2.31 per Mcf for natural gas for the year ended December 31, 2021 and $37.77 per barrel for oil, $7.38 per barrel for NGLs and $1.03 per Mcf for natural gas for the year ended December 31, 2020.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Our PV-10 has historically been computed on the same basis as our standardized measure of discounted future net cash flows (“Standardized Measure”), the most comparable measure under GAAP, but does not include a provision for either future well abandonment costs or the Texas gross margin tax. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Additional information regarding our proved reserves and estimated future cash flows therefrom can be found in the notes to our financial statements included in Item 8 and in the reserve reports prepared by Cawley, Gillespie & Associates that are filed as exhibits.

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2022, 2021 and 2020 included in this Annual Report on Form 10-K are based on evaluations prepared by the independent petroleum engineering firm of Cawley, Gillespie & Associates in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering similar resources.

Under SEC rules, proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. If deterministic methods are used, the term “reasonable certainty” implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. If probabilistic methods are used, there should at least be a 90% probability that the quantities actually recovered will equal or exceed the estimate. The technical and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, well-test data, production data (including flow rates), well data (including lateral lengths), historical price and cost information, and property ownership interests. Our independent reserve engineers use this technical data, together with standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy. The proved developed reserves and estimated ultimate recoveries (“EURs”) per well are estimated using performance analysis and volumetric analysis. The estimates of the proved developed reserves and EURs for each developed well are used to estimate the proved undeveloped reserves for each proved undeveloped location (utilizing type curves, statistical analysis, and analogy). All of our proved undeveloped reserves as of December 31, 2022, 2021 and 2020, relate to locations that are one offset away from an existing well.

Internal Controls

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their preparation of reserve estimates. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil, natural gas and NGLs that are ultimately recovered. See “Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry—Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves” for more information. The reserves engineering group is responsible for the internal review of reserve estimates and includes Brandon Hudson, our Manager—Reservoir Engineering. The Reservoir Engineering Manager is primarily responsible for overseeing the preparation of our reserve estimates and has more than 15 years of experience as a reserve engineer. The reserves engineering group is independent of any of our operating areas. The Reservoir Engineering Manager is directly responsible for overseeing the reserves engineering group. The reserves engineering group reviews the estimates with our third-party petroleum consultants, Cawley, Gillespie & Associates, an independent petroleum engineering firm.

Cawley, Gillespie & Associates is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. The lead evaluator that prepared the reserve report was W. Todd Brooker, P.E., President at Cawley Gillespie. Mr. Brooker has been a Petroleum Consultant at Cawley, Gillespie & Associates since 1992 and became President in 2017. He graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering. Mr. Brooker is a State of Texas Licensed Professional Engineer (License #83462) and a member of the Society of Petroleum Evaluation Engineers (SPEE) and the Society of Petroleum Engineers (SPE). Mr. Brooker meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; Mr. Brooker is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2022, our proved undeveloped reserves were composed of 18,837.2 MBbls of oil, 1,208.8 MBbls of NGLs and 22,688.6 MMcf of natural gas for a total of 23,827.4 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs, for the years ended December 31, 2022 and 2021 (in MBoe):

Balance, December 31, 2020	**13,946.4**
Purchases of reserves	9,089.5
Revisions of previous estimates	309.1
Transfers to proved developed	(10.4)
Balance, December 31, 2021	**23,334.6**
Purchases of reserves	1,966.8
Revisions of previous estimates	(990.5)
Transfers to proved developed	(483.5)
Balance, December 31, 2022	**23,827.4**

Revisions of previous estimates of (990.5) MBoe during the year ended December 31, 2022 resulted primarily from forecast changes (1078 MBoe) partially offset by higher commodity prices (87 MBoe). Revisions of previous estimates of 309.1 MBoe during the year ended December 31, 2021 resulted primarily from higher commodity prices (347 MBoe) partially offset by forecast changes (38 MBoe).

We converted 483.5 MBoe of any proved undeveloped reserves into proved developed reserves in 2022. Costs incurred relating to the development of oil and natural gas reserves were $29.8 million during the year ended December 31, 2022. We converted 10.4 MBoe of any proved undeveloped reserves into proved developed reserves in 2021. Costs incurred relating to the development of oil and natural gas reserves were $8.1 million during the year ended December 31, 2021.

We drilled or participated in the drilling of 4 gross wells in the Permian Basin during 2021. We drilled or participated in the drilling of approximately 6 gross wells in the Permian Basin during 2022, and we expect to drill or participate in the drilling of approximately 22 gross wells in the Permian Basin during 2023. In addition, we participated in the drilling of 6 gross wells in the San Juan Basin during 2021. We drilled or participated in the drilling of approximately 18 gross wells in the San Juan Basin during 2022, and we expect to drill or participate in the drilling of approximately 14 gross wells in the San Juan Basin during 2023.

All of our PUD drilling locations are scheduled to be drilled within five years of December 31, 2022. We drilled and completed or participated in the drilling and completion of 4 PUD locations during 2022. We anticipate drilling and completing or participating in the drilling and completion of approximately 23 PUD locations during 2023, 35 during 2024, 63 during 2025, 46 during 2026 and 55 during 2027. These PUD locations relate to 23.8 MMBoe of PUD reserves. Our development costs relating to the development of our PUDs at December 31, 2022 are projected to be $24.2 million in 2023, $31.4 million in 2024, $32.3 million in 2025, $33.1 million in 2026 and $33.6 million in 2027 for a total of $154.6 million of future development costs. All of these PUD drilling locations are part of a development plan adopted by management. We expect that the cash flow generated by our existing wells, in addition to availability under our Credit Agreement, will be sufficient to fund our drilling program, maintenance capital expenditures and PUD conversion into proved developed reserves in accordance with our development schedule. Please see “Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry—Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.”

Natural Gas, Oil and NGL Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding our production and operating data for the periods indicated.

Production data:

Sales:

	Year Ended December 31,		
	2022	**2021**	**2020**
Permian Basin			
Natural gas sales (MMcf)	728	507	635
Natural gas liquids sales (MBbl)	334	81	77
Oil and condensate sales (MBbl)	2,170	985	897
Total (MBoe)	2,626	1,151	1,080
Total (MBoe per day)	7	3	3
San Juan			
Natural gas sales (MMcf)	25,886	26,795	18,415
Natural gas liquids sales (MBbl)	991	995	772
Oil and condensate sales (MBbl)	28	35	34
Total (MBoe)	5,333	5,495	3,875
Total (MBoe per day)	15	15	11
Other			
Natural gas sales (MMcf)	2,943	3,287	3,081
Natural gas liquids sales (MBbl)	9	13	11
Oil and condensate sales (MBbl)	8	13	9
Total (MBoe)	507	574	534
Total (MBoe per day)	1	2	1
Total (MBoe)	8,466	7,220	5,489

Average realized sales prices:

	Year Ended December 31,		
	2022	2021	2020
Permian Basin			
Natural gas excluding effects of derivatives (per Mcf)	$ 5.36	$ 3.94	$ 1.27
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 47.85	$ 32.50	$ 12.62
Oil and condensate excluding effects of derivatives (per Bbl)	$ 93.94	$ 67.93	$ 37.30
San Juan			
Natural gas excluding effects of derivatives (per Mcf)	$ 6.65	$ 4.03	$ 1.90
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 31.32	$ 24.59	$ 9.78
Oil and condensate excluding effects of derivatives (per Bbl)	$ 76.30	$ 55.73	$ 31.69
Other			
Natural gas excluding effects of derivatives (per Mcf)	$ 6.69	$ 3.76	$ 2.01
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 32.46	$ 23.39	$ 12.01
Oil and condensate excluding effects of derivatives (per Bbl)	$ 88.55	$ 59.30	$ 38.75
($ / Boe)	$ 53.11	$ 30.38	$ 15.57

Expense per Boe:

	Year Ended December 31,		
	2022	2021	2020
Permian Basin			
Production	$ 34.21	$ 30.67	$ 25.23
Taxes, transportation, and other	$ 10.67	$ 6.90	$ 3.95
Depreciation, depletion, and amortization	$ 11.96	$ 19.77	$ 25.20
San Juan			
Production	$ 6.39	$ 5.62	$ 4.82
Taxes, transportation, and other	$ 12.13	$ 8.66	$ 5.40
Depreciation, depletion, and amortization	$ 1.20	$ 2.03	$ 1.97
Other			
Production	$ 7.39	$ 5.39	$ 6.02
Taxes, transportation, and other	$ 4.52	$ 4.33	$ 4.31
Depreciation, depletion, and amortization	$ 7.06	$ 10.42	$ 14.02

Productive Wells

As of December 31, 2022, we owned interests in the following number of productive wells:

	Oil Wells	Gas Wells	Total
Permian Basin			
Gross	3,765.0	118.0	3,883.0
Net	671.1	11.2	682.3
San Juan			
Gross	36.0	11,429.0	11,465.0
Net	0.1	1,094.0	1,094.1
Other			
Gross	727.0	2,194.0	2,921.0
Net	—	86.7	86.7
Total			
Gross	4,528.0	13,741.0	18,269.0
Net	671.2	1,191.9	1,863.1

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2022 relating to our developed and undeveloped acreage. Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	141,236	76,988	160	80	141,396	77,068
San Juan Basin	445,591	245,692	982	717	446,573	246,409
Other	260,288	48,250	—	—	260,288	48,250
Total	847,115	370,930	1,142	797	848,257	371,727

Drilling Results

The following table sets forth the results of our drilling activity for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	Years Ended December 31,					
	2022 (1)		2021 (2)		2020 (3)	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Completed as:						
Gas wells	10	4.1	4	0.9	—	—
Oil wells	14	2.1	6	0.6	4	0.3
Non-productive	—	—	—	—	—	—
Total	24	6.2	10	1.5	4	0.3
Exploratory wells:						
Completed as:						
Gas wells	—	—	—	—	—	—
Oil wells	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—
Total	—	—	—	—	—	—
Total	**24**	**6.2**	**10**	**1.5**	**4**	**0.3**

(1) These 24 wells do not include any gross wells drilled by other operators during the year ended December 31, 2022 in which we elected not to participate.
(2) These 10 wells include two gross (0.0 net) wells drilled by other operators during the year ended December 31, 2021 in which we elected not to participate.
(3) These 4 wells include two gross (0.0 net) wells drilled by other operators during the year ended December 31, 2020 in which we elected not to participate.

The following table sets forth information regarding our drilling activities as of December 31, 2022 and December 31, 2021, including with respect to wells awaiting completion, undergoing completion activities and which we have begun drilling subsequent to December 31, 2022.

December 31, 2022	Permian Basin		San Juan Basin	
	Gross	Net	Gross	Net
Drilling	—	—	3	0.5
Awaiting completion	5	2.5	4	0.5
Undergoing completion activities	—	—	—	—
Drilling begun subsequent to December 31, 2022	7	0.1	—	—

December 31, 2021	Permian Basin		San Juan Basin	
	Gross	Net	Gross	Net
Drilling	—	—	—	—
Awaiting completion	4	1.3	—	—
Undergoing completion activities	—	—	—	—

Operations

General

We operated wells responsible for approximately 70% of our production for the year ended December 31, 2022 and 68% for the year ended December 31, 2021. As operator, we design and manage the development, recompletion or workover for all of the wells we operate and supervise operation and maintenance activities on a day-to-day basis. We do not own the drilling rigs or other oil field services equipment used for drilling or maintenance on the properties we operate.

Independent contractors engaged by us provide a portion of the equipment and personnel associated with these activities. We currently engage independent contractors who are engineers and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Virtually all of our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies. Maverick Natural Resources Corporation, Occidental Petroleum Corporation and Jo Mill Oil Company are the operators on more than 50% of our non-operated acreage in the Permian Basin.

Our assets include a 50% interest in Cross Timbers Energy, LLC ("Cross Timbers"). Certain affiliates of Exxon and XTO, which we refer to collectively as the "XTO Entities," collectively own the remaining 50% interest in Cross Timbers. We account for our undivided interest in our investment in Cross Timbers using the proportionate consolidation method, pursuant to which we consolidate our proportionate share of assets (including reserves), liabilities, revenues and expenses of the joint venture. For the year ended December 31, 2022, Cross Timbers represents approximately 28% of our revenues excluding the effects of our commodity derivative contracts and approximately 33% of our proved reserves, on a proportional ownership basis, with assets primarily located in the Permian Basin of Texas and New Mexico and the San Juan Basin of New Mexico and Colorado.

In accordance with the limited liability company agreement governing Cross Timbers, or the "JV LLCA," Cross Timbers is managed by us and governed by a member management committee comprised of six members, three of whom are appointed by us and three of whom are appointed by the XTO Entities. The JV LLCA requires that certain matters, including certain material contracts or acquisitions, mergers, sale of substantially all assets or other change of control transactions, and transfers of our interest to a third party, be approved by unanimous consent of the voting members of the management committee and therefore require the approval of the XTO Entities. While Cross Timbers is required to distribute all net cash flow to the members pro rata in accordance with their respective membership interests on a quarterly basis pursuant to the JV LLCA, we do not have sole control of the amount of distributions to be made by Cross Timbers.

Cross Timbers is also a party to an operating and services agreement with us pursuant to which we provide all administrative services and conduct operations that are necessary or proper for the development, operation, protection and maintenance of the assets held by Cross Timbers in exchange for a management fee. We earned management fees from Cross Timbers of $5.9 million for year ended December 31, 2022 and $6.1 million for the year ended December 31, 2021.

Marketing and Customers

We market the majority of the natural gas, NGL, crude oil and condensate production from the properties on which we operate. We also market products produced by third party working interest owners who participate in various wells or production units on which we operate. We proportionately pay our royalty owners from the sales attributable to our working interest. Production from our properties is marketed using methods that are consistent with industry practice. Purchasers of our production are selected on the basis of price, credit quality and service reliability. Sales prices are negotiated based on factors normally considered in the industry, such as index or spot price, differentials based on the distance from tailgate of processing plants to end users, commodity quality and prevailing supply and demand conditions. Market volatility due to fluctuating weather conditions, international political developments, overall energy supply and demand, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We sell the majority of our production under arm's length contracts with terms of 12 months or less, including on a month-to-month basis, to a relatively small number of customers, as is customary in our industry. We generally sell natural gas, NGL, crude oil and condensate production through production sale agreements with customary terms and conditions for the oil and natural gas industry at prevailing market prices, adjusted for quality, transportation fees, fractionation fees, regional price differentials, and, in the case of natural gas, energy content. Typically, our sales contracts are based on pricing provisions that are tied to a market index or postings. None of our contracts have minimum volume commitments. We have no commitments beyond twelve months to deliver a fixed or determinable quantity of our oil or natural gas production under our existing contracts. However, our existing contracts for NGL production include commitments for an average of 17 months.

Additionally, we market our excess CO_2 production that we do not use for our enhanced oil recovery operations in the Permian Basin. This excess CO_2 is sold through a combination of an arm's length contract to an external counterparty and by participating in another CO_2 production working interest owner's sales under the terms of a unit agreement. The price we receive for this CO_2 is tied to oil prices as is customary in the industry. We have a contract that goes beyond twelve months for our excess CO_2 production.

For the year ended December 31, 2022, Chevron USA and Phillips 66 Company accounted for more than 35% of our total revenues, excluding the impact of our commodity derivatives. For the year ended December 31, 2021, Phillips 66 Company, Tenaska Marketing and Eco-Energy, Inc. accounted for more than 40% of our total revenues, excluding the impact of our commodity derivatives. No other purchaser accounted for more than 10% of our total revenue during such period. We generally do not have long-term contracts with our customers but rather we sell the substantial majority of our production under arm's length contracts with terms of 12 months or less, including on a combined basis, to a relatively small number of customers. The loss of any such purchaser could materially adversely affect our financial condition, results of operations and ability to make distributions to our unitholders. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any such purchaser would not have a material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers. For more details, see "Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry—We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce."

Hedging

Our policy is to hedge opportunistically a portion of our production at commodity prices management deems attractive to mitigate our exposure to lower commodity prices. Under our Credit Facility, we are required to hedge at least 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022, and at least 50% for the period from month 13 to month 30. However, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and liquidity under the Credit Facility is equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month twenty-four will be reduced to 50% and the requirement to maintain the minimum required hedge volume for months 25 through 30 shall be removed. Our Credit Facility prohibits us from hedging more than 90% of our reasonably projected production for any fiscal year. From September 30, 2022 through the next scheduled spring redetermination which shall occur no later than June 30, 2023, we received waivers to reduce the hedging requirement from 30 months to 15 months and from 50% to 45% of the reasonably anticipated projected production. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement" for more information. While there is a risk that we may not be able to realize the benefits of rising prices, we enter into hedging agreements because of the benefits of predictable, stable cash flows.

We enter futures contracts, energy swaps, options and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We also enter costless price collars, which set a ceiling and floor price to hedge our exposure to price fluctuations on natural gas sales. When actual commodity prices exceed the ceiling price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the floor price, we receive this difference from the counterparty. If the actual commodity price falls in between the ceiling and floor price, there is no cash settlement. For more details, see "Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry—We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk."

For a more detailed discussion of our hedging activities, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosure About Market Risk."

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in producing oil and natural gas properties, particularly during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

There is also competition between oil and natural gas producers and other industries producing energy and fuel and alternative technologies to reduce energy and fuel consumption. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the state and local jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Oil and Natural Gas Leases

The typical oil lease agreement covering our properties provides for the payment of royalties to the mineral owner for all hydrocarbons produced from any well drilled on the lease premises. The lessor royalties and other leasehold burdens on our properties range from less than 12.5% to 57.5%, resulting in a net revenue interest to us of 87.0% on average, on a 100% working interest basis. Based on the Standardized Measure, our value-weighted average net revenue interest on our properties was approximately 86.0%, on a 100% working interest basis, based on our December 31, 2022 reserve report. Substantially all of our leases are held by production and do not require continuous development.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct a cursory review of the title to the properties in connection with the acquisition of producing wells and/or additional acreage. Typically, that examination is limited to the seller’s interest. At such time as we determine to conduct drilling operations, we administer a thorough title examination and perform curative work with respect to significant defects in title, prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects and/or other curative matters relative to those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title reports on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant leases and, depending on the materiality of properties, we will review previously obtained title opinions, update title, and in some cases have new title opinions rendered by a licensed oil and gas attorney. Our oil and natural gas properties are subject to customary royalty and perhaps other interests, possible liens for current taxes and potentially other encumbrances which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we hold satisfactory title to all of our material assets. Although title to these properties is subject to certain encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights of way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report on Form 10-K.

Seasonality

Generally, but not always, the demand for oil and natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers also may impact this demand. In addition, pipelines, utilities, local distribution companies and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also impact the seasonality of demand. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

In addition, our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes or lightning storms, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. See “Risk Factors—Risks Related to the Oil, Natural Gas and NGL Industry and Our Business—Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate.”

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs have not had a material adverse effect on our results of operations; however, we are unable to predict the future costs or impact considered by Congress, the states, the FERC and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation Affecting Production

The production of oil and natural gas is subject to United States federal and state laws and regulations, and orders of regulatory bodies under those laws and regulations, governing a wide variety of matters. All of the jurisdictions in which we own or operate producing properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the amount of oil and natural gas we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGLs and natural gas within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or limit the number of locations we can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation Affecting Sales and Transportation of Commodities

Sales prices of oil, natural gas, condensate and NGLs are not currently regulated and are made at market prices. Although prices of these energy commodities are currently unregulated, the United States Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil, natural gas, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state and federal reporting requirements.

The price and terms of service of transportation of the commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of natural gas produced by us, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for natural gas production, if any, of the drilling program and the cost of such capacity. Further state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to ensure terms and conditions of interstate transportation service are not unduly discriminatory or unduly preferential, to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

In addition to the regulation of natural gas pipeline transportation, FERC has jurisdiction over the purchase or sale of natural gas or the purchase or sale of transportation services subject to FERC's jurisdiction pursuant to the EPAct 2005. Under the EPAct 2005, it is unlawful for "any entity," including producers such as us, that are otherwise not subject to FERC's jurisdiction under the NGA to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives FERC authority to impose civil penalties for violations of the NGA and the Natural Gas Policy Act of 1978 up to $1,496,035 per violation per day. The anti-manipulation rule applies to activities of otherwise non jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under FERC Order No. 704 (defined below).

In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order No. 704"). Under Order No. 704, any market participant, including a producer that engages in certain wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to the formation of price indices. Not all types of natural gas sales are required to be reported on Form No. 552. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 is intended to increase the transparency of the wholesale natural gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

Through several issuances, FERC has signaled its intention of undertaking a "rigorous review" of reasonably foreseeable greenhouse gas ("GHG") emissions of new or expanded natural gas transportation facilities and their contribution to climate change, along with the enhanced consideration of other factors such as project need, landowner impacts and environmental justice, in determining the benefits of a project and the significance of its environmental impacts. FERC considers project benefits and environmental impacts in determining whether to issue a certificate to construct a new project under the Natural Gas Act and in its environmental analysis required under the National Environmental Policy Act. On March 24, 2022, FERC announced that it was seeking comments on these draft proposed policies, which initially had been issued as guidance. If adopted, these policy changes may create delays in, and potentially affect the outcomes of, FERC's future assessments of the need for and environmental impacts of gas pipeline projects in determining whether a project is required by the present or future public convenience or necessity under the Natural Gas Act, which in turn may reduce the development of interstate natural gas pipeline projects and the future availability of pipeline capacity to transport our natural gas production.

The FERC also regulates rates and terms and conditions of service on interstate transportation of liquids, including NGLs, under the Interstate Commerce Act, as it existed on October 1, 1977 ("ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that certain interstate liquids pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

The rates charged by many interstate liquids pipelines are currently adjusted pursuant to an annual indexing methodology established and regulated by FERC, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning July 1, 2021, FERC established an annual index adjustment equal to the change in the producer price index for finished goods minus 0.21%. This adjustment is subject to review every five years. Under FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by obtaining market based rate authority (demonstrating the pipeline lacks market power), establishing rates by settlement with all existing shippers, or through a cost of service approach (if the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology). Increases in liquids transportation rates may result in lower revenue and cash flows for us.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity or for new shippers. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to liquids pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

On February 17, 2022, FERC issued a Notice of Inquiry, seeking to explore oil pipeline capacity allocation issues that arise when anomalous conditions affect the demand for oil pipeline capacity and what actions FERC should consider to address those allocation issues. This proceeding was initiated in part by the impact of the COVID-19 pandemic on jet fuel shippers' ability to access capacity on oil pipelines using historic-based prorationing. However, the Notice of Inquiry sought comments on the broader issue of diminished access to oil pipeline capacity during anomalous conditions. Rates for intrastate pipeline transportation of liquids are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly situated competitors.

In addition to FERC's regulations, we are required to observe anti market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately $1,426,319 per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the CFTC to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of approximately $1,404,520 or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and the protection of the environment and natural resources (including threatened and endangered species and their habitat). Numerous governmental entities, including the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions.

These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and on-going operations, such as requirements to close pits and plug abandoned wells; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities, or waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. The cost of continued compliance with existing requirements is not expected to materially affect us. However, there is no assurance that compliance costs will remain the same in the future for such existing or any new laws and regulations or that costs related to such future compliance will not have a material adverse effect on our business and operating results.

In addition, governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political and regulatory risks in the United States, including climate change related pledges made by certain elected public officials. President Biden has issued several executive orders focused on addressing climate change since taking office, including items that may impact the costs to produce, or demand for, oil and natural gas. Additionally, in November 2021, the Biden Administration released “The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050,” which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-carbon dioxide GHG emissions, such as methane and nitrous oxide. The Biden Administration is also considering revisions to the leasing and permitting programs for oil and natural gas development on federal lands.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws, as amended from time to time, to which our business operations are or may be subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Wastes

The Resource Conservation and Recovery Act (“RCRA”), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the U.S. Environmental Protection Agency (“EPA”), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of natural gas, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA’s less stringent non-hazardous waste provisions, state laws or other federal laws. However, it is possible that certain natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our, as well as the oil and natural gas exploration and production industry’s costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. In the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes under RCRA.

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed of or arranged for the transportation or disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA.

We currently own, lease, or operate numerous properties that have been used for oil, natural gas and NGL exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including offsite locations, where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons were not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In 2015, the EPA and the U.S. Army Corps of Engineers ("Corps") issued a final rule attempting to clarify the federal jurisdictional reach over waters of the United States ("WOTUS"). The rule has the potential to expand CWA jurisdiction to ephemeral waters found in generally arid regions of the United States. In January 2020, the EPA and Corps replaced the WOTUS rule with the narrower Navigable Waters Protection Rule, and litigation ensued. In August 2021, a federal judge struck down the Navigable Waters Protection Rule. Soon after, the Biden administration and the Corps announced that they have stopped enforcing the Navigable Waters Protection Rule nationwide and that they are reverting back to the 1986 WOTUS definition. In January 2023, the EPA and Corps issued a final rule to revise the definition of "waters of the United States" to put back into place the pre-2015 definition, updated to reflect consideration of Supreme Court decisions, including the Supreme Court's April 2020 decision holding that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. In October 2022, the Supreme Court heard oral arguments for a case regarding the jurisdictional reach of WOTUS, and is expected to issue its decision in 2023. In addition to the case before the Supreme Court, multiple states and industry groups have challenged the rule in federal district court. In March 2023, a federal district court judge in the Southern District of Texas issued a ruling pausing implementation of the final rule in Texas and Idaho, while declining to pause the rule nationwide, until the Supreme Court publishes its decision. Future implementation of the WOTUS rule therefore remains uncertain at this time. Depending on the outcome of the pending court cases related to the federal jurisdictional reach over WOTUS, we could be subject to additional permitting obligations, which could lead to potential project delays and additional compliance costs.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Subsurface Injections

In the course of our operations, we produce water in addition to oil, natural gas and NGLs. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near below ground disposal wells used for the injection of natural gas related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. In response to these concerns, regulators in some states have adopted, and other states are considering adopting, additional requirements related to seismic safety. These seismic events have also led to an increase in tort lawsuits filed against exploration and production companies as well as the owners of underground injection wells. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability; however, these costs are commonly incurred by all oil and natural gas producers and we do not believe that the costs associated with the disposal of produced water will have a material adverse effect on our operations.

Air Emissions

The Clean Air Act ("CAA") and comparable state laws restrict the emission of air pollutants from many sources, such as, tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Recently, there has been increased regulation with respect to air emissions resulting from the oil and natural gas sector. For example, the EPA promulgated rules in 2012 under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and a separate set of requirements to address certain hazardous air pollutants frequently associated with oil and natural gas production and processing activities pursuant to the National Standards for Emission of Hazardous Air Pollutants program. With regard to production activities, these final rules require, among other things, the reduction of volatile organic compound ("VOC") emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further requires that a subset of these selected wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels.

The EPA has also imposed increasingly stringent performance standards on oil and gas operations. In 2016, the EPA issued regulations under NSPS OOOOa that require operators to reduce methane and VOC emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector. The proposed rule would establish standards of performance for sources that commence construction, modification or reconstruction after the date the proposed rule was published in the Federal Register and would establish emissions guidelines, which will inform state plans to establish standards for existing sources. The EPA issued a supplemental proposed rule in November 2022 to update, strengthen and expand its November 2021 proposed rule. The supplemental proposed rule would impose more stringent requirements on the natural gas and oil industry, and is expected to be finalized in 2023. State agencies have similarly imposed increasing restrictions on emissions from oil and gas operations. For example, in 2022, the New Mexico Environment Department adopted new regulations establishing emission reduction requirements for storage vessels, compressors, turbines, heaters, engines, dehydrators, pneumatic devices, produced water management units, and other equipment and processes. Increasingly stringent requirements on new oil and gas facilities, or the application of new requirements to existing facilities, could result in additional restrictions on operations and increased compliance costs, which could be significant.

The Bureau of Land Management (the "BLM") also finalized rules (the "BLM methane rule") in November 2016 that seek to limit methane emissions from exploration and production activities on federal lands by imposing limitations on venting and flaring of natural gas, as well as requirements for the implementation of leak detection and repair programs for certain processes and equipment. After attempts by the Trump administration to delay implementation of the BLM methane rule, and legal challenges both to the BLM methane rule and the delays, the BLM issued a final rule in September 2018 rescinding many of the provisions of the 2016 BLM methane rule, including the requirement to implement leak detection and repair programs, and imposing certain new requirements in a manner the BLM considered would reduce unnecessary compliance obligations on the industry. In July 2020 a federal district court in California vacated the 2018 rescission rule. BLM filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit; however, the federal district court in California entered a final judgment vacating the September 2018 rescission rule in October 2020. Separately, in October 2020, a federal district court judge in Wyoming vacated the 2016 rule. Environmental groups appealed the Wyoming decision in December 2020, and litigation is ongoing. In November 2022, the BLM issued a new proposed rule to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on federal and American Indian leases.

The EPA also finalized separate rules under the CAA in June 2016 regarding criteria for aggregating multiple sites into a single source for air quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities (such as tank batteries and compressor stations), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In addition, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground level ozone from the current standard of 75 ppb for the current 8 hour primary and secondary ozone standards to 70 ppb for both standards, and completed attainment/non-attainment designations in July 2018. EPA reviewed the 2015 standards in 2020, but retained the standard without revision. Impacts associated with the 2015 standard vary by geographic location, but could include additional fees and more stringent permitting requirements, among other things. None of the counties in which we operate have been designated as non-attainment. However, in 2017, the EPA designated certain counties in southeastern New Mexico and West Texas located in the Permian Basin attainment/unclassifiable for the 2015 ozone NAAQS. In June 2022, EPA announced that it is considering a discretionary redesignation for these counties based on current monitoring data and other air quality factors. If the Permian Basin counties in which we operate were redesignated as nonattainment areas, this could subject us to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements and increased permitting delays and costs.

Compliance with one or more of these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. In addition, our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and criminal enforcement actions.

Regulation of GHG Emissions (Climate Change)

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by state agencies. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified large, GHG emission sources in the United States, including certain onshore and offshore oil and natural gas production sources, which include certain of our operations. As discussed above, federal regulatory action with respect to GHG emissions from the oil and natural gas sector has focused on methane emissions; however, implementation of the federal methane rules is uncertain at this time.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, the Inflation Reduction Act, recently passed by Congress and signed into law by President Biden in 2022, imposes several new climate-related requirements on oil and gas operators, including a first-ever fee on GHG emissions from certain facilities through a fee for leaks or venting of methane, starting at $900 per ton in 2024 and rising to $1,500 per ton in and after 2026. The act also appropriates significant federal funding for renewable energy initiatives. These developments may make it harder for the oil and gas industry to attract capital. Additionally, the current administration has highlighted addressing climate change as a priority and has issued several executive orders addressing climate change, including one that calls for substantial action, such as the increased use of zero-emission vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across government agencies and economic sectors. Additionally, the SEC issued a proposed rule in March 2022 that would mandate extensive disclosure of climate-related data, risks, and opportunities, including financial impacts, physical and transition risks, related governance and strategy, and GHG emissions, for certain public companies. In the absence of comprehensive federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. Although the United States had withdrawn from the Paris Agreement, President Biden has recommitted the United States and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below

2005 levels by 2030. In November 2021, the international community gathered again in Glasgow at the COP26, during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs. Relatedly, the United States and European Union jointly announced the launch of the “Global Methane Pledge,” which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including “all feasible reductions” in the energy sector. While there were limited announcements at COP27, which took place in November 2022 in Sharm-El Sheik, with respect to the reduction of fossil fuel use, there were negotiations on emissions reduction targets and reduction of fossil fuel use amongst the international community, and it is likely that these discussions will continue at COP28.

Although it is not possible at this time to predict how new laws or regulations in the United States that may be adopted or issued to address GHG emissions would impact our business, any such future laws, regulations or legal requirements imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. New laws or regulations may also negatively impact our competitive advantage; for example, as discussed above, the Inflation Reduction Act of 2022 includes a variety of tax credits to incentivize the development and use of solar, wind, and other alternative energy sources while imposing several new requirements on oil and gas operators. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time in multiple, though not all, potential scenarios. In addition, increasing public attention on environmental, social, and governance (“ESG”) matters and climate change has resulted in demands for action related to climate change and energy transition matters, such as promoting the use of substitutes to fossil fuel products, encouraging the divestment of fossil fuel equities, and pressuring lenders and other financial services companies to limit or curtail activities with fossil fuel companies. Initiatives to incentivize a shift away from fossil fuels could reduce demand for hydrocarbons, thereby reducing demand for our services and causing a material adverse effect on our earnings, cash flows and financial condition.

Litigation risks are also increasing as a number of entities have sought to bring suit against various oil and natural gas companies in state or federal court, alleging among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts.

Finally, it should be noted that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. We engage in hydraulic fracturing as part of our operations currently and may continue to do so in the future.

Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published in June 2016 an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under certain limited circumstances.” To date, the EPA has taken no further action in response to the December 2016 report. Also, the BLM finalized rules in March 2015, establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands. This rule was struck down by a Wyoming federal district court judge in June 2016 but was subsequently appealed by the BLM to the U.S. Circuit Court of Appeals for the Tenth Circuit. In September 2017, the Tenth Circuit issued a ruling to vacate this decision and dismiss the lawsuit challenging the rule in light of the BLM's proposed rulemaking. In December 2017, BLM issued a final rule repealing the 2015 hydraulic fracturing rule. The BLM's rescission of the rule was challenged by several environmental groups and states in the United States District Court for the Northern District of California. The United States District Court for the Northern District of California upheld the BLM's rescission in a March 2020 decision.

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Meanwhile, the regulation of hydraulic fracturing has continued at the state level. In the event that a new, federal or state level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Activities on Federal Lands

Oil and gas exploration, development and production activities on federal lands, including American Indian lands, are administered by the BLM. Operations on federal and tribal lands are frequently subject to permitting delays. Operations on these lands are also subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. We currently have exploration, development and production activities on federal lands and our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial.

Moreover, the Biden administration's January 2021 climate change executive order directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands and in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices. In November 2021, the U.S. Department of the Interior released its "Report On The Federal Oil And Gas Leasing Program," which assessed the current state of oil and gas leasing on federal lands and proposed several reforms, including raising royalty rates and implementing stricter standards for entities seeking to purchase oil and gas leases. In January 2022, a federal district court judge in Washington, D.C. vacated the results of the federal government's Lease Sale 257, effectively canceling the sale, on the grounds that the federal government failed to consider foreign consumption of oil and natural gas from its GHG emissions analysis. However, in compliance with the Inflation Reduction Act of 2022, the Bureau of Ocean Energy Management ("BOEM") reinstated Lease Sale 257 in September 2022. In February 2022, a federal district court judge in Louisiana blocked the Biden Administration's method of calculating the social costs associated with GHGs, and specifically blocked federal agencies from considering the findings from the White House Interagency Working Group, which had been tasked with devising new metrics based on the Obama-era calculations. In response, also in February 2022, the Biden administration asked the court to stay the injunction, and announced that it would be suspending or delaying new federal oil and gas leases. The Biden administration resumed its federal leasing program in April 2022. These recent developments and the Biden administration's and certain federal courts' focus on the climate change impacts of federal projects could result in significant changes to the federal oil and gas leasing program in the future. Restrictions surrounding onshore drilling, onshore federal lease availability, and restrictions on the ability to obtain required permits, could have a material adverse impact on our operators and, in turn, our operations.

Endangered Species and Migratory Birds Considerations

The federal Endangered Species Act ("ESA"), and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migrating birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of a 2011 settlement agreement, the U.S. Fish and Wildlife Service ("FWS") was required to make a determination on listing numerous species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The FWS did not meet that deadline, but continues to review species for listing under the ESA. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. For example, the FWS issued a final rule in November 2022 listing two Distinct Population Segments ("DPS") of the Lesser Prairie-

Chicken. The listing, which came into effect on January 24, 2023, lists the Southern DPS of the Lesser Prairie-Chicken as endangered, and the Northern DPS as threatened.

Similarly, if we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases. In August 2019, the FWS and the National Marine Fisheries Service issued three rules amending the implementation of the ESA regulations, among other things revising the process for listing species and designating critical habitat. Two more rules were finalized in 2020, which narrowed the definition of habitat and revised the criteria for designating and excluding critical habitat. A coalition of states and environmental groups has challenged the three 2019 rules. In November 2022, the U.S. District Court for the Northern District of California remanded (without vacatur) the 2019 rules to FWS for further review, with potential changes to the remanded rules planned for 2023. The 2020 rules were rescinded in the summer of 2022. In addition, the federal government has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. In December 2017, the Department of Interior issued a new opinion revoking its prior enforcement policy and concluded that an incidental take is not a violation of the Migratory Bird Treaty Act. In August 2020, a federal district court struck down the December 2017 opinion, and the Department of the Interior responded by issuing a new rule in January 2021 that reduced the activities that could incur liability under the MBTA. The Biden administration has since revoked the January 2021 rule; published an Advanced Notice of Proposed Rulemaking announcing an intent to solicit comments to help develop proposed regulations establishing a permitting system to authorize, under certain circumstances, the incidental take of migratory birds; and issued a Director’s Order “establishing criteria for the types of conduct that will be a priority for enforcement activities with respect to incidental take of migratory birds.”

OSHA

We are subject to the requirements of the OSHA and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right to Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other natural gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. There can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations.

Human Capital Resources

As of December 31, 2022, we had 191 total employees, 180 of which were full-time employees. From time to time we utilize the services of independent contractors to perform various field and other services. We are not a party to any collective bargaining agreements, and have not experienced any strikes or work stoppages. In general, we believe that employee relations are satisfactory.

We are focused on attracting, engaging, developing, retaining and rewarding top talent. We strive to enhance the economic and social well-being of our employees and the communities in which we operate. We are committed to providing a welcoming, inclusive environment for our workforce, with best-in-class training and career development opportunities to enable employees to thrive and achieve their career goals. The health, safety, and well-being of our employees is of the utmost importance.

In response to COVID-19, we adopted enhanced safety measures and practices to protect employee health and safety and minimize the risk of business disruption.

Available Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and related amendments, exhibits and other information with the Securities and Exchange Commission, or the SEC. You may access and read our filings without charge through the SEC's website at www.sec.gov or through our website at www.txoenergy.com, as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Information contained on, or accessible through, our website shall not be deemed incorporated into and is not a part of this Annual Report on Form 10-K.

Item 1A. Risk Factors

Our business involves a high degree of risk. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. Additionally, new risks may emerge at any time and we cannot predict those risks or estimate the extent to which they may affect financial performance.

If any of the following risks actually occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and our unitholders could lose all or part of their investment.

Risks Related to Cash Distributions

We may not have sufficient available cash to pay any quarterly distribution on our common units following the establishment of cash reserves and payment of expenses.

We may not have sufficient available cash each quarter to pay distributions on our common units. Under the terms of our partnership agreement, the amount of cash available for distribution will be reduced by our operating expenses and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including development, optimization and exploitation of our oil and natural gas properties, future debt service requirements and future cash distributions to our unitholders. The amount of available cash that we distribute to our unitholders will depend principally on the cash we generate from operations, which will depend on, among other factors:

- the amount of oil, natural gas and NGLs we produce;
- the prices at which we sell our oil, natural gas and NGL production;
- the amount and timing of settlements on our commodity derivative contracts;
- the level of our capital expenditures, including scheduled and unexpected maintenance expenditures;
- the level of our operating costs, including payments to our general partner and its affiliates for general and administrative expenses; and
- the level of our interest expenses, which will depend on the amount of our outstanding indebtedness and the applicable interest rate.

Furthermore, the amount of cash we have available for distribution depends primarily on our cash flow, including cash from financial reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net income for financial accounting purposes.

The amount of our quarterly cash distributions from our available cash, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. We do not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Our future business performance may be volatile, and our cash flows may be unstable. We do not have a minimum quarterly distribution. Because our quarterly distributions will significantly correlate to the cash we generate each quarter after payment of our fixed and variable expenses, future quarterly distributions paid to our unitholders will vary significantly from quarter to quarter and may be zero. Please read “Cash Distribution Policy.”

Risks Related to Our Business and the Oil, Natural Gas and NGL Industry

The volatility of oil, natural gas and NGL prices due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.

Our revenues, operating results, cash available for distribution and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil, natural gas and NGLs. Prices for oil, natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors beyond our control. These factors include, but are not limited to:

- worldwide and regional economic conditions impacting the supply and demand for oil, natural gas and NGLs;
- the level of global oil and natural gas exploration and production;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the armed conflict in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- the ability of and actions taken by members of Organization of the Petroleum Exporting Countries (“OPEC”) and other oil-producing nations in connection with their arrangements to maintain oil prices and production controls;
- the impact on worldwide economic activity of an epidemic, outbreak or other public health events, such as COVID-19;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals;
- weather conditions across the globe;
- technological advances affecting energy consumption and energy supply;
- speculative trading in commodity markets, including expectations about future commodity prices;
- the proximity of our natural gas, NGL and oil production to, and capacity, availability and cost of, natural gas pipelines and other transportation and storage facilities, and other factors that result in differentials to benchmark prices;
- the impact of energy conservation efforts;
- the price and availability of alternative fuels;
- stockholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas to minimize the emission of greenhouse gases;

- domestic, local and foreign governmental regulation and taxes; and

- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements accurately. Changes in oil, natural gas and NGL prices have a significant impact on the amount of oil, natural gas and NGL that we can produce economically, the value of our reserves and on our cash flows. Historically, oil, natural gas and NGL prices and markets have been volatile, and those prices and markets are likely to continue to be volatile in the future. For example, during the period from January 1, 2021 through December 31, 2022, prices for crude oil and natural gas reached a high of $123.70 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.62 per Bbl and $2.43 per MMBtu, respectively. Oil prices steadily increased through 2021 due to continued recovery in demand before increasing drastically in the first half of 2022 due to further demand, domestic supply reductions, OPEC control measures and market disruptions resulting from the Russia-Ukraine war and sanctions on Russia. Since the Russia-Ukraine conflict first commenced, WTI crude oil prices have been volatile, rising from $92.81 per Bbl on February 24, 2022 to a high of $123.70 per Bbl in March 2022 before declining to $77.05 per Bbl as of February 28, 2023. Natural gas prices reached a high of $9.85 per MMbtu in August 2022 before declining to $2.50 per MMbtu as of February 28, 2023. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition, results of operations and cash available for distribution.

Unless we replace the reserves we produce, our revenues and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

We may be unable to pay quarterly distributions to our unitholders without substantial capital expenditures that maintain our asset base. Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future reserves and production and, therefore, our cash flow and ability to make distributions are highly dependent on our success in efficiently developing, optimizing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations and reduce cash available for distribution to our unitholders.

If commodity prices decline and remain depressed for a prolonged period, production from a significant portion of our properties may become uneconomic and cause downward adjustments of our reserve estimates and write downs of the value of such properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

Significantly lower commodity prices over extended periods of time may render many of our development projects uneconomic and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base and ability to borrow to fund our operations or make distributions to our unitholders. As a result, we may reduce the amount of distributions paid to our unitholders or cease paying distributions. In addition, a significant or sustained decline in commodity prices could hinder our ability to effectively execute our hedging strategy. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

Prior to 2021, our historical impairment of proved properties included $311.5 million of proved property impairments from 2014 through 2020. Due to the improvement in commodity pricing environment and industry conditions, we did not record any impairments in 2022 or 2021. However, if commodity prices fall below certain levels, our production, proved reserves and cash flows will be adversely impacted and we may be required to record additional impairments, which could be material. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our Credit Facility, which may be determined at the discretion of our lenders. See "—Any significant reduction in the borrowing base under our Credit Facility as a result of periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations."

Currently, our producing properties are concentrated in the Permian and San Juan Basins, making us vulnerable to risks associated with operating in a limited number of geographic

areas.

As a result of our geographic concentration, adverse industry developments in our operating areas could have a greater impact on our financial condition and results of operations than if we were more geographically diverse. We may also be disproportionately exposed to the impact of regional supply and demand factors, governmental regulations or midstream capacity constraints. Delays or interruptions caused by such adverse developments could have a material adverse effect on our financial condition and results of operations.

Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has recently been the case in our operating areas, we are subject to increasing competition for drilling rigs, workover rigs, tubulars and other well equipment, services and supplies as well as increased labor costs and a decrease in qualified personnel, which may lead to periodic shortages or delays. The curtailments arising from these and similar circumstances may last from a few days to several months and, in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

Drilling for and producing oil, natural gas and NGLs are high-risk activities with many uncertainties that could adversely affect our business, financial condition, results of operations and cash distributions to unitholders.

Our future financial condition and results of operations, and therefore our ability to make cash distributions to our unitholders, will depend on the success of our acquisition, development, optimization and exploitation activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable production.

Our decisions to purchase, develop, optimize or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- unexpected or adverse drilling conditions;
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements including permitting requirements, limitations on or resulting from wastewater discharge and the disposal of exploration and production wastes, including subsurface injections;
- elevated pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as hurricanes, lightning storms, flooding, tornadoes, snow or ice storms and changes in weather patterns;
- issues related to compliance with, or changes in, environmental and other governmental regulations;
- environmental hazards, such as oil and natural gas leaks, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;

- declines in oil, natural gas and NGL prices;
- the availability and timely issuance of required governmental permits and licenses; and

- title defects or legal disputes regarding leasehold rights.

We may be unable to make accretive acquisitions or successfully integrate acquired businesses or assets, and any inability to do so may disrupt our business and hinder our growth potential.

Our ability to grow and to increase distributions to our unitholders depends in part on our ability to make acquisitions that result in an increase in cash available for distribution. There is intense competition for acquisition opportunities in our industry and we may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition, do so on commercially acceptable terms or obtain sufficient financing to do so. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions.

In addition, our Credit Facility imposes certain limitations on our ability to enter into mergers or combination transactions and to make certain investments. Our Credit Facility also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement."

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Our failure to achieve consolidation savings, to successfully integrate the acquired businesses and assets into our existing operations or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential liabilities, including, but not limited to, environmental liabilities. Such assessments are inexact and inherently uncertain. For these reasons, the properties we have acquired or may acquire in the future may not produce as projected. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as pipe corrosion or groundwater contamination, when a review is performed. We may be unable to obtain contractual indemnities from any seller for liabilities arising from or attributable to the period prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Increased costs of capital could adversely affect our business.

Our business could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. For example, during 2022, the Federal Reserve raised the target range for the federal funds rate by 425 basis points to a range of 4.25% to 4.50% as of December 31, 2022, and in 2023 the target range has been increased again to a range of 4.75% to 5.00% as of March 2023 and the Federal Reserve and may increase it further. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our activities. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our business strategy and cash flows.

Drilling locations that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

We may in the future explore potential drilling locations in areas where we currently own properties and in other areas. These potential drilling locations would be in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively, prior to drilling, whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our other identified drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Because of these uncertain factors, we do not know if the potential well locations we have identified, or will identify, will ever be drilled or if we will be able to produce oil, natural gas and NGLs from these or any other potential locations. As such, our actual drilling activities may materially differ from those presently identified.

Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease or other interest in a specific mineral interest. The existence of a material title deficiency can render a lease or other interest worthless and can adversely affect our results of operations and financial condition. The failure of title on a lease, in a unit or any other mineral interest may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We operate certain of our properties through a joint venture over which we have shared control.

We conduct certain of our operations through Cross Timbers, a joint venture owned 50% by us and 50% by the XTO Entities. For the year ended December 31, 2022, our interest in Cross Timbers represented approximately 28% of our revenues excluding the effects of our commodity derivative contracts and approximately 33% of our proved reserves.

In accordance with the JV LLCA, Cross Timbers is managed by us and governed by a member management committee comprised of six members, three of whom are appointed by us and three of whom are appointed by the XTO Entities. The JV LLCA requires that certain matters, including certain material contracts or acquisitions, mergers, sale of substantially all assets or other change of control transactions, and transfers of our interest to a third party, be approved by unanimous consent of the voting members of the management committee and therefore such actions require the approval of the XTO Entities. Our ability to make distributions to our unitholders depends in part on the performance of this entity and its ability to distribute funds to us. We face certain risks associated with shared control, and the XTO Entities may at any time have economic, business or legal interests or goals that are inconsistent with ours.

We own non-operating interests in properties developed and operated by third parties and some of our leasehold acreage could be pooled by a third-party operator. As a result, we are unable, or may become unable as a result of pooling, to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other contractual arrangements. Similarly, our acreage in Colorado, Texas and New Mexico may be pooled by third-party operators under state law. If our acreage is involuntarily pooled under state forced pooling statutes, it would reduce our control over such acreage and we could lose operatorship over a portion of our acreage that we plan to develop.

We may not be able to maximize the value associated with acreage that we own but do not operate in the manner we believe appropriate, or at all. We cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator’s determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator’s operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator's failure to adequately perform operations, breach of applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our business, financial condition and results of operations.

Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate.

The majority of the scientific community has concluded that climate change may result in more frequent and/or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, which could affect some, or all, of our operations. Our development, optimization and exploitation activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes, thunderstorms, tornadoes and snow or ice storms, or other climate-related events such as wild fires, in each case which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions and events could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary resources, such as water, and third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

Declining general economic, business or industry conditions and inflation may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, supply chain disruptions, increased demand, labor shortages associated with a fully employed U.S. labor force, geopolitical issues, inflation, the availability and cost of credit and the United States financial market and other factors have contributed to increased economic uncertainty and diminished expectations for the global economy. Although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which has continued into 2023, due to a substantial increase in money supply, a stimulative fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Annual inflation for the year ended December 31, 2022 was 6.5%. Though we incorporated inflationary factors into our 2023 business plan, inflation may outpace those assumptions. We continue to undertake actions and implement plans to strengthen our supply chain to address these pressures and protect the requisite access to commodities and services. Nevertheless, we expect for the foreseeable future to experience supply chain constraints and inflationary pressure on our cost structure. Principally, commodity costs for steel and chemicals required for drilling, higher transportation and fuel costs and wage increases have increased our operating costs for the year ended December 31, 2022 compared to the year ended December 31, 2021. We also may face shortages of these commodities and labor, which may prevent us from executing our development plan. These supply chain constraints and inflationary pressures will likely continue to adversely impact our operating costs and, if we are unable to manage our supply chain, it may impact our ability to procure materials and equipment in a timely and cost-effective manner, if at all, which could impact our ability to distribute available cash and result in reduced margins and production delays and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

We continue to take actions to mitigate supply chain and inflationary pressures. We are working closely with other suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical suppliers which are critical to many of our operations. However, these mitigation efforts may not succeed or may be insufficient.

In addition, continued hostilities related to the Russian invasion of Ukraine and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors and other factors, such as another surge in COVID-19 cases or decreased demand from China, combined with volatile commodity prices, and declining business and consumer confidence may contribute to an economic slowdown and a recession. Recent growing concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our business, financial condition and results of operations.

Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, or the threat thereof, could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.

We face risks related to epidemics, outbreaks or other public health events, or the threat thereof, that are outside of our control, and could significantly disrupt our business and operational plans and adversely affect our liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units. The COVID-19 pandemic has adversely affected the global economy and has resulted in unprecedented governmental actions in the United States and countries around the world, including, among other things, social distancing guidelines, travel restrictions and stay-at-home orders, among other actions, which caused a significant decrease in activity in the global economy and the demand for oil, and to a lesser extent, natural gas and NGLs. Additionally, the effects of the COVID-19 pandemic might worsen the likelihood or the impact of other risks already inherent in our business. We believe that the known and potential impacts of the COVID-19 pandemic and related events include, but are not limited to, the following:

- disruption in the demand for oil, natural gas and other petroleum products;
- intentional project delays until commodity prices stabilize;
- potentially higher borrowing costs in the future;
- a need to preserve liquidity, which could result in a reductions, delays or changes in our capital expenditures;
- liabilities resulting from operational delays due to decreased productivity resulting from stay-at-home orders affecting our workforce or facility closures resulting from the COVID-19 pandemic;
- future asset impairments, including impairment of our natural gas properties, oil properties, and other property and equipment; and
- infections and quarantining of our employees and the personnel of vendors, suppliers and other third parties.

New variants of the virus could cause further commodity market volatility and resulting financial market instability, or any other event described above. These are variables beyond our control and may adversely impact our business, financial condition and results of operations.

We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk.

We periodically enter into futures contracts, energy swaps, options, collars and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas and natural gas liquids sales. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Derivatives.” By using derivative instruments to economically hedge exposure to changes in commodity prices, we could limit the benefit we would receive from increases in the prices for oil and natural gas, which could have an adverse effect on our financial condition. Likewise, to the extent our production is not hedged, we are exposed to declines in commodity prices, and our derivative arrangements may be inadequate to protect us from continuing and prolonged declines in commodity prices.

Changes in the fair value of commodity price derivatives are recognized currently in earnings. Realized and unrealized gains and losses on commodity derivatives are recognized in oil, NGL and natural gas revenues. Settlements of derivatives are included in cash flows from operating activities. While our price risk management activities decrease the volatility of cash flows, they may obscure our reported financial condition. As required under GAAP, we record derivative financial instruments at their fair value, representing projected gains and losses to be realized upon settlement of these contracts in subsequent periods when related production occurs. These gains and losses are generally offset by increases and decreases in the market value of our proved reserves, which are not reflected in the financial statements. For example, revenues increased $18.1 million, or 8%, from $228.3 million for the year ended December 31, 2021 to $246.4 million for the year ended December 31, 2022. The increase was primarily attributable to an increase in production of 1,246 MBoe primarily as a result of additional production from the acquired Vacuum properties and Andrews Parker properties, partially offset by decreased historical production of 248 MBoe. These increases were partially offset by losses on our hedging activity of $212.2 million, of which $122.2 million were unrealized losses and $90.0 million were realized losses.

Additionally, our Credit Facility may hinder our ability to effectively execute our hedging strategy. See "—Our Credit Facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement."

We also expose ourselves to credit risk resulting from the failure of the counterparty to perform under the terms of the applicable derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make it unable to perform under the terms of the contract and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil, natural gas and NGL reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

Furthermore, SEC rules require that, subject to limited exceptions, PUD reserves may only be recorded if they relate to wells scheduled to be drilled within five years after the date of booking. This rule may limit our potential to record additional PUD reserves as we pursue our drilling program. To the extent that natural gas and oil prices become depressed or decline materially from current levels, such condition could render uneconomic a number of our identified drilling locations, and we may be required to write down our PUD reserves if we do not drill those wells within the required five-year time frame. If we choose not to develop PUD reserves, or if we are not otherwise able to successfully develop them, then we will be required to remove the associated volumes from our reported proved reserves.

The preparation of reserve estimates requires the projection of production rates and the timing of development expenditures based on an analysis of available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may revise reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, may not represent the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. For example, our estimated proved reserves as of December 31, 2022 were calculated under SEC rules using the unweighted arithmetic average first day of the month prices for the prior 12 months of $6.36/MMBtu for natural gas and $93.67/Bbl for oil at December 31, 2022, which, for certain periods during this period, were substantially different from the available spot prices. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with Accounting Standards Codification 932, "*Extractive Activities—Oil and Gas*," may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

For the year ended December 31, 2022, Chevron USA and Phillips 66 Company accounted for more than 35% of our total revenues, excluding the impact of our commodity derivatives. For the year ended December 31, 2021, Phillips 66 Company, Tenaska Marketing and Eco-Energy, Inc. accounted for more than 40% of our total revenues, excluding the impact of our commodity derivatives. No other purchaser accounted for more than 10% of our revenue during such periods. We do not have long-term contracts with our customers; rather, we sell the substantial majority of our production under arm's length contracts with terms of 12 months or less, including on a month-to-month basis, to a relatively small number of customers. The loss of any one of these purchasers, the inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation could materially adversely affect our financial condition, results of operations and ability to make distributions to our unitholders. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have ready access to suitable markets for our future production. See "Business and Properties—Operations—Marketing and Customers."

The availability of a ready market for any hydrocarbons we produce depends on numerous factors beyond our control, including, but not limited to, the extent of domestic production and imports of oil, the proximity and capacity of natural gas and NGL pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil, natural gas and NGL production and federal regulation of oil, natural gas and NGLs sold in interstate commerce.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with companies that possess and employ financial, technical and personnel resources substantially greater than ours. Our ability to acquire additional properties and to exploit reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations and our ability to make distributions to our unitholders.

Our Credit Facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

Our Credit Facility restricts, among other things, our ability to:

- incur certain liens or permit them to exist;
- merge or consolidate with another company;
- incur or guarantee additional debt;
- make certain investments and acquisitions;
- make or pay distributions on, or redeem or repurchase, common units, if an event of default or borrowing base deficiency exists;
- enter into certain types of transactions with affiliates; and
- transfer, sell or otherwise dispose of assets.

In addition, our Credit Facility will require us to comply with customary financial covenants and specified financial ratios, including that we maintain (i) a current ratio greater than 1.0 to 1.0 and (ii) a ratio of total indebtedness-to-EBITDAX of not greater than 3.00 to 1.00. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our Credit Facility that are not cured or waived within specific time periods, our lender may declare our indebtedness thereunder to be immediately due and payable, our ability to make distributions to our unitholders will be inhibited and our lenders' commitment to make further loans to us may terminate. Any such acceleration of such debt could also result in a cross-acceleration of other future indebtedness which we may incur. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our Credit Facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our Credit Facility, the lenders could seek to foreclose on our assets or force us to seek bankruptcy protection.

In addition, our Credit Facility may hinder our ability to effectively execute our hedging strategy. Our Credit Facility limits the maximum percentage of our production that we can hedge and the duration of those hedges, so we may be unable to enter into additional commodity derivative contracts during favorable market conditions and, thus, unable to lock in attractive future prices for our product sales. Conversely, our Credit Facility also requires us to hedge a minimum percentage of our production, which may cause us to enter into commodity derivative contracts at inopportune times. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

Any significant reduction in the borrowing base under our Credit Facility as a result of periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our Credit Facility limits the amount we can borrow up to a borrowing base amount. The administrative agent under our Credit Facility determines our borrowing base based on the value of our oil and natural gas properties. The borrowing base is subject to further adjustments for asset dispositions, material title deficiencies, certain terminations of hedge agreements and issuances of permitted additional indebtedness. As of November 3, 2022, the last date of redetermination, our borrowing base was $165 million. Such amount will be redetermined semi-annually on or before each March 15 and September 1 and will depend on the volumes of our proved oil and natural gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under the Credit Facility, including our business, financial condition and debt obligations, the types of reserves, the value and effect of hedge contracts then in effect and the effect of gas imbalances. In addition, our lenders will have flexibility to reduce our borrowing base due to subjective factors. Our next borrowing base redetermination is scheduled for to be completed no later than June 30, 2023.

In the future, we may not be able to access adequate funding under our Credit Facility (or a replacement facility) as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of our lenders to meet their funding obligations. Declines in commodity prices could result in a determination by the lenders to decrease the borrowing base in the future and, in such a case, we could be required to promptly repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which could have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our debt arrangements, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our Credit Facility, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. If oil, natural gas and NGL prices decline for an extended period of time, we may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional equity or debt capital or restructure or refinance indebtedness or seek bankruptcy protection to facilitate a restructuring. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt or preferred equity arrangements may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our Credit Facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition in certain circumstances. We may not be able to consummate these dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may prevent us from meeting scheduled debt service obligations.

Our level of indebtedness may increase and reduce our financial flexibility.

We may incur significant indebtedness, whether through future debt issuances or by drawing down on the availability under our Credit Facility, in the future in order to make acquisitions or to develop our properties or for other general corporate purposes. Such indebtedness could affect our operations in several ways:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay distributions on our common units and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a significant portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, or other general corporate purposes.

A high level of indebtedness, if incurred in the future, increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness in such event depends on our future performance. General economic conditions, commodity prices, and financial, business, and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, borrowings, or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our common units or a refinancing of our debt include financial market conditions (including any financial crisis), the value of our assets, and our performance at the time we need capital.

Our drilling and production programs may not be able to obtain access to truck transportation, pipelines and storage facilities, natural gas gathering facilities, and other transportation, processing and refining facilities to market our oil, natural gas and NGL production, and our initiatives to expand our access to midstream and operational infrastructure may be unsuccessful.

The marketing of oil, natural gas and NGL production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, natural gas gathering systems and other transportation, processing and refining facilities. In order to market new or increased production, new facilities or expanded capacity on existing facilities may be required. Access to transportation, processing, and refining facilities, whether new or existing, is, in many respects, beyond our control. If these facilities are unavailable to us because we are unable to obtain services on commercially reasonable terms, the owners and operators of such facilities are unable to obtain permits for new or expanded capacity in compliance with environmental and other governmental or regulatory requirements or are delayed in obtaining such permits, or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil, natural gas and NGL production.

Increases in activity in our operating areas could, in the future, contribute to bottlenecks in processing and transportation that could negatively affect our results of operations, and these adverse effects could be disproportionately severe to us compared to our more geographically diverse competitors. As a result, our business, financial condition and results of operations could be adversely affected.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flows and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for experienced development crews and oil field equipment and services and materials as drilling activity increases; and increased taxes, which could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and reduce our cash available for distribution to our unitholders. Decreased levels of drilling activity in the oil and natural gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flows and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

We are highly dependent on the services of our senior management and the loss of senior management or technical personnel could adversely affect our operations.

We depend on the services of our senior management and technical personnel. Our management team has an average of 32 years’ experience in the oil and gas industry. There can be no assurance that we would be able to replace such members of management with comparable replacements or that such replacements would integrate well with our existing team. Further, the loss of the services of our senior management could have a material adverse effect on our business, financial condition and results of operations. In particular, the loss of the services of one or more members of our management team could disrupt our operations. We do not maintain, nor do we plan to obtain, “key person” life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Our continued success will depend, in part, on our ability to attract and retain experienced technical personnel, including geologists, engineers and other professionals. Large numbers of technical personnel in the oil and gas industry are approaching the normal retirement age of 65 or otherwise accepted an early retirement during the COVID-19 pandemic. These and other factors may lead to a shortage of qualified, entry-level technical personnel and increased compensation costs. The foregoing factors may lead to additional competition from oil and gas companies attempting to meet their hiring needs. If a shortage of technical personnel materializes, companies in the oil and gas industry may be unable to hire adequate numbers of technical personnel to meet their needs, resulting in disruptions, increased costs of operations, financial difficulties and other adverse effects, and these circumstances may become more severe in the future and thereby cause a material adverse effect on our business.

Past performance by our management team may not be indicative of future performance of an investment in us.

Information regarding performance by, or businesses associated with, TXO Energy Partners and its affiliates is presented for informational purposes only. Past performance by TXO Energy Partners and its affiliates, including our management team, is not a guarantee of future performance. You should not rely on the historical record of TXO Energy Partners and its affiliates or our management team’s prior performance as indicative of our future performance or the returns we will, or are likely to, generate going forward.

We are responsible for the decommissioning, abandonment, and reclamation costs for our facilities, which could decrease our cash available for distribution.

We are responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of our facilities at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, abandonment and reclamation. We may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund one or more decommissioning, abandonment and reclamation reserve funds to provide for payment of future decommissioning, abandonment and reclamation costs, which could decrease our cash available for distribution. In addition, such reserves, if established, may not be sufficient to satisfy such future decommissioning, abandonment and reclamation costs and we will be responsible for the payment of the balance of such costs.

Asset retirement obligations for our oil and gas assets and properties are estimates, and actual costs could vary significantly.

We are required to record a liability for the discounted present value of our estimated asset retirement obligations to plug and abandon inactive wells and related assets and non-producing oil and gas properties in which we have a working interest. Such asset retirement obligations may include complete structural removal and/or restoration of the land. At December 31, 2022, we had accrued asset retirement obligations of $126.5 million. Although management has used its best efforts to determine future asset retirement obligations, assumptions and estimates can be influenced by many factors beyond management’s control, including, but not limited to, changes in regulatory requirements, which may be more restrictive in the future, changes in costs for abandonment related services and technologies, which could increase or decrease based on supply and demand, and/or extreme weather conditions, such as hurricanes and lightning storms, which may cause structural or other damage to oil and natural gas assets and properties. Accordingly, our estimate of future asset retirement obligations could differ materially from actual costs that may be incurred.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil, natural gas and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, phishing, ransomware, attempts to gain unauthorized access to data and systems, 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. These events could lead to financial losses from remedial actions, loss of business or potential liability. Although we maintain insurance to protect against losses resulting from certain data protection breaches and cyber-attacks, our coverage for protecting against such risks may not be sufficient.

In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period, and our systems and insurance coverage for protecting against such cybersecurity risks may be costly and may not be sufficient. As cyber-attackers become more sophisticated, we may be required to expend significant additional resources to continue to protect our business or remediate the damage from cyber-attacks. Furthermore, the continuing and evolving threat of cyber-attacks has resulted in increased regulatory focus on prevention, and we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. To the extent we face increased regulatory requirements, we may be required to expend significant additional resources to meet such requirements.

We are subject to a number of privacy and data protection laws, rules and directives (collectively, data protection laws) relating to the processing of personal data.

The regulatory environment surrounding data protection laws is uncertain. Varying jurisdictional requirements could increase the costs and complexity of compliance with such laws, and violations of applicable data protection laws can result in significant penalties. A determination that there have been violations of applicable data protection laws could expose us to significant damage awards, fines and other penalties that could materially harm our business and reputation.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance and adversely affect our business. As noted above, we are also subject to the possibility of security and privacy breaches, which themselves may result in a violation of these laws. Additionally, the acquisition of a company that is not in compliance with applicable data protection laws may result in a violation of these laws.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, an inability to find, produce, process and sell oil, natural gas and NGLs and an inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Our acquisition, development, optimization and exploitation projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves.

The oil, natural gas and NGL industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, development, optimization and exploitation of oil and natural gas reserves. Funding sources for our capital expenditures have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. Our management has collectively invested more than $500 million in us since our inception. We expect that we will not be able to rely on our management or our partners for capital and will need to utilize the public equity or debt markets and bank financings to fund acquisitions and capital expenditures. We expect to fund our 2023 capital expenditures with cash generated by operations; however, our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves;
- the extent and levels of our derivative activities;
- the levels of our operating expenses; and
- our ability to borrow under our Credit Facility.

If our revenues or the borrowing base under our Credit Facility decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. Even if we can obtain debt financing on terms acceptable to us, the issuance of additional indebtedness would require that a portion of our cash flows from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions. Additionally, the market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our capital expenditures with the issuance of additional equity. The issuance of additional equity securities may be dilutive to our unitholders. If cash flows generated by our operations are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition and results of operations. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

Continuing political and social concerns about the issues of climate change may result in changes to our business and significant expenditures, including litigation-related expenses.

Increasing attention to global climate change has resulted in increased investor attention and an increased risk of public and private litigation, which could increase our costs or otherwise adversely affect our business. Governmental and other entities in various states, such as California and New York, have filed lawsuits against coal, gas oil and petroleum companies. These suits allege damages for contributions to, or failure to disclose the impact of, climate change, and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Similar lawsuits may be filed in other jurisdictions both in the United States and globally. Though we are not currently a party to any such lawsuit, these suits present uncertainty regarding the extent to which companies engaged in oil and gas production face an increased risk of liability stemming from climate change, which risk would also adversely impact the oil and gas industry and impact demand for our services. The ultimate outcome and impact to us of any such litigation cannot be predicted with certainty, and we could incur substantial legal costs associated with defending any potential similar lawsuits in the future. See “Business and Properties—Regulation of GHG Emissions (Climate Change)” for a further description of the laws and regulations that affect us.

Risks Related to Environmental and Regulatory Matters

We are subject to stringent federal, state and local laws and regulations related to environmental and occupational health and safety issues that could adversely affect the cost or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are subject to numerous stringent federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and the protection of the environment and natural resources (including threatened and endangered species). These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting drilling and other regulated activities; the restriction of types, quantities and concentration of materials that may be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations, and reclamation and restoration costs. Numerous governmental authorities, such as the U.S. Environmental Protection Agency (“EPA”) and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations or specific projects and limit our growth and revenue.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties. Spills or other releases of regulated substances, including such spills and releases that occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. We may not be able to recover some or any of these costs from insurance. The trend in environmental regulation has been towards more stringent requirements, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition. For example, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple sites into a single source for air quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements.

In October 2015, the EPA issued a new lower National Ambient Air Quality Standard ("NAAQS") for ground level ozone of 70 parts per billion. In 2017, the EPA designated certain counties in southeastern New Mexico and West Texas located in the Permian Basin attainment/unclassifiable for the 2015 ozone NAAQS. However, in June 2022, EPA announced that it is considering a discretionary redesignation for these counties based on current monitoring data and other air quality factors. If the Permian Basin counties in which we operate were redesignated as nonattainment areas, this could subject us to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements and increased permitting delays and costs.

The EPA has also imposed increasingly stringent performance standards on oil and gas operations. In 2016, the EPA issued regulations under NSPS OOOOa that require operators to reduce methane and volatile organic compound (“VOC”) emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector. The proposed rule would establish standards of performance for sources that commence construction, modification or reconstruction after the date the proposed rule was published in the Federal Register and would establish emissions guidelines, which will inform state plans to establish standards for existing sources. The EPA issued a supplemental proposed rule in November 2022 to update, strengthen and expand its November 2021 proposed rule. The supplemental proposed rule would impose more stringent requirements on the oil and natural gas industry, and is expected to be finalized in 2023. The Bureau of Land Management (“BLM”) also issued a proposed rule in November 2022 to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on federal and American Indian leases. State agencies have similarly imposed increasing restrictions on emissions from oil and gas operations. For example, in 2022, the New Mexico Environment Department adopted new regulations establishing emission reduction requirements for storage vessels, compressors, turbines, heaters, engines, dehydrators, pneumatic devices, produced water management units, and other equipment and processes. Compliance with these more stringent standards and other environmental regulations at the federal or state levels could delay or prohibit our ability to obtain permits for operations or require us to install additional pollution control equipment, the costs of which could be significant. See “Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters” for a further description of the laws and regulations that affect us.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005 (“EPAct 2005”), the Federal Energy Regulatory Commission (the “FERC”) has civil penalty authority under the Natural Gas Act of 1938 (“NGA”) to impose penalties for current violations of $1,496,035 per violation per day. The FERC may also impose administrative and criminal remedies and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and regulations pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the Federal Trade Commission (“FTC”) has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1,426,319 per violation per day, and the Commodity Futures Trading Commission (“CFTC”) prohibits market manipulation in the markets regulated by the CFTC, including similar anti manipulation authority with respect to swaps and futures contracts as that granted to the CFTC with respect to oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1,404,520 or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in “Business—Regulation of the Oil and Natural Gas Industry.”

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil, natural gas and NGL exploration and production activities, and reduce demand for the oil, natural gas and NGLs we produce.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that greenhouse gas (“GHG”) emissions constitute a pollutant under the Clean Air Act (the “CAA”), the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, and together with the Department of Transportation (the “DOT”), implement GHG emissions limits on vehicles manufactured for operation in the United States. The federal government has also increased regulation of methane from oil and gas facilities in recent years. For example, in 2016, the EPA issued regulations under NSPS OOOOa that require operators to reduce methane and VOC emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector. The proposed rule would establish standards of performance for sources that commence construction, modification or reconstruction after the date the proposed rule was published in the Federal Register and would establish emissions guidelines, which will inform state plans to establish standards for existing sources. The EPA issued a supplemental proposed rule in November 2022 to update, strengthen and expand its November 2021 proposed rule. The supplemental proposed rule would impose more stringent requirements on the oil and natural gas industry, and is expected to be finalized in 2023. The BLM also issued a proposed rule in November 2022 to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on federal and American Indian leases. If finalized, these increasingly stringent methane and VOC requirements on new facilities, or the application of new requirements to existing facilities, could result in additional restrictions on our operations and increased compliance costs, which could be significant. Additionally, the Inflation Reduction Act, recently passed by Congress and signed into law by President Biden in 2022, imposes several new requirements on oil and gas operators, including a fee for leaks or venting of methane, starting at $900 per ton in 2024 and rising to $1,500 per ton in and after 2026, from certain facilities. The act also appropriates significant federal funding for renewable energy initiatives. These developments may make it harder for the oil and gas industry to attract capital. Given the long-term trend toward increasing regulation, we expect there will be additional future federal GHG regulations of the oil and gas industry.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. For example, the New Mexico Oil Conservation Commission has adopted regulations to restrict the venting or flaring of methane from both upstream and midstream operations. Internationally, the United Nations-sponsored “Paris Agreement” requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States’ emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change (“COP26”), during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-CO_2 GHGs. Relatedly, the United States and European Union jointly announced the launch of the “Global Methane Pledge,” which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including “all feasible reductions” in the energy sector. While there were limited announcements at COP27, which took place in November 2022 in Sharm-El Sheik, with respect to the reduction of fossil fuel use, there were negotiations on emissions reduction targets and reduction of fossil fuel use amongst the international community, and it is likely that these discussions will continue at COP28. The impact of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States’ commitments under the Paris Agreement, COP26, or other international conventions cannot be predicted at this time. However, to the extent these developments result in new restrictions on oil and gas operations, increase operational costs, or otherwise reduce the demand for oil and gas, they could have a material adverse effect on our business.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates elected to public office. President Biden has issued several executive orders focused on addressing climate change, including items that may impact our costs to produce, or demand for, oil and gas. Additionally, in November 2021, the Biden Administration released “The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050,” which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO_2 GHG emissions, such as methane and nitrous oxide. The Biden Administration is also considering revisions to the leasing and permitting programs for oil and gas development on federal lands.

Litigation risks are also increasing, as a number of entities have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change. Suits have also been brought against such companies under shareholder and consumer protection laws, alleging that companies have been aware of the adverse effects of climate change but failed to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero

(“GFANZ”) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Various U.S. financial regulators have announced that they are considering climate-related regulations and, separately, the Federal Reserve has joined the Network for Greening the

Financial System, 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. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Additionally, the SEC has proposed new rules relating to the disclosure of a range of climate-change-related physical and transition risks, data and opportunities. The proposed rule contains several new disclosure obligations, including (i) disclosure on an annual basis of a registrant’s scope 1 and scope 2 greenhouse gas emissions, (ii) third-party independent attestation of the same for accelerated and large accelerated filers, (iii) for some registrants, disclosure on an annual basis of a registrant’s scope 3 greenhouse gas emissions for accelerated and large accelerated filers, (iv) disclosure on how the board of directors and management oversee climate-related risks and certain climate-related governance items, (v) disclosure of information related to a registrant’s climate-related targets, goals and/or transitions plans and (vi) disclosure on whether and how climate-related events and transition activities impact line items above a threshold amount on a registrant’s consolidated financial statements, including the impact of the financial estimates and the assumptions used. While we would likely be subject to the longer proposed phase-in for the reporting requirements as an emerging growth company, we are currently assessing this rule and cannot predict the costs of implementation or any potential adverse impacts resulting from the rule should it be adopted as proposed; however, we expect these costs to be substantial. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon intensive sectors.

The adoption and implementation of new or more stringent international, federal, regional or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, international, federal, regional or state legislation, regulation or other initiatives could make alternative forms of energy more attractive in comparison to oil and natural gas, and thereby reduce demand for oil and natural gas. Moreover, political, litigation and financial risks may result in our restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

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

Increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG initiatives and disclosures, and consumer demand for alternative forms of energy may result in increased costs, including, but not limited to, increased costs related to compliance, stakeholder engagement, contracting and insurance, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on the price of our common units and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us or our operators. 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 the asserted damage, or to other mitigating factors.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters in the future, many of the statements in those voluntary disclosures may be on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. 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 and measuring many ESG matters. Such disclosures may also be partially reliant on third-party information that we have not or cannot independently verify. In addition, we expect there will likely be increasing levels of regulation, disclosure-related and otherwise, with respect to ESG matters, and increased regulation will likely to lead to increased compliance costs as well as scrutiny that could heighten all of the risks identified in this risk factor.

In addition, organizations that voluntarily provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with fossil fuel energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investments to other industries, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

Moreover, 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 suppliers or customers, which may adversely impact our business, financial condition, or results of operations.

We may face various risks associated with the long-term trend toward increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil and gas shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling and hydraulic fracturing in the United States, even in jurisdictions that are among the most stringent in their regulation of the industry. Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms and reduction in lease size;
- restrictions on installation or operation of production, gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or disposal of related waste materials, such as hydraulic fracking fluids and production;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about our business or the oil and gas industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

We may need to incur significant costs associated with responding to these initiatives, and there is no guarantee that our responses will have the intended results. Complying with any resulting additional legal or regulatory requirements that are substantial could have a material adverse effect on our business, financial condition, cash flows, results of operations and ability to pay distributions on our common units.

Prolonged negative investor sentiment toward upstream natural gas and oil focused companies could limit our access to capital funding, which would constrain liquidity.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other sectors have led to lower natural gas and oil representation in certain key equity market indices. Some investors, including certain pension funds, private equity funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the natural gas and oil sector based on social and environmental considerations. Certain other stakeholders have pressured commercial and investment banks to stop directly funding or raising capital for hydrocarbon extraction, transportation or refining. If this negative sentiment continues or worsens, it may reduce the availability of capital funding for potential development projects, each of which could have a material adverse effect our financial condition, results of operations, cash flows and ability to pay distributions on our common units.

Conservation measures and technological advances could reduce demand for oil, natural gas and NGLs.

Fuel conservation measures, alternative fuel requirements, increasing availability of, and consumer and industrial/commercial demand for, alternatives to oil, natural gas and NGLs (e.g., alternative energy sources) and products manufactured with, or powered by, non-oil and gas sources (e.g., electric vehicles and renewable residential and commercial power supplies), and technological advances in fuel economy and energy generation, transmission, storage and consumption of energy (e.g., wind, solar and hydrogen power, smart grid technology and battery technology), including incentives contained in the Inflation Reduction Act, could reduce demand for oil, natural gas and NGLs. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, our business could be impacted by other governmental initiatives to incentivize the conservation of energy or the use of alternative energy sources. For example, in November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO_2 GHG emissions, such as methane and nitrous oxide. Further, the U.S. Department of Transportation recently issued more stringent fuel economy standards. These initiatives or similar state or federal initiatives to reduce energy consumption or incentivize a shift away from fossil fuels could reduce demand for hydrocarbons and have a material adverse effect on our earnings, cash flows and financial condition.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of unconventional natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Nearly all of our operated wells are drilled conventionally; however, from time to time, a small percentage of our wells are horizontally completed.

Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing CAA performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published in June 2016 an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. To date, the EPA has taken no further action in response to the December 2016 report. In addition, the BLM finalized rules in March 2015 establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands, including well casing and wastewater storage requirements and an obligation for exploration and production operators to disclose what chemicals they are using in fracturing activities. In December 2017, BLM issued a final rule repealing the 2015 hydraulic fracturing rule. The BLM's rescission of the rule was challenged by several environmental groups and states in the United States District Court for the Northern District of California. The United States District Court for the Northern District of California upheld the BLM's recission in a March 2020 decision. Additionally, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Meanwhile, states have continued to regulate hydraulic fracturing.

In the event that new federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may incur additional costs to comply with such requirements when horizontally completing wells, which may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities, which could in turn have a material adverse effect on our business and results of operations.

See "Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters" for a further description of the laws and regulations that affect us.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us to incur costs or take other measures which may materially impact our business or operations. See "Business and Properties—Endangered Species and Migratory Birds Considerations" for a further description of the laws and regulations that affect us.

The third parties on whom we rely for transportation services are subject to complex federal, state, tribal and local laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely 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, tribal 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 we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to our unitholders. Please read "Business and Properties—Environmental Matters and Regulation" and "Business and Properties—Regulation of the Oil and Natural Gas Industry" for a description of the laws and regulations that affect the third parties on whom we rely.

Derivatives regulation could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over the counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC has adopted rules that place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. These limitations could increase the costs to us of entering into, or lessen the availability of, derivative contracts to hedge or mitigate our exposure to volatility in oil, gas and NGL prices and other commercial risks affecting our business. The Dodd-Frank Act and CFTC rules will also require us, in connection with certain derivatives activities, to comply with clearing and trade execution requirements (or to qualify for an exemption to such requirements). In addition, the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end user exception to the mandatory clearing, trade execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, if any of our swaps do not qualify for the commercial end user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow. It is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

We may be involved in legal proceedings that could result in substantial liabilities.

Like many oil and natural gas companies, we are, from time to time, involved in various legal and other proceedings in the ordinary course of our business, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and under insured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, natural gas and NGLs, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- well blowouts;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapses;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and

- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Also, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or fully covered by insurance and any delay in the payment of insurance proceeds for covered events could have a material adverse effect on our business, financial condition and results of operations.

Limitation or restrictions on our ability to obtain water may have an adverse effect on our operating results.

Water is an essential component of shale oil and natural gas development during both the drilling and hydraulic fracturing processes. Our access to water to be used in these processes may be adversely affected due to reasons such as periods of extended drought, private, third party competition for water in localized areas or the implementation of local or state governmental programs to monitor or restrict the beneficial use of water subject to their jurisdiction for hydraulic fracturing to assure adequate local water supplies. In addition, treatment and disposal of water is becoming more highly regulated and restricted. Thus, our costs for obtaining and disposing of water could increase significantly. In addition, the use, treatment and disposal of water has become a focus of certain investors and other stakeholders who may seek to engage with us on this and other environmental matters, which may result in activism, negative reputational impacts, increased costs or other adverse effects on our business, results of operations and financial condition. Our inability to locate or contractually acquire and sustain the receipt of sufficient amounts of water could adversely impact our exploration and production operations and have a corresponding adverse effect on our business, results of operations and financial condition.

Risks Inherent in an Investment in Us

Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Our general partner has control over all decisions related to our operations. Bob R. Simpson, our Chief Executive Officer and Chairman, Brent W. Clum, our President of Business Operations, Chief Financial Officer and Director, Keith A. Hutton, our President of Production and Development and Director, and Vaughn O. Vennerberg II, our former President, (collectively, the “Founders”) own all of the membership interests in the sole member of our general partner. The Founders also own an aggregate of approximately 26% of our outstanding common units. Although our general partner has a duty to manage us in a manner that is not adverse to the best interests of us and our unitholders, the executive officers and directors of our general partner also have a duty, in certain cases, to manage our general partner at the direction of MSOG, which is owned by the Founders. As a result of these relationships, conflicts of interest may arise in the future between the Founders and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of us and our common unitholders. These conflicts include, among others, the following:

- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner’s liabilities and restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- Neither our partnership agreement nor any other agreement requires the Founders or their respective affiliates (other than our general partner) to pursue a business strategy that favors us;

- The Founders and their affiliates are not limited in their ability to compete with us, including with respect to future acquisition opportunities, and are under no obligation to offer or sell assets to us;

- Our general partner determines the amount and timing of our development operations and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other partnerships with which our general partner is or may become affiliated, and cash reserves, each of which can affect the amount of cash that is distributed to unitholders;

- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- Our general partner determines which costs incurred by it and its affiliates 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 to us or entering into additional contractual arrangements with any of these entities on our behalf;
- Our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- Our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement does not restrict our Founders and their respective affiliates from competing with us. Certain of our directors and officers may in the future spend significant time serving, and may have significant duties with, investment partnerships or other private entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. Affiliates of our general partner are not prohibited from owning projects or engaging in businesses that compete directly or indirectly with us. Similarly, our partnership agreement does not limit our Founders' or their respective affiliates' ability to compete with us and our Founders do not have any obligation to present business opportunities to us.

In addition, certain of our officers and directors may in the future hold similar positions with investment partnerships or other private entities that are in the business of identifying and acquiring mineral and royalty interests. In such capacities, these individuals would likely devote significant time to such other businesses and would be compensated by such other businesses for the services rendered to them. The positions of these directors and officers may give rise to duties that are in conflict with duties owed to us. In addition, these individuals may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may be affiliated. Due to these potential future affiliations, they may have duties to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. Our Founders and their respective affiliates will be under no obligation to make any acquisition opportunities available to us.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors, our Founders and their respective affiliates. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and holders of our common units.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow our reserves and production and make acquisitions.

Our partnership agreement provides that we distribute each quarter all of our available cash, which we define as cash on hand at the end of the each quarter, less reserves established by our general partner. As a result, we expect to rely primarily upon our cash reserves and external financing sources, including the issuance of additional common units and other partnership securities and borrowings under our Credit Facility, to fund future acquisitions and finance our growth.

To the extent we are unable to finance growth with our cash reserves and external sources of capital, the requirement in our partnership agreement to distribute all of our available cash may impair our ability to grow.

A number of factors will affect our ability to issue securities and borrow money to finance growth, as well as the costs of such financings, including:

- general economic and market conditions, including interest rates, prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and gas industry;
- the market price of, and demand for, our common units;
- our results of operations and financial condition; and
- prices for oil, natural gas and NGLs.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or our Credit Facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement replaces our general partner's fiduciary duties to us and our unitholders with contractual standards governing its duties, and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with different contractual standards. For example, our partnership agreement provides that:

- whenever our general partner (acting in its capacity as our general partner), the Board or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was not adverse to our best interests, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or equitable principle;
- our general partner may make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners at the time our partnership agreement was entered into where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:
    - how to allocate corporate opportunities among us and its other affiliates;
    - whether to exercise its limited call right;

- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board;
- how to exercise its voting rights with respect to the units it owns;

  - whether to sell or otherwise dispose of any units or other partnership interests it owns; and
  - whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

- our general partner will not have any liability to us or our unitholders for breach of any duty in connection with decisions made in its capacity as general partner so long as it acted in good faith (meaning that it subjectively believed that the decision was not adverse to our best interest);
- 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 our general partner or its officers and directors acted in bad faith or engaged in intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
  - approved by the conflicts committee of the Board, although our general partner is not obligated to seek such approval;
  - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
  - determined by the Board to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
  - determined by the Board to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the Board determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth sub-bullet points above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity and incur debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. In addition, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions to our unitholders and implied distribution yield. This implied distribution yield is often used by investors to compare and rank similar yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity or incur debt. See “—Increased costs of capital could adversely affect our business.”

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to permit the general partner to redeem the units of certain non-citizen unitholders.

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to obtain proof of the U.S. federal income tax status and/or the nationality, citizenship or other related status of our limited partners (and their owners, to the extent relevant) and to permit our general partner to redeem the units held by any person (i) whose nationality, citizenship or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (ii) who fails to comply with the procedures established to obtain such proof. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Our unitholders have limited voting rights and are not entitled to elect our general partner or the Board, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, 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 will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The Board, including the independent directors, is chosen entirely by the Founders, as a result of their ownership of our general partner, and not by our unitholders. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our general partner has control over all decisions related to our operations. Since affiliates of our general partner (including the Founders) collectively own and control the voting of an aggregate of approximately 38% of our outstanding common units, the other unitholders will not have an ability to influence any operating decisions and will not be able to prevent us from entering into any transactions. However, our partnership agreement can generally be amended with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including common units held by the affiliates of our general partner (including the Founders)). Assuming we do not issue any additional common units and the affiliates of our general partner (including the Founders) do not transfer any of their common units, the affiliates of our general partner (including the Founders) will generally have the ability to significantly influence any amendment to our partnership agreement, including our policy to distribute all of our cash available for distribution to our unitholders. Furthermore, the goals and objectives of the affiliates of our general partner (including the Founders) that hold our common units relating to us may not be consistent with those of a majority of the other unitholders. Please read "—Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders."

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

The public unitholders will be unable initially to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent the removal of our general partner. The vote of the holders of at least 66 $\frac{2}{3}$% of all outstanding units voting together as a single class is required to remove our general partner. Affiliates of our general partner (including the Founders) own approximately 38% of our outstanding voting units , which will enable those holders, collectively, to prevent the removal of our general partner.

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. Furthermore, our partnership agreement does not restrict the ability of the Founders, who own MSOG, which wholly owns our general partner, from transferring all or a portion of their ownership interests in MSOG (or from causing MSOG to transfer all or a portion of its ownership interest in our general partner) to a third party. The new owner of our general partner would then be in a position to replace the Board and officers of our general partner with their own choices and thereby influence the decisions made by the Board and officers.

We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- our unitholders’ proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;

- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' limited voting rights by providing that any common units held by a person, entity or group owning 20% or more of any class of common units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such common units with the prior approval of the Board, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the ability of our common unitholders to influence the manner or direction of management.

Affiliates of our general partner may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

Affiliates of our general partner (including the Founders) own 11,572,649 common units, or approximately 38% of our limited partner interest. Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership interests proposed to be sold by our general partner or any of its affiliates, which includes the Founders. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

If at any time our general partner and its affiliates own more than 80% of the then outstanding common 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 common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its call right. If our general partner exercises its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act. Affiliates of our general partner own approximately 38% of our common units.

Our partnership agreement has designated the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders which would limit our unitholders' ability to choose the judicial forum for disputes with us or our general partner or its directors, officers or other employees.

Our partnership agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court in the State of Delaware with subject matter jurisdiction) will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners, (4) asserting a claim arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") or (5) asserting a claim against us governed by the internal affairs doctrine. The foregoing provision will not apply to any claims as to which the Court of Chancery determines that there is an indispensable party not subject to the jurisdiction of such court, which is rested in the exclusive jurisdiction of a court or forum other than such court (including claims arising under the Exchange Act), or for which such court does not have subject matter jurisdiction, or to any claims arising under the Securities Act and, unless we consent in writing to the selection of an alternative forum, the United States federal district courts will be the sole and exclusive forum for resolving any action asserting a claim arising under the Securities Act. Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules or regulations thereunder. Accordingly, both state and federal courts have jurisdiction to entertain such Securities Act claims. To prevent having to litigate claims in multiple jurisdictions and the threat of inconsistent or contrary rulings by different courts, among other considerations, the partnership agreement provides that, unless we consent in writing to the selection of an alternative forum, United States federal district courts shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under the Securities Act. There is uncertainty as to whether a court would enforce the forum provision with respect to claims under the federal securities laws. If a court were to find these provisions of our amended and restated agreement of limited partnership inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

Our partnership agreement also provides that each limited partner waives the right to trial by jury in any such claim, suit, action or proceeding, including any claim under the U.S. federal securities laws, to the fullest extent permitted by applicable law. If a lawsuit is brought against us under our partnership agreement, it may be heard only by a judge or justice of the applicable trial court, which would be conducted according to different civil procedures and may result in different outcomes than a trial by jury would have, including results that could be less favorable to the plaintiffs in any such action. No unitholder can waive compliance with respect to the U.S. federal securities laws and the rules and regulations promulgated thereunder. If the partnership or one of the partnership unitholders opposed a jury trial demand based on the waiver, the applicable court would determine whether the waiver was enforceable based on the facts and circumstances of that case in accordance with applicable state and federal laws. To our knowledge, the enforceability of a contractual pre-dispute jury trial waiver in connection with claims arising under the U.S. federal securities laws has not been finally adjudicated by the United States Supreme Court. However, we believe that a contractual pre-dispute jury trial waiver provision is generally enforceable, including under the laws of the State of Delaware, which govern our partnership agreement. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations, provisions and obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. These provisions may have the effect of discouraging lawsuits against us, our general partner and our general partner’s directors and officers.

The NYSE does not require a publicly traded partnership like us to comply, and we do not intend to comply, with certain of its governance requirements generally applicable to corporations.

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, unitholders will not have the same protections afforded to stockholders of certain corporations that are subject to all of the NYSE’s corporate governance requirements.

Our unitholders’ liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a Delaware limited partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. 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 other states in which we do business. A unitholder could be liable for our obligations as if it was a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state’s partnership statute; or

- a unitholder’s right to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes “control” of our business.

Our unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make distributions to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If our common unit price declines, our unitholders could lose a significant part of their investment.

The market price of our common units is influenced by many factors, some of which are beyond our control. The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in commodity prices;
- changes in securities analysts' recommendations and their estimates of our financial performance;
- public reaction to our press releases, announcements and filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and natural gas companies;
- variations in the amount of our quarterly cash distributions to our unitholders;
- changes in tax law;
- an election by our general partner to convert or restructure us as a taxable entity;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements that apply to other public companies, including those relating to auditing standards and disclosure about our executive compensation.

The JOBS Act contains provisions that, among other things, relax certain reporting requirements for "emerging growth companies," including certain requirements relating to auditing standards and compensation disclosure. We are classified as an emerging growth company. For as long as we are an emerging growth company, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley

Act of 2002, (2) comply with any new requirements adopted by the Public Company Accounting Oversight Board ("PCAOB") requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer,

(3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise or (4) provide certain disclosure regarding executive compensation required of larger public companies.

Taking advantage of the longer phase-in periods for the adoption of new or revised financial accounting standards applicable to emerging growth companies may make our common units less attractive to investors.

We have elected to take advantage of all of the reduced reporting requirements and exemptions available to emerging growth companies under the JOBS Act, including the longer phase-in periods for the adoption of new or revised financial accounting standards under Section 107 of the JOBS Act, until we are no longer an emerging growth company. If we were to subsequently elect instead to comply with these public company effective dates, such election would be irrevocable pursuant to Section 107 of the JOBS Act.

Our election to use the phase-in periods permitted by this election may make it difficult to compare our financial statements to those of non-emerging growth companies and other emerging growth companies that have opted out of the longer phase-in periods under Section 107 of the JOBS Act and who will comply with new or revised financial accounting standards. We cannot predict if investors will find our common units less attractive because we elected to rely on these exemptions. If some investors find our common units less attractive as a result, there may be a less active trading market for our common units and our common unit price may be more volatile. Under the JOBS Act, emerging growth companies can delay adopting new or revised accounting standards until such time as those standards apply to private companies.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent.

Under our partnership agreement, our general partner may, without unitholder approval, cause us to be treated as an entity taxable as a corporation or subject to entity-level taxation for U.S. federal income tax purposes, whether by election of the partnership or conversion of the partnership or by any other means or methods. In addition and as part of such determination, affiliates of our general partner may choose to retain their partnership interests in us and cause us to enter into a transaction in which our interests held by other persons are converted into or exchanged for interests in a new entity, taxable as a corporation or subject to entity-level taxation for U.S. federal purposes, whose sole assets are interests in us. The general partner may take any of the foregoing actions if it in good faith determines (meaning it subjectively believes) that such action is not adverse to our best interests. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may be material to such unitholder and may vary depending on the unitholder’s particular situation and may vary from the tax liability of us or of any affiliates of our general partner who choose to retain their partnership interests in us. Our general partner will have no duty or obligation to make any such determination or take any such actions, however, and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in a manner not adverse to the best interests of us or our limited partners.

We incur increased costs as a result of being a publicly traded partnership.

We have a limited history operating as a publicly traded partnership. As a publicly traded partnership, we incur significant legal, accounting and other expenses that we did not incur prior to our initial public offering. In addition, the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the NYSE, require publicly traded entities to adopt various corporate governance practices that will further increase our costs. The amount of our expenses or reserves for expenses, including the costs of being a publicly traded partnership reduce the amount of cash we have for distribution to our unitholders. As a result, the amount of cash we have available for distribution to our unitholders is affected by the costs associated with being a public company.

As a result of our initial public offering, we became subject to the public reporting requirements of the Exchange Act. These rules and regulations has increased certain of our legal and financial compliance costs and made certain activities more time-consuming and costly. For example, as a result of becoming a publicly traded company, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting.

We also incur additional expense in order to obtain director and officer liability insurance. Because of the limitations in coverage for directors, it may be more difficult for us to attract and retain qualified persons to serve on the Board or as executive officers than it was prior to our initial public offering.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our units or if our operating results do not meet their expectations, our unit price could decline.

The trading market for our common units is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our unit price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common units or if our operating results do not meet their expectations, our unit price could decline.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (the "IRS") were to treat us as a corporation for federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our classification as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate and we would also likely pay additional state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders could be reduced. Thus, treatment of us as a corporation could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common 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, capital, and other forms of business taxes, as well as subjecting nonresident partners to taxation through the imposition of withholding obligations and composite, combined, group, block, or similar filing obligations on nonresident partners receiving a distributive share of state "sourced" income. We currently own property or do business in New Mexico, Texas and Colorado, among other states. Imposition on us of any of these taxes in jurisdictions in which we own assets or conduct business or an increase in the existing tax rates could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation. From time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships or an investment in our common units, including elimination of partnership tax treatment for certain publicly traded partnerships.

Any changes to federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to be treated as a partnership for federal income tax purposes or otherwise adversely affect our business, financial condition or results of operations. Any such changes or interpretations thereof could adversely impact the value of an investment in our common units.

Certain U.S. federal income tax incentives currently available with respect to oil and natural gas exploration and production may be reduced or eliminated as a result of future legislation.

In recent years, legislation has been proposed that would, if enacted, make significant changes to United States tax laws, including the reduction or elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We will generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units and the cost of any IRS contest will reduce our cash available for distribution to unitholders.

The IRS has made no determination as to our status as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, our costs of any contest with the IRS, principally legal, accounting and related fees, will be indirectly borne by our unitholders because the costs will reduce our cash available for distribution.

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, in which case we would pay the taxes directly to the

IRS. If we bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, 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. Our general partner would cause us to pay the taxes (including any applicable penalties and interest) directly to the IRS. 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 common 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.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount from the cash that we distribute, our unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gains or losses on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder’s allocable share of our net taxable income decrease the unitholder’s tax basis in the unitholder’s common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than the unitholder’s tax basis in those common units, even if the price received is less than the unitholder’s original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items such as depreciation, depletion, amortization and IDCs. In addition, because the amount realized may include a unitholder’s share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

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

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business (“business interest”) may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

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

Investments in our common units by tax-exempt entities, such as individual retirement accounts (“IRAs”) or other retirement plans, and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. A tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor regarding the impact of these rules on an investment in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

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

Moreover, upon the sale, exchange or other disposition of a common unit by a non-U.S. unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. The U.S. Department of the Treasury and the IRS have issued final regulations providing guidance on the application of these rules for transfers of certain publicly traded partnership interests, including transfers of our common units. Under these regulations, the “amount realized” on a transfer of our common units will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and such broker will generally be responsible for the relevant withholding obligations. Distributions to non-U.S. unitholders may also be subject to additional withholding under these rules to the extent a portion of a distribution is attributable to an amount in excess of our cumulative net income that has not previously been distributed. The U.S. Department of the Treasury and the IRS have provided that these rules will generally not apply to transfers of our common units occurring before January 1, 2023. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

We will treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation, depletion and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder’s tax returns.

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes imposed by the various jurisdictions in which we do business or own property now or in the future, even if the unitholder does not live in any of those jurisdictions. Our common 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, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in New Mexico, Texas and Colorado, among other states. New Mexico and Colorado each impose a personal income tax. Texas does not currently impose a personal income tax on individuals, but it does impose an entity level tax (to which we will be subject) on corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. It is the responsibility of each unitholder to file its own federal, state and local tax returns, as applicable.

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

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have 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 common units during the period of the loan and the unitholder 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 common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common 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 lending their common units.

We will adopt certain valuation methodologies in determining a 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.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but management believes it is remote that pending or threatened legal matters will have a material adverse impact on our financial condition. Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment-related disputes. In the opinion of our management, none of these other pending litigation matters, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

Item 4. Mine Safety Disclosures

None.

Part II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Market Information, Holders and Distributions

Our common units are listed and traded on the New York Stock Exchange under the symbol "TXO." As of March 28, 2023, there were 2 record holders. Our common units began publicly trading on the NYSE on January 27, 2023. Prior to that time, there was no public market for our common units.

Since the closing of our initial public offering on January 31, 2023, no distributions have been made. Our partnership agreement requires us to distribute all of our available cash within 60 days following the end of each quarter (other than the fourth quarter of each fiscal year), and within 90 days following the end of the fourth quarter of each fiscal year, beginning with the quarter ending March 31, 2023. See the "Cash Distribution Policy" section below for a discussion of our policy regarding distribution payments.

Recent Sales of Unregistered Securities

None other than as previously reported in our Current Report on Form 8-K filed with the SEC on January 31, 2023.

Use of Proceeds

On January 31, 2023, we completed the initial public offering of our common units pursuant to which we issued and sold 5,000,000 shares of our common units at a price to the public of $20.00 per unit. In addition, on February 6, 2023, we sold an additional 750,000 common units pursuant to the underwriter's option to purchase additional units to cover over-allotments. All of the common units issued and sold in our initial public offering were registered under the Securities Act pursuant to a registration statement on Form S-1 (File No. 333-268424), which was declared effective by the SEC on January 26, 2023. We received net proceeds of approximately $102.0 million, after deducting underwriting discounts and commissions and offering expenses borne by us. None of the expenses incurred by us were direct or indirect payments to any of (i) our directors or officers or their associates, (ii) persons owning 10% or more of our common stock, or (iii) our affiliates. There has been no material change in the planned use of proceeds from our initial public offering to repay a portion of the amounts outstanding under our Credit Facility as described in our final prospectus filed with the SEC on January 27, 2023 pursuant to Rule 424(b)(4).

Issuer Purchases of Equity Securities

None.

Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash each quarter. Our cash distribution policy reflects a basic judgment that our unitholders generally will be better served by us distributing our available cash, after expenses and reserves, rather than retaining it. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions from our available cash in the aforementioned or any other amount, and our general partner has considerable discretion to determine the amount of cash available for distribution each quarter.

Because our policy will be to distribute all available cash we generate each quarter, without reserving cash for future distributions or borrowing to pay distributions during periods of low revenue, our unitholders will have direct exposure to fluctuations in the amount of cash generated by our business. Our quarterly cash distributions from our available cash, if any, will not be stable and will vary from quarter to quarter as a direct result of variations in the performance of our operators and revenue caused by fluctuations in the prices of oil and natural gas. Such variations may be significant.

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

less, the amount of cash reserves established by our general partner to:

- provide for the proper conduct of our business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;

- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders for any one or more of the next four quarters;

plus, all cash on hand on the date of determination resulting from dividends or distributions received after the end of the quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter;

plus, if our general partner so determines, all or a portion of cash on hand on the date of determination resulting from working capital borrowings made after the end of the quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than additional working capital borrowings.

Item 6. [Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our audited financial statements as of and for the years ended December 31, 2022 and 2021 and related notes thereto, included in Item 8. Financial Statements. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. These forward-looking statements are dependent upon events, risks and uncertainties that may be outside of our control. Our actual results could differ materially from those disclosed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in "Risk Factors" and "Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

We have applied provisions of the SEC's FAST Act Modernization and Simplification of Regulation S-K, which limits the discussion to the two most recent fiscal years. This discussion and analysis deals with comparisons of material changes in the consolidated financial statements for the years ended December 31, 2022 and 2021. For the comparison of the years ended December 31, 2021 and 2020, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Registration Statement which was declared effective by the SEC on January 26, 2023, as amended.

Unless otherwise indicated, throughout this discussion the term "MBoe" refers to thousands of barrels of oil equivalent quantities produced for the indicated period, with natural gas and NGL quantities converted to Bbl on an energy equivalent ratio of six Mcf to one barrel of oil.

Overview

We are an independent oil and natural gas company focused on the acquisition, development, optimization and exploitation of conventional oil, natural gas and natural gas liquid reserves in North America. Our properties are predominately located in the Permian Basin of New Mexico and Texas and the San Juan Basin of New Mexico and Colorado.

Initial Public Offering

On January 31, 2023, we completed our initial public offering in which we issued and sold 5,000,000 common units at a public offering price of $20.00 per unit. In addition, on February 6, 2023, we sold an additional 750,000 common units pursuant to the underwriter's option to purchase additional units to cover over-allotments. We received net proceeds of approximately $102.0 million, after deducting underwriting discounts and commissions and offering expenses borne by us. We utilized the proceeds from our initial public offering and cash on hand to pay down our credit facility in full as of March 31, 2023.

For additional information, see Note 1 to our audited consolidated financial statements in this Annual Report on Form 10-K.

Market Outlook

The oil and natural gas industry is cyclical and commodity prices are highly volatile. For example, during the period from January 1, 2021 through December 31, 2022, prices for crude oil and natural gas reached a high of $123.70 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.62 per Bbl and $2.43 per MMBtu, respectively. Oil prices steadily increased through 2021 due to continued recovery in demand before increasing drastically in the first half of 2022 due to further demand, domestic supply reductions, OPEC control measures and market disruptions resulting from the Russia-Ukraine war and sanctions on Russia. Since the Russia-Ukraine conflict first commenced, WTI crude oil prices have been volatile, rising from $92.81 per Bbl on February 24, 2022 to a high of $123.70 per Bbl in March 2022 before declining to $77.05 per Bbl as of February 28, 2023. Natural gas prices reached a high of $9.85 per MMbtu in August 2022 before declining to $2.50 per MMbtu as of February 28, 2023. These prices have been very volatile and experience large swings, sometimes on a day-to-day or week-to-week basis.

We expect the crude oil and natural gas markets will continue to be volatile in the future. Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Please see “Risk Factors—Risks Related to the Natural Gas, NGL and Oil Industry and Our Business—Commodity prices are volatile—A sustained decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.”

With our anticipated cash flows from our long-lived property base, we intend to provide dynamic allocation of funds to prudently meet our goals. These goals include the highest projected economic returns on our capital budget, acquisition opportunities that fulfill our strategy, and cash distributions for the life of our legacy assets. From time to time, we may choose to amortize the repayment of debt incurred in modest acquisitions to support the longer-term financial stewardship of our business. At other times, given fluctuations in industry costs and commodity prices, we may modify our capital budget or cash balances to shift funds towards cash distributions. We will use all of these tools to support our underlying strategy as a “production and distribution” enterprise.

Although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which has continued into 2022, due to a substantial increase in the money supply, a stimulative fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 5.4% in June 2021 to as high as 9.1% in June 2022 but has recently trended down to 6.0% in February 2023. Global, industry-wide supply chain disruptions have resulted in widespread shortages of labor, materials and services. Such shortages have resulted in our facing significant cost increases for labor, materials and services. Principally, commodity costs for steel and chemicals required for drilling, higher transportation and fuel costs and annual wage increases have increased our operating costs in the year ended December 31, 2022 compared to 2021. We also may face shortages of these commodities and labor, which may prevent us from executing on our development plan. While prices appear to have begun moderating, we do not expect these shortages and cost increases to reverse in the short term. Typically, as prices for oil and natural gas increase, so do associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion to prices. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience further cost increases in our operations, including costs for drill rigs, workover rigs, tubulars and other well equipment, as well as increased labor costs. If we are unable to recover higher costs through higher commodity prices, our current revenue stream, estimates of future reserves, borrowing base calculations, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions would all be significantly impacted.

We are taking actions to mitigate supply chain and inflationary pressures. We pre-purchased pipe necessary to drill the remainder of our planned development for 2022 and we are looking at whether to do the same in the first half of 2023. We are working closely with other suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical supplies which are critical to many of our operations. However, these mitigation efforts may not succeed or be insufficient.

Sources of Our Revenue

Our revenues are derived from the sale of our oil, NGLs and natural gas production. Our revenues are influenced by production volumes and realized prices on the sale of oil, NGLs, and natural gas including the effect of our commodity derivative contracts. We sell oil, natural gas and NGLs at a specific delivery point, pay transportation to third parties and receive proceeds from the purchaser with no transportation deduction. As a result, we record transportation costs we pay to third parties as taxes, transportation and other deductions. Pricing of commodities is subject to supply and demand as well as to seasonal, political and other conditions that we generally cannot control. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. The following table presents the breakdown of our revenues including both the realized and unrealized effects of our commodity derivative contracts for the periods specified below:

	For the Year Ended December 31,	
	2022	**2021**
Crude oil sales	65 %	31 %
Natural gas sales	18 %	57 %
Natural gas liquid sales	17 %	12 %

The following table presents that breakdown of our revenues for the periods specified below excluding the unrealized effects of our commodity derivative contracts.

	For the Year Ended December 31,	
	2022	**2021**
Crude oil sales	48 %	32 %
Natural gas sales	40 %	56 %
Natural gas liquid sales	12 %	12 %

Revenue excluding the unrealized effects of commodity derivative contracts is a non-GAAP supplemental financial measure that management and external users of our combined financial statements, such as investors, lenders and others (including industry analysts and rating agencies who will be using such measure), may use for the periods presented to more effectively evaluate our operating performance and our results of operation from period to period without giving effect to non-cash gains and losses. The GAAP measures most directly comparable to revenue excluding the unrealized effects of commodity derivative contracts is GAAP revenue. You should not consider revenue excluding the unrealized effects of commodity derivative contracts in isolation or as a substitute for analysis of our results as reported under GAAP.

Production volumes

Our ability to generate sufficient cash from operations to pay cash distributions to unitholders is a function of two primary variables: (i) production volumes and (ii) commodity prices. Production volumes directly impact our revenue. Any negative effect on production volumes could have a material adverse effect on our business, financial condition, results of operations and cash available for distribution. The following table presents historical production volumes for our properties for the periods specified below:

The following table presents historical production volumes for our properties for the periods specified below:

	For the Year Ended December 31,	
	2022	2021
Oil and condensate (MBbls)	2,206	1,033
Natural gas liquids (MBbls)	1,334	1,089
Natural gas (MMcf)	29,557	30,590
Total (MBoe)	8,466	7,220
Average net sales (MBoe/day)	23	20

Sales volumes directly impact our results of operations. For more information about sales volumes, see "—Historical Results of Operations."

As reservoir pressures decline, production from a given well or formation decreases. Maintaining or growing our future production and reserves will depend on our ability to continue to replace current production with new reserves. Accordingly, we plan to focus on maintaining reserves through both the drill bit and acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel, and successfully identify and consummate acquisitions. See "Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry" for a discussion of these and other risks affecting our proved reserves and production.

Realized commodity prices

Our results of operations depend on many factors, particularly the price of our commodity production and our ability to market our production effectively. Oil and natural gas prices have historically been volatile. During the period from January 1, 2021 through December 31, 2022, prices for crude oil and natural gas reached a high of $123.70 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.62 per Bbl and $2.43 per MMBtu, respectively. A future decline in commodity prices may adversely affect our business, financial condition or results of operations. Lower commodity prices may not only decrease our revenues, but also the amount of oil and natural gas that we can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our Credit Facility, which is redetermined semi-annually. See "—Liquidity and Capital Resources—Revolving credit agreement."

The NYMEX WTI, for oil prices, and NYMEX Henry Hub, for gas prices, are widely used benchmarks for the pricing of oil and natural gas in the United States. The price we receive for our oil and natural gas production is generally different than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors.

As such, our revenues are sensitive to the price of the underlying commodity to which they relate. The following is a comparison of average pricing excluding and including the effects of derivatives:

	For the Year Ended December 31,	
	2022	2021
Average prices:		
Oil (Bbl)		
Average NYMEX Price	$ 94.33	$ 68.11
Average Realized Price (excluding derivatives)	$ 93.69	$ 67.41
Average Realized Price (including derivatives)	$ 72.93	$ 67.74
Differential to NYMEX	$ (0.64)	$ (0.70)
Natural Gas (Mcf)		
Average NYMEX Price	$ 6.54	$ 3.71
Average Realized Price (excluding derivatives)	$ 6.62	$ 4.00
Average Realized Price (including derivatives)	$ 1.48	$ 4.27
Differential to NYMEX	$ 0.08	$ 0.29
Natural gas liquids (Bbl)		
Average Realized Price (excluding derivatives)	$ 35.47	$ 25.16
Average Realized Price (including derivatives)	$ 31.28	$ 25.60
High and low NYMEX prices:		
Oil (Bbl)		
High	$ 123.70	$ 84.65
Low	$ 71.02	$ 47.62
Natural gas (MMBtu)		
High	$ 9.85	$ 23.86
Low	$ 3.52	$ 2.43

Hedging activities

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our production. In most of our current positions, our hedging activity may also reduce our ability to benefit from increases in commodity prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices, and conversely, we will recognize gains to the extent our derivatives contract prices are higher than market prices. Our policy is to opportunistically hedge a portion of our production at commodity prices management deems attractive. We are also subject to certain hedging requirements pursuant to our Credit Facility. See "—Liquidity and Capital Resources—Revolving credit agreement." While there is a risk we may not be able to realize the full benefits of rising prices, management may continue its hedging strategy because of the benefits of predictable, stable cash flows. See "—Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

The price we receive for our oil and natural gas production is generally less than the NYMEX prices because of adjustments for basis, relative quality and other factors. We have entered into basis swap agreements that effectively fix the basis adjustment for our delivery locations.

In the year ended December 31, 2022, all of our hedging activities decreased oil revenue $45.8 million, decreased NGL revenue $5.6 million and decreased gas revenue $151.8 million. In the year ended December 31, 2021, all of our hedging activities increased oil revenue $0.3 million, NGL revenue $0.5 million and gas revenue $8.2 million.

The following tables summarize our open oil, NGL and natural gas hedging production as of December 31, 2022. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl
January 2023—December 2023	2,500	$ 68.87
January 2024—June 2024	2,000	$ 63.27

Crude Oil Basis Swaps—West Texas Midland Production Period	Bbls per Day	Weighted Average Sell Basis Price per Bbl (a)
January 2023—December 2023	5,000	$ 1.21

(a) Increases to NYMEX oil price for delivery location

Crude Oil—Roll Component Production Period	Bbls per Day	Weighted Average Roll Price per Bbl (a)
January 2023—December 2023	3,000	$ 0.89

(a) Increases to NYMEX oil price for roll component

Natural Gas Liquids—Swaps Production Period	Gallons per Day	Weighted Average NGL OPIS Price per Gallon
Ethane		
January 2023—December 2023	63,000	$ 0.27
January 2024—June 2024	63,000	$ 0.23

Natural Gas—Swaps Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu
January 2023—December 2023	35,000	$ 3.51
January 2024—June 2024	30,000	$ 3.26

Natural Gas—Collars Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu	
		Floor	Ceiling
January 2023—March 2023	5,000	$ 5.00	$ 9.85
January 2024—June 2024	5,000	$ 3.75	$ 7.25

Natural Gas Basis Swaps—San Juan Production Period	MMBtu per Day	Weighted Average Sell Basis Price per MMBTU (a)
January 2023—December 2023	70,000	$ 0.17

(a) Reductions to NYMEX gas price for delivery location

Principal Components of Our Cost Structure

Production expenses

Production expenses are the costs incurred in the operation of producing properties and include workover costs. Expenses for labor, overhead and repairs and maintenance comprise the most significant components of production expenses. Lease operating expenses do not include general and administrative expenses or severance or ad valorem taxes. We evaluate production expenses on a per Boe basis to monitor changes in production expenses to determine that costs are at an acceptable level. We monitor our operations to ensure that we are incurring lease operating expenses at an acceptable level. Although we strive to reduce our lease operating expenses, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate and develop our properties or make acquisitions of properties.

Taxes, transportation, and other expenses

Taxes, transportation, and other expenses consist primarily of gathering and processing fees, transportation costs, severance taxes, and ad valorem taxes. Gathering, processing and transportation costs are recognized when control of the natural gas we sell occurs at the tailgate of the processing plant. Severance taxes are paid on produced oil and natural gas based on a percentage of net revenues from production sold at fixed rates established by state or local taxing authorities. In general, the severance taxes we pay correlate to the changes in oil and natural gas revenues. We are also subject to ad valorem taxes in the counties where our production is located. We evaluate taxes, transportation, and other expense on a per Boe basis to monitor costs to ensure that they are at acceptable levels. Taxes, transportation, and other expenses can also be influenced by acquisitions, commodity prices, changes in values of our properties, sales mix and acquisitions.

Depletion, depreciation, and amortization

Depreciation, depletion, and amortization (“DD&A”) is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. We follow the successful efforts method of accounting, capitalizing costs of successful acquisitions and exploratory wells, which are then allocated to each unit of production using the unit of production method, and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. Changes in DD&A are a result of production and changes in the estimated reserves during the period.

General and administrative expenses

General and administrative expenses consist primarily of personnel related costs and are partially offset by certain reimbursements of overhead expenses. However, we do not expect to experience a material change in our cash cost structure, other than as set forth below under “Factors Affecting the Comparability of Our Financial Condition and Results of Operations.”

Interest expense

Interest expense is primarily a result of interest on our borrowings on our Credit Facility to fund operations and acquisitions of properties as well as the amortization of debt issuance costs associated with these borrowings. Interest expense can fluctuate with our level of indebtedness as well as changes in interest rates.

Income tax

Texas does not currently impose a personal income tax on individuals, but it does impose an entity level tax (to which we will be subject) on corporations and other entities. While we do not pay income tax in Texas, we are subject to Texas franchise taxes.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our operations, including:

- production volumes;

- realized prices on the sale of oil, NGLs and natural gas;
- production expenses;
- acquisition and development expenditures
- Adjusted EBITDAX; and
- Cash Available for Distribution.

Adjusted EBITDAX

We define Adjusted EBITDAX as net income (loss) before (1) interest income, (2) interest expense, (3) depreciation, depletion and amortization, (4) impairment expenses, (5) accretion of discount on asset retirement obligations, (6) exploration expenses, (7) unrealized (gain) losses on commodity derivative contracts, (8) non-cash incentive compensation, (9) non-cash (gain) loss on forgiveness of debt and (10) certain other non-cash expenses.

Adjusted EBITDAX is not a measure of net income as determined by U.S. GAAP. Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate the financial performance of our assets from period to period and against our peers without regard to financing methods or capital structure.

Cash Available for Distribution

Although we have not quantified cash available for distribution on a historical basis, we intend to use cash available for distribution to assess our ability to internally fund our exploration and development activities, pay distributions, and to service or incur additional debt. We define cash available for distribution as Adjusted EBITDAX less cash interest expense, exploration expense and development costs. Development costs include all of our capital expenditures made for oil and gas properties, other than acquisitions. Cash available for distribution will not reflect changes in working capital balances.

You should not infer from our presentation of Adjusted EBITDAX that its results will be unaffected by unusual or non-recurring items. You should not consider Adjusted EBITDAX or cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because Adjusted EBITDAX and cash available for distribution may be defined differently by other companies in our industry, our definition of Adjusted EBITDAX and cash available for distribution may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Results of Operations

Year Ended December 31, 2022 Compared to the Year Ended December 31, 2021

	December 31,	
	2022	2021
	(in thousands)	
Revenues:		
Oil and condensate sales	$ 160,864	$ 69,971
Natural gas liquids sales	$ 41,731	$ 27,875
Gas sales	$ 43,802	$ 130,498
Total revenues	$ 246,397	$ 228,344
Expenses:		
Production expenses	$ 127,661	$ 69,256
Exploration expenses	$ 360	$ 124
Taxes, transportation, and other	$ 94,991	$ 58,040
Depreciation, depletion, and amortization	$ 41,364	$ 39,889
Accretion of discount in asset retirement obligations	$ 6,055	$ 4,670
General and administrative	$ 1,646	$ 12,175
Total expenses	$ 272,077	$ 184,154
Operating (loss) income	$ (25,680)	$ 44,190
Other income (expense):		
Other income	$ 26,067	$ 14,139
Interest income	$ 143	$ 16
Interest expense	$ (8,198)	$ (5,870)
Total other income	$ 18,012	$ 8,285
Net (loss) income	$ (7,668)	$ 52,475

The following table provides a summary of our sales volumes, average prices (both including and excluding the effects of derivatives) and operating expenses on a per Boe basis for the periods indicated:

	December 31,			
	2022		2021	
Sales:				
Oil and condensate sales (MBbls)		2,206		1,033
Natural gas liquids sales (MBbls)		1,334		1,089
Natural gas sales (MMcf)		29,557		30,590
Total (MBoe)		8,466		7,220
Total (MBoe/d)		23		20
Average sales prices:				
Oil and condensate excluding the effects of derivatives (per Bbl)	$	93.69	$	67.41
Oil and condensate (per Bbl) (1)	$	72.93	$	67.74
Natural gas liquids excluding the effects of derivatives (per Bbl)	$	35.47	$	25.16
Natural gas liquids (per Bbl) (2)	$	31.28	$	25.60
Natural gas excluding the effects of derivatives (per Mcf)	$	6.62	$	4.00
Natural gas (per Mcf) (3)	$	1.48	$	4.27
Expense per Boe:				
Production	$	15.08	$	9.59
Taxes, transportation and other	$	11.22	$	8.04
Depreciation, depletion and amortization	$	4.89	$	5.52
General and administrative expenses	$	0.19	$	1.69

(1) Oil and condensate prices include both realized and unrealized losses from derivatives. The unrealized losses were $13.0 million for the year ended December 31, 2022 and unrealized gains were $0.3 million for the year ended December 31, 2021. The realized losses were $32.8 million for the year ended December 31, 2022 and $0.0 million for the year ended December 31, 2021.

(2) Natural gas liquids prices include both realized and unrealized losses from derivatives. The unrealized losses were $1.0 million for the year ended December 31, 2022 and unrealized gains were $0.5 million for the year ended December 31, 2021. The realized losses were $4.6 million for the year ended December 31, 2022 and $0.0 million for the year ended December 31, 2021.

(3) Natural gas prices include both realized and unrealized losses from derivatives. The unrealized losses were $99.2 million for the year ended December 31, 2022 and unrealized gains were $8.2 million for the year ended December 31, 2021. The realized losses were $52.6 million for the year ended December 31, 2022 and $0.0 million for the year ended December 31, 2021.

Revenues

Revenues increased $18.1 million, or 8%, from $228.3 million for the year ended December 31, 2021 to $246.4 million for the year ended December 31, 2022. The increase was primarily attributable to an increase in production of 1,246 MBoe primarily as a result of additional production from the acquired Vacuum properties of 1,169 MBoe and Andrews Parker properties of 326 Mboe, respectively, partially offset by decreased historical production of 248 MBoe resulting in an increase in revenue of $111.8 million and an increase in the average selling price, excluding the effects of derivatives, on oil of 39% resulting in an increase in revenue of $27.2 million, on NGLs of 41% resulting in an increase in revenue of $11.2 million, and on natural gas of 65% resulting in an increase in revenue of $80.1 million. These increases were partially offset by losses on our hedging activity of $212.2 million, of which $122.2 million were unrealized losses and $90.0 million were realized losses.

Production expenses

Production expenses increased $58.4 million, or 84%, from $69.3 million for the year ended December 31, 2021 to $127.7 million for the year ended December 31, 2022. The increase is primarily attributable to the increased production associated with the addition of the Vacuum and Andrews Parker properties of $51.7 million as well as increased maintenance costs and other cost increases.

On a per unit basis, production expenses increased from $9.59 per Boe sold for the year ended December 31, 2021 to $15.08 per Boe sold for the year ended December 31, 2022. The increase is primarily related to the increased costs per Boe from the acquired Vacuum and Andrews Parker properties due to the acquired properties having a higher percentage of oil production, which is more expensive on a Boe basis than natural gas production. Additionally, increased maintenance costs and other cost increases contributed to the increase per Boe.

Taxes, transportation, and other

Taxes, transportation, and other increased $37.0 million, or 64%, from $58.0 million for the year ended December 31, 2021 to $95.0 million for the year ended December 31, 2022. The increase is primarily attributable to the increased production associated with the addition of the Vacuum and Andrews Parker properties of $18.7 million as well as an increase in oil, NGLs, and natural gas prices.

On a per unit basis, taxes, transportation, and other increased from $8.04 per Boe sold for the year ended December 31, 2021 to $11.22 per Boe sold for the year ended December 31, 2022. The increase is primarily related to the higher commodity prices and change in production mix.

Depreciation, depletion, and amortization

Depreciation, depletion, and amortization increased $1.5 million, or 4%, from $39.9 million for the year ended December 31, 2021 to $41.4 million for the year ended December 31, 2022. The increase is primarily attributable to the increased production associated with the addition of the Vacuum and Andrews Parker properties in the fourth quarter of 2021 of $12.3 million partially offset by a reduction of $10.8 million from our other assets as a result of a lower average DD&A rate and decreased production.

On a per unit basis, depreciation, depletion, and amortization decreased from $5.52 per Boe sold for the year ended December 31, 2021 to $4.89 per Boe sold for the year ended December 31, 2022. The decrease is primarily related to changes in reserves.

General and administrative

General and administrative (“G&A”) expenses decreased $10.5 million, or 86%, from $12.2 million for the year ended December 31, 2021 to $1.6 million for the year ended December 31, 2022. The decrease is primarily attributable to a reduction of $5.2 million from headcount reductions, $3.0 million related to losses and write-offs from the Southland bankruptcy in 2021 and $2.4 million of non-cash incentive compensation in 2021.

On a per unit basis, G&A expense decreased from $1.69 per Boe sold for the year ended December 31, 2021 to $0.19 per Boe sold for the year ended December 31, 2022. The decrease is primarily related to decreased costs and increased production.

Other income

Other income increased $11.9 million, or 84%, from $14.1 million for the year ended December 31, 2021 to $26.1 million for the year ended December 31, 2022. The increase is primarily attributable to the recognition of $23.7 million of CO_2 and plant income related to the acquired Vacuum properties partially offset by the absence of the forgiveness of debt of $9.2 million under the U.S. Government’s Paycheck Protection Program from the Small Business Administration and the absence of the $3.6 million gain on sale of properties. The CO_2 and plant income is ancillary to the operations of the Vacuum properties.

Interest expense

Interest expense increased $2.3 million, or 40%, from $5.9 million for the year ended December 31, 2021 to $8.2 million for the year ended December 31, 2022. The increase is primarily attributable to the additional borrowings to fund the Chevron Acquisitions, the Additional Interest Vacuum Acquisition and a higher interest rate.

Liquidity and Capital Resources

Our primary sources of liquidity and capital are cash flows generated by operating activities and borrowings under our Credit Facility. Outstanding borrowings under our Credit Facility were $145.0 million at December 31, 2021 and $113.0 million at December 31, 2022, and the remaining availability under our Credit Facility was $20.0 million at December 31, 2021 and $52.0 million at December 31, 2022. Additionally, we had positive net working capital (including

cash and excluding the effects of derivative instruments) of $17.6 million at December 31, 2021 and $20.7 million at December 31, 2022. After the close of our initial public offering in February 2023, we utilized the proceeds and cash on hand to pay down our credit facility, so that we had no debt outstanding and $165.0 million available under our Credit Facility (based on the borrowing base as of December 31, 2022) as of March 31, 2023.

As a publicly traded partnership, our primary sources of liquidity and capital resources are from cash flow generated by operating activities and borrowings under our Credit Facility. Historically, our primary sources of liquidity have also included capital contributions by our equity holders, but we do not expect to rely on management or our partners for capital going forward. We may need to utilize the public equity or debt markets and bank financings to fund future acquisitions or capital expenditures, but the price at which our common units will trade could be diminished as a result of the limited voting rights of unitholders. We expect to be able to issue additional equity and debt securities from time to time as market conditions allow to facilitate future acquisitions. We expect to repay any debt incurred by us to complete such acquisitions in order to meet our long-term goal of remaining substantially debt free. Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations or to refinance our indebtedness will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory, weather and other factors.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to our unitholders. Our quarterly cash distributions may vary from quarter to quarter as a direct result of variations in the performance of our business, including those caused by fluctuations in the prices of oil and natural gas. Such variations may be significant and quarterly distributions paid to our unitholders may be zero. The first distribution will be paid in May 2023 with respect to cash available for distribution for the quarter ending March 31, 2023.

In addition, our partnership agreement permits us to borrow funds to make distributions to our unitholders. We may, but are under no obligation to, borrow to make distributions to our unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long-term, but short-term factors have caused available cash from operations to be insufficient to sustain our level of distributions. For example, we generally intend to hedge a portion of our production. We generally will be required to settle our commodity hedge derivatives within twenty-five days of the end of the month. As is typical in the oil and gas industry, we do not generally receive the proceeds from the sale of our hedged production until 20 to 60 days following the end of the month. As a result, when commodity prices increase above the fixed price in the derivative contracts, we will be required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before we receive the proceeds from the sale of the hedged production. If this occurs, we may borrow to fund our distributions.

Our acquisition and development expenditures consist of acquisitions of proved, unproved and other property and development expenditures. Our capital expenditures including acquisitions were $86.7 million for the year ended December 31, 2022 and $227.8 million for the year ended December 31, 2021.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. We were required under our Credit Facility to hedge at least 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022, and at least 50% for the period from month 13 to month 30. However, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and liquidity under the Credit Facility is equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month twenty-four will be reduced to 50% and the requirement to maintain the minimum required hedge volume for months 25 through 30 shall be removed. Our Credit Facility prohibits us from hedging more than 90% of our reasonably projected production for any fiscal year. From September 30, 2022 through the next scheduled spring redetermination which shall occur no later than June 30, 2023, we received waivers to reduce the hedging requirement from 30 months to 15 months and from 50% to 45% of the reasonably anticipated projected production. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement” for more information. Our policy is to consider hedging a portion of our production at commodity prices management deems attractive.

We incurred costs of approximately $29.8 million for drilling, completion and recompletion activities and facilities costs in 2022 and we have budgeted approximately $30.0 - $35.0 million for such costs in 2023. We expect to fund these capital expenditures from cash flow from operations.

The amount and timing of these capital expenditures is substantially within our control and subject to management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to the prevailing and anticipated prices for oil, NGLs and natural gas, the availability of necessary equipment, infrastructure and capital, seasonal conditions and drilling and acquisition costs. Any postponement or elimination of our development program could result in a reduction of proved reserve volumes, production and cash flow, including distributions to unitholders.

Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our distributions, meet our debt obligations and fund our 2023 capital development programs from the proceeds from the our initial public offering and cash flow from operations.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures and/or distributions to unitholders. Alternatively, we may fund these expenditures using borrowings under our Credit Facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us, finance the capital expenditures necessary to maintain our production or proved reserves, or make distributions to unitholders.

Cash flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	For the Year Ended December 31,	
	2022	**2021**
Net cash provided by operating activities	$ 136,380	$ 73,726
Net cash used by investing activities	(86,670)	(227,801)
Net cash provided by (used in) financing activities	(48,053)	139,689

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Net cash provided by operating activities

Net cash provided by operating activities increased $62.7 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily as a result of improved prices in 2022 compared to 2021 and increased production primarily due to the Vacuum and Andrews acquisitions in late 2021 partially offset by increased costs.

Net cash used by investing activities

Net cash used by investing activities decreased $141.1 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 due to a decrease in proved property and other property acquisitions of $156.1 million and proceeds from sale of property of $0.3 million partially offset by an increase in development costs of $15.3 million.

Net cash (used by) provided by financing activities

	For the Year Ended December 31,	
	2022	2021
	(in thousands)	
Proceeds from long-term debt	$ 1,461,000	$ 1,437,000
Payments on long-term debt	$ (1,493,000)	$ (1,427,000)
Proceeds from partners' investment	$ —	$ 132,660
Debt issuance costs	$ (161)	$ (2,832)
Capitalized offering costs	$ (3,738)	$ —
Proceeds from exercise of Series 3 warrants	$ 1,029	$ —
Distributions	$ (13,183)	$ (139)
Net cash (used by) provided by financing activities	$ (48,053)	$ 139,689

Net cash used in financing activities increased $187.7 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 due to an absence of partners' investments of $132.7 million, an increase in net repayments under our credit facility of $42.0 million, a $13.0 million increase in distributions and an increase in capitalized offering costs of $3.7 million partially offset by decreased debt issuance costs $2.7 million and proceeds from exercise of Series 3 warrants $1.0 million.

Revolving credit agreement

On November 1, 2021, we entered into a new four-year, $165 million senior secured credit facility (the "Credit Facility") with JPMorgan Chase Bank, N.A., as administrative agent, and certain commercial banks as lenders. Our Credit Facility permits us to use proceeds for general partnership purposes including distributions to our unitholders. Our obligations under the Credit Facility are secured by substantially all of our assets, including (i) our interest in Cross Timbers, (ii) all our deposit accounts, securities accounts, and commodities accounts, (iii) any receivables owed to us by the joint venture and (iv) any oil and gas properties owned directly by us and our wholly-owned subsidiaries. The facility has a maturity date of November 1, 2025. In connection with entering into the Credit Facility, as of December 31, 2022, we incurred financing fees and expenses of approximately $2.8 million before accumulated amortization of $0.8 million. These costs are being amortized over the life of the Credit Facility. Such amortized expenses are recorded as interest expense on the statements of operations. As of December 31, 2022, we had $113 million in borrowings outstanding under our Credit Facility and $52 million in availability. We utilized the proceeds from our initial public offering and cash on hand to pay down our credit facility in full, so that we have no debt outstanding and $165.0 million available under our Credit Facility as of March 31, 2023.

Under our Credit Facility, the borrowing base is determined based on the value of our oil and natural gas properties and the oil and gas properties of our wholly owned subsidiaries. The borrowing base is subject to further adjustments for asset dispositions, material title deficiencies, certain terminations of hedge agreements and issuances of permitted additional indebtedness. As of November 3, 2022, the last date of redetermination, our borrowing base was $165 million.

Redetermination of the borrowing base under the Credit Facility is based primarily on reserve reports that reflect commodity prices at such time and occurs semi-annually, in March and September, as well as upon requested interim redeterminations by the lenders at their sole discretion. We also have the right to request additional borrowing base redeterminations each year at our discretion. Significant declines in commodity prices may result in a decrease in the borrowing base. These borrowing base declines can be offset by any commodity price hedges we enter.

Our Credit Facility contains certain customary representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on merging or consolidating with another company, limitations on making certain restricted payments, limitations on investments, limitations on paying distributions on, redeeming, or repurchasing common units, limitations on entering into transactions with affiliates, and limitations on asset sales. The Credit Facility also contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable.

At our election, interest on borrowings under the Credit Facility is determined by reference to either the secured overnight financing rate ("SOFR") plus an applicable margin between 3.00% and 4.00% per annum (depending on the then-current level of borrowings under the Credit Facility) or the alternate base rate ("ABR") plus an applicable margin between 2.00% and 3.00% per annum (depending on the then-current level of borrowings under the Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at SOFR. We are required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum of 0.5% on the average daily unused amount of the lesser of: (i) the maximum commitment amount of the lenders and (ii) the then-effective borrowing base, less the aggregate outstanding principal amount of the loans at such time. The weighted average interest rate on Credit Facility borrowings was 5.4% in 2022. The effective borrowing rate under our Credit Facility was 7.8% as of December 31, 2022.

We are required to maintain (i) a current ratio (the ratio of current assets to current liabilities) greater than 1.0 to 1.0, which for purposes of this definition includes availability under the Credit Facility but excludes the fair value of derivative instruments, and (ii) a ratio of total net debt-to-EBITDAX of not greater than 3.00 to 1.00. For purposes of the total net debt-to-EBITDAX ratio, total net debt is total debt for borrowed money (including capital leases and purchase money debt) minus the unpaid balance of the FAM Loan (as defined in Note 4), minus unrestricted cash and cash equivalents on hand at such time (not exceeding $15.0 million in the aggregate), and EBITDAX includes Cross Timber's EBITDAX only to the extent of cash distributions received by us. For purposes of our Credit Facility, EBITDAX is defined to mean net income plus interest expense; income taxes paid; depreciation, depletion and amortization; exploration expenses, including workover expenses; non-cash charges including unrealized losses on derivative instruments; and any extraordinary or non-recurring charges, minus any extraordinary or non-recurring income and any non-cash income including unrealized gains on derivative instruments. Furthermore, we only include realized hedge gains less realized hedge losses and our consolidated expenses. We were in compliance with all financial and other covenants of the Credit Facility, except the covenant regarding hedge volumes required as of September 30, 2022. We received a waiver for this exception in September 2022 (the "September 2022 Waiver"). The September 2022 Waiver, which will continue through the next scheduled redetermination in March 2023, allows us to reduce the testing period for our hedging requirement from 30 months to 18 months beginning September 30, 2022 and reduce the required minimum hedge volume for such period from 50% to 45% of the reasonably anticipated projected production. We received a new waiver in March 2023 (the "March 2023 Waiver"), which extends the term of the September 2022 Waiver. Under the March 2023 Waiver, which will continue through the next scheduled redetermination to be completed no later than June 30, 2023, the testing period for our hedging requirement was reduced an additional three months to 15 months. As a result, as of December 31, 2022, we were in compliance with all covenants in our Credit Facility as adjusted under the September 2022 Waiver. We believe that we have a sufficient combination of resources and operating flexibility to ensure that we remain in compliance with our debt covenants for at least the next 12 months.

Our Credit Facility permits us to make distributions of 100% of our "Distributable Cash Flow" so long as (i) at the time of any such distribution and immediately after giving effect thereto, no default, event of default or borrowing base deficiency has occurred and is continuing, (ii) the our ratio of total net debt-to-EBITDAX does not exceed 2.00 to 1.00 as of the last day of the fiscal quarter most recently ended for which our financial statements have been delivered (determined on a pro forma basis after giving effect to such distribution) and (iii) after giving effect to such distribution, there is at least 20% of total borrowings then available under our Credit Facility. For purposes of our Credit Facility, "Distributable Cash Flow" is defined, generally, to mean (a) our EBITDAX during each period of four consecutive quarters (a "rolling period"), minus the increase (or plus the decrease) in working capital from the previous rolling period minus (b) the sum of (i) capital expenditures paid in cash, (ii) cash interest expense, (iii) cash taxes paid, (iv) exploration expenses or costs paid in cash, (v) restricted payments made in cash (other than any prior distributions of Distributable Cash Flow) and (vi) to the extent not included in this clause (b) and otherwise added back in the calculation of EBITDAX, any other cash charge that reduces our earnings. The amount of Distributable Cash Flow with respect to any fiscal quarter is further reduced by all prior distributions of Distributable Cash Flow during the applicable rolling period.

Further, our Credit Facility requires us to hedge at most 90% of reasonably anticipated projected production and required us to hedge at least 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022, and at least 50% for the period from month 13 to month 30, subject to the September 2022 Waiver and the March 2023 Waiver for the limited period described above. See "Management's Discussion and Analysis of

Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement" for more information. However, as of any time, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and liquidity under the Credit Facility is equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month twenty four will be reduced to 50%, and the requirement to maintain a minimum required hedge volume for months 25 through month 30 shall be removed.

Contractual obligations and commitments

We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in consolidated debt or losses.

Derivative contracts

We have entered into derivative instruments to hedge our exposure to commodity price fluctuations. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. As of December 31, 2022, the current liability related to such contracts was $95.4 million and the non-current liability was $10.4 million. Such payments will generally be funded by higher prices received from the sale of oil, NGLs and natural gas.

As a result of the significant decline in oil, natural gas and NGL prices including natural gas basis prices in the first two months of 2023, as of February 28, 2023 the current liability related to such contracts was $8.3 million and the non-current liability was $2.9 million and we had recognized realized losses of $80.0 million.

For further information on derivative contracts, see Note 9 in the financial statements included in Item 8. Financial Statements and Supplementary Data.

Asset Retirement Obligation

At December 31, 2022, we had asset retirement obligations of $126.5 million inclusive of a current portion of $2.5 million. For further information on asset retirement obligations, see Note 7 in the financial statements included in Item 8. Financial Statements and Supplementary Data.

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, primarily for the following reasons:

Property acquisitions

We have completed three significant acquisitions in the past two years that affect the comparability of results of operations between 2021 and 2022 to some extent. We intend to continue to grow our operations through prudent acquisitions. Additionally, it is possible that we will effect divestitures of certain of our assets. We may enter into acquisitions and/or divestitures in the ordinary course of business that may affect our future operations, including our revenues and operating expenses. The following is a summary of our significant acquisition activity that occurred from the beginning of 2021 to the date of this Annual Report on Form 10-K:

- *Vacuum Acquisition*. The acquisition in November 2021 of producing properties and a gas processing plant in the Permian Basin of New Mexico and CO_2 assets in Colorado for approximately $179.3 million.

- *Andrews Parker Acquisition*. The acquisition in December 2021 of producing properties in the Permian Basin of Texas for approximately $43.7 million.

- *Additional Interest Vacuum Acquisition*. The acquisition in August 2022 of additional interest in our producing properties and a gas processing plant in the Permian Basin of New Mexico for approximately $52.8 million.

Supply, demand, market risk and their impact on oil prices.

The oil and natural gas industry is cyclical and commodity prices are highly volatile. During the period from January 1, 2021 through December 31, 2022, prices for crude oil and natural gas reached a high of $123.70 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.62 per Bbl and $2.43 per MMBtu, respectively. Oil prices steadily increased through 2021 due to continued recovery in demand before increasing drastically in the first half of 2022 due to further demand, domestic supply reductions, OPEC control measures and market disruptions resulting from the Russia-Ukraine war and sanctions on

Russia. Since the Russia-Ukraine conflict first commenced, WTI crude oil prices have been volatile, rising from $92.81 per Bbl on February 24, 2022 to a high of $123.70 per Bbl in March 2022 before declining to

$77.05 per Bbl as of February 28, 2023. Natural gas prices reached a high of $9.85 per MMbtu in August 2022 before declining to $2.50 per MMbtu as of February 28, 2023.

Other factors impacting supply and demand include weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar as well as other factors, the majority of which are outside of our control. In addition to these uncontrollable influences, there is an ongoing shift of relaxing COVID-19 containment measures worldwide, which may increase economic activity and energy demand. As a result of these external factors, we expect global commodity price volatility will continue throughout 2023. Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Please see "Risk Factors—Risks Related to the Natural Gas, NGL and Oil Industry and Our Business—Commodity prices are volatile—A sustained decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

Public company expenses

We expect to incur incremental costs in 2023 related to our transition to a publicly traded partnership, including the costs associated with the initial implementation of our internal controls implementation and testing. We also expect to incur additional significant and recurring expenses as a publicly traded partnership, including costs associated with the employment of additional personnel, compliance under the Exchange Act, annual and quarterly reports to unitholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. The direct, incremental general and administrative costs are not included in our historical financial statements.

Derivatives

To reduce the impact of fluctuations in oil, NGL and natural gas prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil, NGL and natural gas production through various transactions that limit the risks of fluctuations of future prices. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations.

Impairment

We evaluate our producing properties for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. When assessing proved properties for impairment, we compare the expected undiscounted future cash flows of the proved properties to the carrying amount of the proved properties to determine recoverability. If the carrying amount of proved properties exceeds the expected undiscounted future cash flows, the carrying amount is written down to the properties' estimated fair value, which is measured as the present value of the expected future cash flows of such properties. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, and a risk-adjusted discount rate. The proved property impairment test is primarily impacted by future commodity prices, changes in estimated reserve quantities, estimates of future production, overall proved property balances, and depletion expense. If pricing conditions decline or are depressed, or if there is a negative impact on one or more of the other components of the calculation, we may incur proved property impairments in future periods.

Critical accounting policies and estimates

Our financial position and results of operations are significantly affected by accounting policies and estimates related to our oil and gas properties, proved reserves, asset retirement obligation and commodity prices and risk management, as summarized below. See Note 1 of the notes to the audited financial statements included in Item 8. Financial Statements and Supplementary Data for an expanded discussion of our significant accounting policies and estimates made by management.

Property and equipment

A majority of the property costs reflected in the accompanying balance sheet are from the acquisition of proved properties. Successful drill well costs are transferred to proved properties generally within one month of the well completion date.

Depreciation, depletion and amortization (DD&A) of proved producing properties is computed on the unit-of- production method based on estimated proved oil and gas reserves. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that proved properties may be impaired, the carrying value of property is compared to management's future estimated pre-tax undiscounted cash flow from properties generally aggregated on a field-level basis. If impairment is necessary, the asset carrying value is written down to fair value, typically a discounted present value of estimated future cash flows. Cash flow pricing estimates are based on estimated reserves and production information and pricing assumptions that management believes are reasonable.

The impairment assessment process is primarily dependent upon the estimate of proved reserves. Any overstatement of estimated proved reserve quantities would result in an overstatement of estimated future net cash flows, which could result in an understated assessment of impairment. The subjectivity and risks associated with estimating proved reserves are discussed under "Oil and Natural Gas Reserves" below. Prediction of product prices is subjective since prices are largely dependent upon supply and demand resulting from global and national conditions generally beyond our control. However, management's assessment of product prices for purposes of impairment is consistent with that used in its business plans and investment decisions. While there is judgment involved in management's estimate of future product prices, the potential impact on impairment has not been significant recently since product prices have been substantially higher than our net acquisition and development costs per Boe. Prior to 2021, our historical impairment of proved properties included $311.5 million of proved property impairments from 2014 through 2020. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impracticable to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

Costs of retired, exchanged, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently.

Oil and natural gas reserves

Our proved oil and natural gas reserves are estimated by independent petroleum engineers. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof, including evaluation and extrapolations of well flow rates and reservoir pressure. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production, subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Because proved reserves are required to be estimated using the 12-month average prices, estimated reserve quantities can be significantly impacted by changes in product prices.

Proved reserves, as defined by the Financial Accounting Standards Board ("*FASB*") and adopted by the SEC, are limited to known reservoirs that indicate economic producibility through actual production or conclusive formation tests, and generally cannot extend beyond the immediate adjoining undrilled portion.

DD&A of producing properties is computed on the unit-of-production method based on estimated proved oil and natural gas reserves. While total DD&A expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in timing of when DD&A expense is recognized. Downward revisions of proved reserves result in an acceleration of DD&A expense, while upward revisions tend to lower the rate of DD&A expense recognition. During 2022, net upward revisions to proved reserves on a Boe basis occurred, which will result in a decrease in DD&A expense of 11% in 2023.

The standardized measure of discounted future net cash flows and changes in such cash flows, are prepared using assumptions required by FASB and the SEC. Such assumptions include 12-month average oil and natural gas prices, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures. Discounted future net cash flows are calculated using a 10% rate. Changes in any of these assumptions could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent management’s estimated current market value of proved reserves.

Revenue recognition

Oil, NGL and natural gas revenues are recognized upon the satisfaction of the performance obligation which occurs at the point in time when control of the product transfers to a customer, in an amount that reflects the consideration to which we expect to be entitled in exchange for the product.

Recent accounting pronouncements

A summary of recent accounting pronouncements and our assessment of any expected impact of these pronouncements if known is included in Note 1 to the audited consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Quantitative and Qualitative Disclosure About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. Also, gains and losses on these instruments are generally offset by losses and gains on the offsetting expenses.

Commodity price risk

Our major market risk exposure is in the pricing that we receive for our oil, NGL and natural gas production. Pricing for oil, NGLs, and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, NGL, and natural gas production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil, NGL and natural gas prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil, NGL and natural gas production through various transactions that limit the risks of fluctuations of future prices. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling. These hedging activities are intended to limit our exposure to product price volatility and to maintain stable cash flows.

As of December 31, 2022, the fair market value of our oil, NGL and natural gas derivative contracts was a net liability of $104.2 million. Based upon our open commodity derivative positions at December 31, 2022, a hypothetical 10% change in the NYMEX WTI and Henry Hub prices, OPIS prices and basis prices would change our net oil, NGL and natural gas derivative liability by approximately $26.8 million.

(in thousands)	**Fair Value at December 31, 2022**	**Hypothetical Price Increase or Decrease of 10%**
Derivative asset (liability) – Crude Oil	$ (12,626)	$ 10,168
Derivative asset (liability) – Natural Gas Liquids	$ (524)	$ 929
Derivative asset (liability) – Natural Gas	$ (91,091)	$ 15,665
	$ (104,240)	$ 26,762

The hypothetical change in fair value could be a gain or loss depending on whether prices increase or decrease.

Counterparty and customer credit risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds in major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, NGL and natural gas production to various types of customers. Credit is extended based on an evaluation of the customer’s financial condition and historical payment record. The future availability of a ready market for our production depends on numerous factors outside of our control, none of which can be predicted with certainty. For the years ended December 31, 2022 and December 31, 2021, we had two and three customers, respectively, that each accounted for more than 10% of total revenues. See “Business—Operations—Marketing and Customers.” We do not believe the loss of any single purchaser would materially impact our operating results because oil, NGLs and natural gas are fungible products with well-established markets and numerous purchasers.

At December 31, 2022, we had commodity derivative contracts with counterparties. We are currently not required to provide collateral or other security to counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, we use master netting arrangements to minimize credit risk exposure. The creditworthiness of our counterparties is subject to periodic review.

Interest rate risk

At December 31, 2022, we had $113.0 million of variable rate debt outstanding. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $1.1 million per year. We utilized the proceeds from our initial public offering and cash on hand to pay down our credit facility in full, so that we had no debt outstanding as of March 31, 2023. Based on this and the expected borrowing levels in 2023, a change in interest rates would be de minimus. See “—Liquidity and Capital Resources—Revolving credit agreement.”

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Unitholders and Board of Directors
TXO Energy Partners, L.P. and TXO Energy GP, LLC:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TXO Energy Partners, L.P. and subsidiaries (formerly known as MorningStar Partners L.P. as discussed further in Note 1) (the Partnership) as of December 31, 2022 and 2021, the related consolidated statements of operations, partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2022, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Partnership's auditor since 2012.

Dallas, Texas
March 31, 2023

TXO ENERGY PARTNERS, L.P.
Consolidated Balance Sheets

(in thousands)

	December 31, 2022	December 31, 2021
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,204	$ 7,547
Accounts receivable, net	52,304	34,124
Derivative fair value	1,242	10,632
Other	11,277	4,793
Total Current Assets	74,027	57,096
Property and Equipment, at cost—successful efforts method:		
Proved properties	1,481,233	1,376,476
Unproved properties	18,406	18,677
Other	82,210	69,254
Total Property and Equipment	1,581,849	1,464,407
Accumulated depreciation, depletion and amortization	(745,444)	(704,080)
Net Property and Equipment	836,405	760,327
Other Assets:		
Note receivable from related party	7,131	7,132
Derivative fair value	290	4,912
Other	6,779	3,353
Total Other Assets	14,200	15,397
TOTAL ASSETS	$ 924,632	$ 832,820
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities:		
Accounts payable	$ 14,686	$ 3,965
Accrued liabilities	34,128	23,758
Derivative fair value	95,371	6,450
Asset retirement obligation, current portion	2,500	1,100
Other current liabilities	779	—
Total Current Liabilities	147,464	35,273
Long-term Debt	120,100	152,100
Other Liabilities:		
Asset retirement obligation	123,958	103,389
Derivative fair value	10,401	117
Other liabilities	1,172	582
Total Other Liabilities	135,531	104,088
Commitments and Contingencies		
Partners' Capital:		
Partners' capital	521,537	541,359
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 924,632	$ 832,820

See accompanying notes to consolidated financial statements.

TXO ENERGY PARTNERS, L.P.
Consolidated Statements of Operations

(in thousands)

	Years ended December 31,		
	2022	2021	2020
REVENUES			
Oil and condensate	$ 160,864	$ 69,971	$ 59,070
Natural gas liquids	41,731	27,875	8,660
Gas	43,802	130,498	41,034
Total Revenues	246,397	228,344	108,764
EXPENSES			
Production	127,661	69,256	49,146
Exploration	360	124	55
Taxes, transportation and other	94,991	58,040	27,509
Depreciation, depletion, and amortization	41,364	39,889	42,322
Impairment	—	—	134,097
Accretion of discount in asset retirement obligation	6,055	4,670	3,940
General and administrative	1,646	12,175	6,995
Total Expenses	272,077	184,154	264,064
OPERATING (LOSS) INCOME	(25,680)	44,190	(155,300)
OTHER INCOME (EXPENSE)			
Other income	26,067	14,139	72
Interest income	143	16	194
Interest expense	(8,198)	(5,870)	(8,204)
Other Income (Expense)	18,012	8,285	(7,938)
NET (LOSS) INCOME	$ (7,668)	$ 52,475	$ (163,238)
NET (LOSS) INCOME PER COMMON UNIT			
Basic	$(0.25)	$1.71	$(5.31)
Diluted	$(0.25)	$1.71	$(5.31)
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING			
Basic	30,750	30,750	30,750
Diluted	30,750	30,750	30,750

See accompanying notes to consolidated financial statements.

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TXO ENERGY PARTNERS, L.P.
Consolidated Statements of Cash Flows

(in thousands)

	Years ended December 31,		
	2022	2021	2020
OPERATING ACTIVITIES			
Net (loss) income	$ (7,668)	$ 52,475	$ (163,238)
Adjustments to reconcile net (loss) income to net cash provided by operating activities, net of effects of assets acquired and liabilities assumed:			
Depreciation, depletion, and amortization	41,364	39,889	42,322
Impairment	—	—	134,097
Accretion of discount in asset retirement obligation	6,055	4,670	3,940
Derivative fair value (gain) loss	203,214	(8,977)	(23,305)
Net cash received from (paid to) counterparties	(89,997)	—	26,192
Non-cash gain on forgiveness of debt	—	(9,152)	—
Non-cash incentive compensation	—	2,400	4,227
Other non-cash items	715	(585)	886
Changes in operating assets and liabilities*(a)*	(17,303)	(6,994)	(6,157)
Cash Provided by Operating Activities	136,380	73,726	18,964
INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	320	—	—
Proved property acquisitions	(50,264)	(185,931)	(10,961)
Development costs	(23,720)	(8,372)	(4,989)
Unproved property acquisitions	(50)	(67)	(307)
Other property additions	(12,956)	(33,431)	(461)
Cash Used in Investing Activities	(86,670)	(227,801)	(16,718)
FINANCING ACTIVITIES			
Proceeds from long-term debt	1,461,000	1,437,000	1,932,152
Payments on long-term debt	(1,493,000)	(1,427,000)	(1,968,000)
Exercise of Series 3 Warrants	1,029	—	—
Proceeds from temporary equity investment	—	—	50,695
Proceeds from permanent equity investment	—	132,660	—
Debt issuance costs	(161)	(2,832)	(709)
Capitalized offering costs	(3,738)	—	—
Payments on vesting of restricted units	—	—	(40)
Distributions	(13,183)	(139)	(31)
Cash (Used by) Provided by Financing Activities	(48,053)	139,689	14,067
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,657	(14,386)	16,313
Cash and Cash Equivalents, beginning of period	7,547	21,933	5,620
Cash and Cash Equivalents, end of period	$ 9,204	$ 7,547	$ 21,933
(a) **Changes in Operating Assets and Liabilities**			
Accounts receivable	$ (22,753)	$ (14,811)	$ (8,103)
Other assets	(5,704)	(1,571)	(240)
Aid-in-construction asset	238	—	(238)
Current liabilities	12,401	10,028	3,224
Other operating liabilities	(1,485)	(640)	(800)
	$ (17,303)	$ (6,994)	$ (6,157)

See accompanying notes to consolidated financial statements.

TXO ENERGY PARTNERS, L.P.
Consolidated Statements of Partners' Capital

(in thousands)

	Series 3 Preferred	Series 4 Preferred	Series 5 Preferred	Common	Total
Balances, December 31, 2019	$ 34,295	$ —	$ —	$ 428,055	$ 462,350
Net loss	—	—	—	(163,238)	(163,238)
Increase in partners' equity from in-kind distributions	—	—	—	1,585	1,585
In-kind distributions	—	—	—	(1,585)	(1,585)
Expensing of unit awards	—	—	—	4,227	4,227
Withholding tax paid on vesting restricted units	—	—	—	(40)	(40)
Distributions	—	—	—	(31)	(31)
Balances, December 31, 2020	$ 34,295	$ —	$ —	$ 268,973	$ 303,268
Net income	—	—	—	52,475	52,475
Increase in partners' equity from in-kind distributions	—	—	—	8,248	8,248
In-kind distributions	—	—	—	(8,248)	(8,248)
Expensing of unit awards	—	—	—	2,400	2,400
Contributions of cash	—	—	132,660	—	132,660
Distributions	—	—	—	(139)	(139)
Accretion of original issue discount on temporary equity	—	(2,668)	—	—	(2,668)
Conversion of temporary equity to permanent equity	—	53,363	—	—	53,363
Gain (loss) from the exchange of Series 4 preferred units	—	22,719	—	(22,719)	—
Exchange of Series 4 preferred units to Series 5 preferred units	—	(73,414)	73,414	—	—
Balances, December 31, 2021	$ 34,295	$ —	$ 206,074	$ 300,990	$ 541,359
Net loss	—	—	—	(7,668)	(7,668)
Increase in partners' equity from in-kind distributions	—	—	—	1,715	1,715
In-kind distributions	—	—	—	(1,715)	(1,715)
Distributions	—	—	—	(13,183)	(13,183)
Conversion of Series 3 equity to Common equity	(34,295)		—	34,295	—
Exercise of Series 3 Warrants	—		—	1,029	1,029
Balances, December 31, 2022	$ —	$ —	$ 206,074	$ 315,463	$ 521,537

See accompanying notes to consolidated financial statements.

TXO ENERGY PARTNERS, L.P.
Notes to Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

TXO Energy Partners, L.P. (TXO Energy Partners or the Partnership) is the new name of MorningStar Partners, L.P. as of January 31, 2023. The Partnership is an independent oil and gas company that was formed as a Delaware limited partnership in January 2012 (with an effective inception of operations at January 18, 2012). The operations of TXO Energy Partners are governed by the provisions of the partnership agreement, as amended, executed by the general partner, TXO Energy GP, LLC (the General Partner) and the limited partners. The General Partner is the manager and operator of TXO Energy Partners. The General Partner is managed by the board of directors and executive officers of our General Partner. The board of directors is made up of three officers and four independent directors each of whom was appointed by MorningStar Oil & Gas, LLC (“MSOG”), as the sole member of our General Partner. Pursuant to applicable provisions of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”) and the limited partnership agreement, the partners have no liability for the debts, obligations and liabilities of TXO Energy Partners, except as expressly required in the limited partnership agreement or the Delaware Act. TXO Energy Partners will remain in existence unless and until dissolved in accordance with the terms of the partnership agreement.

TXO Energy Partners’ assets include its investment in an unincorporated joint venture. TXO Energy Partners owns 50% of the joint venture, and TXO Energy Partners is the manager of the joint venture. The joint venture is governed by a Member Management Committee (MMC) and is comprised of six representatives, three from each group, with each group having one voting member. All matters that come before the MMC require the unanimous consent of the voting members. On the last day of each calendar quarter, the joint venture distributes all excess cash to the members based on their ownership percentage of 50% each, except for earnings from the note receivable which is owned 5% by TXO Energy Partners. The joint venture’s properties are located primarily in the San Juan Basin of New Mexico and Colorado and the Permian Basin of West Texas and New Mexico.

TXO Energy Partners also has a wholly-owned subsidiary, MorningStar Operating, LLC which owns oil and gas assets primarily in the San Juan Basin of New Mexico and Colorado and the Permian Basin of West Texas and New Mexico.

In accordance with oil and gas accounting guidance, we account for our undivided interest in our investment in the joint venture using the proportionate consolidation method. Under this method, we consolidate our proportionate share of assets, liabilities, revenues and expenses of the joint venture. As discussed above, we own 50% of the oil and gas assets, liabilities, revenues and expenses, but we only own 5% of the note receivable from related party and related interest income.

In February 2015, we entered into a Limited Liability Company Agreement, as amended, with EnCap Energy Capital Fund IX, L.P. and EnCap Energy Capital Fund X, L.P. to form Southland Royalty Company LLC (Southland). On January 27, 2020, Southland filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware (January 2020 Reorganization Filing). As a result, we deconsolidated our remaining investment in Southland as of December 31, 2020. However, we remained involved with the management and wind down of Southland until Southland exited from bankruptcy in June 2021.

The accompanying consolidated financial statements include the financial statements of TXO Energy Partners, its wholly-owned subsidiaries and our undivided interests in the joint venture. All significant intercompany balances and transactions have been eliminated in consolidation.

Reorganization and Public Listing of Common Units

In January 2023, we completed a series of reorganization transactions in conjunction with publically listing our common units on the New York Stock Exchange. These included the following transactions (the Reorganization Transactions):

- We effectuated a one-for-25.33 reverse unit split;
- We caused the exchange of all outstanding Series 5 preferred units for 10,644,484 common units, resulting in our capital structure to consist of a single class of common units;
- All limited partner holders party to our amended and restated agreement of limited partnership contributed all of the outstanding equity interests in us to a new parent company, MorningStar Partners II, L.P., a Delaware limited partnership (“MSP II”) in exchange for equity interests in MSP II; and
- We amended our governing documents to, among other things, (i) change our name from “MorningStar Partners, L.P.” to “TXO Energy Partners, L.P.” and (ii) reflect TXO Energy GP, LLC, a Delaware limited liability company, as our new non-economic general partner.

As a result of these transactions, the capital structure has been reflected as if the new number of units had been in place for all periods presented.

Basis of Presentation

The accounts of TXO Energy Partners are presented in the accompanying financial statements. These financial statements have been prepared in accordance with U.S. GAAP.

Liquidity

Our primary sources of liquidity are cash provided by operating activities, borrowings under our credit facility and equity raised from partners. Short-term liquidity needs are provided by borrowings under our credit facility. We believe that we have a sufficient combination of resources and operating flexibility to ensure that we remain in compliance with our future debt covenants for all of our outstanding debt for at least the next 12 months from the date of issuance of these financial statements. See Note 4.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include the following:

- estimates of proved reserves and related estimates of the present value of future revenues;
- the recoverability of oil and gas properties;
- estimates of revenue earned but not yet received;
- asset retirement obligations; and
- legal and environmental risks and exposure.

Property and Equipment

We follow the successful efforts method of accounting, capitalizing costs of successful exploratory wells and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. All of the proved property costs reflected in the accompanying balance sheet are from TXO Energy Partners, our wholly-owned subsidiary, MorningStar Operating, LLC, and our 50% share of the joint venture's proved properties as of December 31, 2022 and 2021. Proved properties balances include costs of $17.1 million at December 31, 2022 and $2.4 million at December 31, 2021 related to wells in process of drilling. Successful drill well costs are transferred to proved properties generally within one month of the well completion date.

Depreciation, depletion, and amortization (DD&A) of proved producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. Other property and equipment is generally depreciated using the straight-line method over estimated useful lives which range from three to seven years, except for the gas processing plant which is being depreciated over an estimated useful life of 14 years. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that proved properties may be impaired, the carrying value of property is compared to management's future estimated pre-tax undiscounted cash flow from properties generally aggregated on a field-level basis. If impairment is necessary, the asset carrying value is written down to fair value, typically a discounted present value of estimated future cash flows. Cash flow pricing estimates are based on estimated reserves and production information and pricing assumptions that management believes are reasonable. During the years end ended December 31, 2022 and 2021, we did not recognize an impairment of long-lived assets. During the year end ended December 31, 2020, we recognized an impairment of long-lived assets of $133.2 million for our assets in the New Mexico Permian Basin, $0.2 million for our assets in East Texas and $0.7 million on our unproved properties primarily in the Texas Permian Basin primarily due to a lower net commodity price environment for some of our oil and natural gas assets.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion, and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized in the current period.

Asset Retirement Obligation

If the fair value for asset retirement obligation can be reasonably estimated, the liability is recognized in the period when it is incurred. Oil and gas producing companies incur this liability upon acquiring or drilling a well. The retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to proved properties on the balance sheet. Periodic accretion of discount of the estimated liability is recorded as an expense in the statements of operations. See Note 7.

Cash and Cash Equivalents

Cash equivalents are considered to be all highly liquid investments having an original maturity of three months or less.

Fair Value of Financial Instruments

Fair value is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

Assets and liabilities recorded at fair value in the consolidated balance sheets are categorized based upon the level of judgment associated with the inputs used to measure their fair value. Hierarchical levels directly related to the amount of subjectivity associated with the inputs to fair valuation of these assets and liabilities are as follows:

Level I—Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

Level II—Inputs (other than quoted prices included in Level I) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level III—Inputs reflect management’s best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

Income Taxes

TXO Energy Partners is a limited partnership treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with income tax liabilities and/or benefits of the Partnership passed through to the partners. As such, with the exception of the state of Texas, we are not a taxable entity, we do not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for our operations, except as described below.

Limited partnerships are subject to state income taxes in Texas. Due to immateriality, income taxes related to the Texas margin tax have been included in general and administrative expenses on the statement of operations and no deferred tax amounts were calculated.

Derivatives

We use derivatives to hedge against changes in cash flows related to product price, as opposed to their use for trading purposes. We record all derivatives on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative’s fixed contract price and the underlying market price at the determination date. See Note 9.

We do not designate these derivative contracts as cash flow hedges. Changes in the fair value of commodity price derivatives are recognized currently in earnings. Realized and unrealized gains and losses on commodity derivatives are recognized in oil and gas revenues. Settlements of derivatives are included in cash flows from operating activities.

Revenue Recognition

Oil, gas and natural gas liquids revenues are recognized upon the satisfaction of the performance obligation which occurs at the point in time when control of the product transfers to a customer, in an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for the product. See Note 13 for further discussion.

Loss Contingencies

When management determines that it is probable that an asset has been impaired or a liability has been incurred, we accrue our best estimate of the loss if it can be reasonably estimated. Any legal costs related to litigation are expensed as incurred.

Unit-Based Compensation

We recognize compensation related to all unit-based awards in the financial statements based on their estimated grant-date fair value. We estimate expected forfeitures and we recognize compensation expense only for those awards expected to vest. Compensation expense is amortized on a straight-line basis over the estimated service period. All compensation is recognized by the time the award vests. See Note 12.

Segments

We evaluated how TXO Energy Partners is organized and managed and have identified only one operating segment, which is the exploration and production of oil, natural gas and natural gas liquids. All of our assets are located in the United States, and all revenues are attributable to United States customers.

Significant Purchasers

Our production is sold to various purchasers, based on their credit rating and the location of our production. Sales to two purchasers for the year ended December 31, 2022, sales to three purchasers for the year ended December 31, 2021, and sales to two purchasers for the year ended December 31, 2020, as shown in the table below, were greater than 10% of

total revenues. We believe that alternative purchasers are available, if necessary, to purchase production at prices substantially similar to those received from these significant purchasers.

Customer	2022	2021	2020
Customer A	24 %	— %	— %
Customer B	11 %	19 %	25 %
Customer C	— %	12 %	17 %
Customer D	— %	11 %	— %

Earnings per Common Unit

We report basic earnings per unit, which excludes the effect of potentially dilutive securities, and diluted earnings per common unit, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. See Note 11.

2. Acquisitions

In August 2022, TXO Energy Partners completed the acquisition of additional interest in our producing properties and gas processing plant in the Permian Basin of New Mexico from Vendera Resources for approximately $52.8 million. Our purchase price allocation included $50.0 million to proved properties, $9.8 million to other properties, $3.7 million as a reduction to other current assets, $0.2 million to other current liabilities and $3.1 million to asset retirement obligation. The acquisition was funded by borrowings from our credit facility.

In February 2022, TXO Energy Partners completed the acquisition of producing properties in the Permian Basin of Texas from Kaiser Francis for approximately $3.8 million. Our purchase price allocation included $4.0 million to proved properties and $0.2 million to asset retirement obligation. The acquisition was funded by cash on hand.

During 2022, we completed multiple acquisitions of producing properties in the Permian Basin of Texas and New Mexico for $0.6 million. We allocated $0.6 million to proved property.

In December 31, 2021, TXO Energy Partners completed the acquisition of producing properties in the Permian Basin of Texas from Chevron for approximately $43.7 million. Our purchase price allocation included $47.3 million to proved properties, to $0.2 million current liabilities and $3.4 million to asset retirement obligation. The acquisition was funded by cash on hand and borrowings from our credit facility.

In November 2021, TXO Energy Partners completed the acquisition of producing properties and a gas processing plant in the Permian Basin of New Mexico and CO_2 assets in Colorado from Chevron for approximately $179.3 million. Our purchase price allocation included $150.9 million to proved properties, $34.4 million to other properties, $3.6 million to other current assets, $2.2 million to other current liabilities and $7.4 million to asset retirement obligation. The acquisition was funded by cash on hand from the October 2021 capital raise (see Note 10) and borrowings from our credit facility. In the 2021 statement of operations, we recorded $15.0 million of revenues and income of $2.8 million from this acquisition.

In June 2020, TXO Energy Partners completed the acquisition of producing properties in the San Juan Basin of New Mexico and Colorado from Southland Royalty for approximately $10.2 million. Our purchase price allocation included $69.0 million to proved properties, $54.6 million to asset retirement obligation, $4.0 million to other current liabilities and $0.2 million to other liabilities. The acquisition was funded by cash on hand.

During 2020, we completed multiple acquisitions of producing properties in the Permian Basin of Texas and New Mexico for $0.7 million. We allocated $0.7 million to proved property. These were funded by cash on hand.

Pro forma financial information (Unaudited)

The following pro forma financial information represents the results for the Partnership and the properties acquired in November 2021 in the Permian Basin of New Mexico and CO_2 assets in Colorado from Chevron as if the acquisition and the required financing had occurred on January 1, 2020.

For the pro forma year ended December 31, 2021, pro forma revenues were $278.7 million and pro forma net income was $61.4 million. For the purposes of the pro forma, it was assumed that $40.0 million of the Partnership's revolving credit facility was used to finance the acquisition resulting in additional interest expense of $1.3 million. The pro forma financial information includes the effects of adjustments for depreciation, depletion, and amortization of $7.8 million, and accretion of asset retirement obligations expense of $0.3 million.

For the pro forma year ended December 31, 2020, pro forma revenues were $149.2 million and pro forma net loss was $159.0 million. For the purposes of the pro forma, it was assumed that $40.0 million of the Partnership's revolving credit facility was used to finance the acquisition resulting in additional interest expense of $1.6 million. The pro forma financial information includes the effects of adjustments for depreciation, depletion, and amortization of $11.0 million, and accretion of asset retirement obligations expense of $0.4 million.

The pro forma results do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Partnership to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

3. Related Party Transactions

We earned management fees from the joint venture of $5.9 million for the year ended December 31, 2022, $6.1 million for the year ended December 31, 2021, and $6.4 million for the year ended December 31, 2020. As of December 31, 2022, we had a note receivable from related party outstanding with a highly-rated, offshore subsidiary of our joint venture partner (Note 5). On September 30, 2016, TXO Energy Partners entered in a loan agreement with the joint venture (Note 4).

We earned management fees from Southland of less than $0.1 million for the year ended December 31, 2022, $5.0 million for the year ended December 31, 2021, and $15.5 million for the year ended December 31, 2020.

Since the purpose of the management fees is to share costs between the various entities, the management fees from the joint venture and Southland are included as a reduction of general and administrative expenses in our statements of operations.

We occupy a building owned by MorningStar Capital LLC, a limited liability company owned by our Chief Executive Officer and the Chairman of the Board. In lieu of paying rent, we paid property taxes and paid for repairs and maintenance on behalf of MorningStar Capital LLC of $0.9 million in 2022, $0.9 million in 2021 and $1.5 million in 2020.

4. Debt

(in thousands)	December 31, 2022	December 31, 2021
November 2021 Credit Facility, at 7.8% at December 31, 2022 and 4.0% at December 31, 2021	$ 113,000	$ 145,000
September 2016 Loan, 7.4% at December 31, 2022 and 3.4% at December 31, 2021	$ 7,100	$ 7,100
Total Long-term Debt	$ 120,100	$ 152,100

November 2021 Credit Facility

On November 1, 2021, we entered into a new four-year, $165 million senior secured credit facility with certain commercial banks. The facility has a maturity date of November 1, 2025. We use the facility for general corporate purposes. In connection with entering into the credit facility, we incurred financing fees and expenses of approximately $2.8 million as of December 31, 2022 and $2.7 million as of December 31, 2021 before accumulated amortization of $0.8 million as of December 31, 2022 and $0.1

million as of December 31, 2021. These costs are being amortized over the life of the credit facility. Such amortized expenses are recorded as interest expense on the statements of operations.

Redetermination of the borrowing base under the credit facility, is based primarily on reserve reports that reflect commodity prices at such time, occurs semi-annually, in March and September, as well as upon requested interim redeterminations, by the lenders at their sole discretion. We also have the right to request additional borrowing base redeterminations each year at our discretion. Significant declines in commodity prices may result in a decrease in the borrowing base. These borrowing base declines can be offset by any commodity price hedges we enter. Our obligations under the credit facility are secured by substantially all assets of the Partnership, including, without limitation, (i) our interest in the joint venture, (ii) all our deposit accounts, securities accounts, and commodities accounts, (iii) any receivables owed to us by the joint venture and (iv) any oil and gas properties owned directly by TXO Energy Partners or its wholly-owned subsidiaries. We are required to maintain (i) a current ratio greater than 1.0 to 1.0 and current assets shall include availability under the credit facility but shall exclude the fair value of derivative instruments and any advances under the facility and (ii) a ratio of total indebtedness-to-EBITDAX of not greater than 3.0 to 1.0. The total EBITDAX calculation is limited to the joint venture's EBITDAX that has been paid in cash to TXO Energy Partners through distributions, plus MorningStar Operating LLC's EBITDAX results plus realized hedge gains less realized hedge losses and the consolidated expenses of TXO Energy Partners and its subsidiaries. EBITDAX means sum of (i) net income plus interest expense; income taxes paid; depreciation, depletion and amortization; exploration expenses, including workover expenses; non-cash charges including unrealized losses on derivative instruments; and, any extraordinary or non-recurring charges, minus (ii) any extraordinary or non-recurring income and any non-cash income including unrealized gains on derivative instruments. We are required to hedge at least 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022, and at least 50% for the period from month 13 to month 30. However, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and liquidity under the Credit Facility is equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month twenty-four will be reduced to 50% and the requirement to maintain the minimum required hedge volume for months 25 through 30 shall be removed. Our Credit Facility prohibits us from hedging more than 90% of our reasonably projected production for any fiscal year. From September 30, 2022 through the next scheduled spring redetermination which shall occur no later than June 30, 2023, we received waivers to reduce the hedging requirement from 30 months to 15 months and from 50% to 45% of the reasonably anticipated projected production. We were in compliance with all of our debt covenants as of December 31, 2022 and 2021. Additionally, we believe with have adequate liquidity to continue as going concern for at least the next twelve months from the date of this report.

At our election, interest on borrowings under the credit facility is determined by reference to either the secured overnight financing rate ("SOFR") plus an applicable margin between 3.00% and 4.00% per annum (depending on the then-current level of borrowings under the Credit Facility) or the alternate base rate ("ABR") plus an applicable margin between 2.00% and 3.00% per annum (depending on the then-current level of borrowings under the Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at SOFR. We are required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum of 0.5% on the average daily unused amount of the lesser of: (i) the maximum commitment amount of the lenders and (ii) the then-effective borrowing base. The weighted average interest rate on credit facility borrowings was 5.4% in 2022 and 4.0% in 2021.

We utilized the proceeds from our initial public offering and cash on hand to pay down our credit facility in full, so that we had no debt outstanding and $165.0 million available under our Credit Facility as of March 31, 2023.

September 2016 Loan

On September 30, 2016, TXO Energy Partners entered into an unsecured loan agreement with the joint venture (the "FAM Loan"). The proceeds for the loan were taken from the cash held by the offshore subsidiary of Exxon Mobil Corporation and the loan was assigned to the offshore subsidiary (Note 5). The loan matures on January 31, 2026, but is automatically extended should our credit facility be extended. In all instances, this loan will mature ninety-one days after the maturity of the Credit Facility. Interest on the loan is the lesser of (a) London Interbank Offered Rate ("LIBOR") plus three and one-quarter of one percent (3.25%) per annum, adjusted monthly or (b) the highest rate permitted by applicable law. Though the note is unsecured, we are required to stay in compliance with terms of our Credit Facility. The weighted average interest rate on loan was 5.1% in 2022 and 3.4% in 2021.

Paycheck Protection Program Loans

On April 13, 2020, we received a loan of approximately $7.2 million under the US Government's Paycheck Protection Program from the Small Business Administration ("SBA"). Under the terms of the loan, it was required to be repaid beginning November 13, 2020 in equal installments until April 13, 2022, unless we qualified for loan forgiveness. The loan bore interest at a rate of 1% per annum. In August 2020, we sent in our loan forgiveness application for the entire loan amount. As a result of filing the application, we did not make any payments on the loan, nor did we accrue any interest on the loan in 2020. On June 14, 2021 we received notice that the loan was forgiven in full. We recorded this loan forgiveness as other income on the statements of operations.

On January 27, 2021, we received a second loan for $2.0 million under an extension of the US Government's Paycheck Protection Program from the SBA. On July 2, 2021 we received notice that the loan was forgiven in full. We recorded this loan forgiveness as other income on the statements of operations.

5. Note Receivable from Related Party

As of December 31, 2022 and 2021, we, through our 5% ownership interest in investment assets at the joint venture, had a note receivable totaling $7.1 million outstanding with a highly-rated, offshore subsidiary of our joint venture partner. Under the terms of the agreement, there is no stated maturity date and, the joint venture may demand repayment of all or any portion of the outstanding balance on two business days' notice. Interest is earned based on the one-month LIBOR rate and is paid monthly. Interest income totaled $0.1 million in 2022, less than $0.1 million in 2021 and $0.2 million in 2020.

The note receivable is treated as a non-current asset, since the joint venture does not have any intention of demanding repayment of all or any portion of the outstanding balance at this time. Repayment would require the approval of the joint venture MMC.

6. Commitments and Contingencies

From time to time, the Partnership is subject to various claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Partnership.

To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Commodity Commitments

During 2022, 2021 and 2020, we entered into futures contracts and swap agreements that effectively fixed natural gas and crude oil prices. See Note 9.

7. Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state and federal laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of asset retirement obligation activity for the years ended December 31, 2022 and 2021:

	(in thousands) 2022	2021
Asset retirement obligation, January 1	$ 104,489	$ 100,670
Revisions in the estimated cash flows (1)	14,174	(7,157)
Liability incurred upon acquiring and drilling wells	3,357	10,741
Liability settled upon sale of wells	—	(3,580)
Liability settled upon plugging and abandoning wells	(1,617)	(855)
Accretion of discount expense	6,055	4,670
Asset retirement obligation, December 31	126,458	104,489
Less current portion	(2,500)	(1,100)
Asset retirement obligation, long term	$ 123,958	$ 103,389

(1) Revisions in the estimated cash flows for the years ended December 31, 2022 and 2021 are primarily the result of revised cost estimates.

8. Fair Value

We use commodity-based and financial derivative contracts to manage exposures to commodity price. We do not hold or issue derivative financial instruments for speculative or trading purposes. We periodically enter into futures contracts, costless collars, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales (Note 9).

Fair Value of Financial Instruments

Because of their short-term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at December 31, 2022 and 2021. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2022		December 31, 2021	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Note receivable from related party	$ 7,131	$ 7,131	$ 7,132	$ 7,132
Long-term debt	$ (120,100)	$ (120,100)	$ (152,100)	$ (152,100)
Derivative asset	$ 1,532	$ 1,532	$ 15,544	$ 15,544
Derivative liability	$ (105,772)	$ (105,772)	$ (6,567)	$ (6,567)

The fair value of our note receivable from related party approximates the carrying amount because the interest rate is based on current market interest rates and can be called upon two business days' notice (Note 5). The fair value of our long-term debt approximates the carrying amount because the interest rate is reset periodically at then current market rates (Note 4).

The fair value of our note receivable from related party (Note 5), net derivative asset (Note 10) and our long-term debt (Note 4) is measured using Level II inputs, and are determined by either market prices on an active market for similar assets or other market-corroborated prices. Counterparty credit risk is considered when determining the fair value of our notes receivable and net derivative asset. Since our counterparty is highly rated, the fair value of our note receivable from related party does not require an adjustment to account for the risk of nonperformance by the counterparty, however, an adjustment for counterparty credit risk, including our own credit risk, has been applied to the net derivative (liability)/asset.

The following table summarizes our fair value measurements and the level within the fair value hierarchy in which the fair value measurements fall.

	Fair Value Measurements			
	December 31, 2022		December 31, 2021	
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Note receivable from related party	$ 7,131	$ —	$ 7,132	$ —
Long-term debt	$ (120,100)	$ —	$ (152,100)	$ —
Derivative asset	$ 1,532	$ —	$ 15,544	$ —
Derivative liability	$ (105,772)	$ —	$ (6,577)	$ —

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments whenever events or circumstances indicate that the carrying value of those assets may not be recoverable and are based upon Level 3 inputs. These assets and liabilities can include assets and liabilities acquired in a business combination, proved and unproved natural gas properties, asset retirement obligations and other long-lived assets that are written down to fair value when they are impaired.

We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. We review our oil and natural gas properties by asset group. The estimated future net cash flows are based upon the underlying reserves and anticipated future pricing. An impairment loss is recognized if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of a particular asset, the Partnership recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of such assets. The fair value of the proved properties is measured based on the income approach, which incorporates a number of assumptions involving expectations of future product prices, which the Partnership bases on the forward-price curves, estimates of oil and gas reserves, estimates of future expected operating and capital costs and a risk adjusted discount rate of 10%. These inputs are categorized as Level 3 in the fair value hierarchy. We did not recognize any impairment in the years ended December 31, 2022 and 2021. We did recognize an impairment of $134.1 million in the year ended December 31, 2020.

Commodity Price Hedging Instruments

We periodically enter into futures contracts, energy swaps, options, collars and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas and natural gas liquids sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. See Note 9.

The fair value of our derivatives contracts consists of the following:

	Asset Derivatives		Liability Derivatives	
	December 31,		December 31,	
(in thousands)	2022	2021	2022	2021
Derivatives not designated as hedging instruments:				
Crude oil futures and differential swaps	$ 968	$ 2,342	$ (13,594)	$ (1,996)
Natural gas liquids futures	$ —	$ 685	$ (524)	$ (204)
Natural gas futures, collars and basis swaps	$ 564	$ 12,517	$ (91,654)	$ (4,367)
Total	$ 1,532	$ 15,544	$ (105,772)	$ (6,567)

As a result of the significant decline in oil, natural gas prices and NGL prices including natural gas basis prices in the first two months of 2023, the fair value of our derivatives as of February 28, 2023 consists of the following:

	Asset Derivatives		Liability Derivatives	
	February 28,		February 28,	
(in thousands)	2023		2023	
Derivatives not designated as hedging instruments:				
Crude oil futures and differential swaps	$	453	$	(9,379)
Natural gas liquids futures	$	529	$	(1,677)
Natural gas futures, collars and basis swaps	$	4,421	$	(154)
Total	$	5,403	$	(11,210)

As of February 28, 2023, we had recognized realized losses of $80.0 million.

Derivative fair value (gain) loss, included as part of the related revenue line on the consolidated statements of operations, comprises the following realized and unrealized components:

(in thousands)	2022		2021		2020	
Net cash (received from) paid to counterparties	$	89,997	$	—	$	(26,192)
Non-cash change in derivative fair value	$	113,217	$	(8,977)	$	2,887
Derivative fair value (gain) loss	$	203,214	$	(8,977)	$	(23,305)

Concentrations of Credit Risk

Our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss from the other companies. Including the bank that issued the letter of credit, we currently have greater concentrations of credit with several investment-grade (BBB- or better) rated companies.

9. Commodity Sales Commitments

Our policy is to consider hedging a portion of our production at commodity prices the general partner deems attractive. While there is a risk we may not be able to realize the benefit of rising prices, the general partner may enter into hedging agreements because of the benefits of predictable, stable cash flows.

We enter futures contracts, energy swaps, options and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We also enter costless price collars, which set a ceiling and floor price to hedge our exposure to price fluctuations on natural gas sales. When actual commodity prices exceed the ceiling price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the floor price, we receive this difference from the counterparty. If the actual commodity price falls in between the ceiling and floor price, there is no cash settlement.

Crude Oil

We have entered into crude oil futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 9.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl
January 2023—December 2023	2,500	$ 68.87
January 2024—June 2024	2,000	$ 63.27

The price we receive for our oil production is generally different than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors. We have entered sell basis swap agreements that effectively fix the basis adjustment for the West Texas Midlands delivery location for the production and periods shown below.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl(a)
January 2023—December 2023	5,000	$ 1.21

(a) Increases to NYMEX oil price for delivery location

The price we receive for our oil production is generally different than the NYMEX price because of changes in the roll component of the NYMEX price due to the timing of when the monthly NYMEX price is set. We have entered sell basis swap agreements that effectively fix the roll component of the NYMEX price for the production and periods shown below.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl(a)
January 2023—December 2023	3,000	$ 0.89

(a) Increases to NYMEX oil price for roll component

Net settlement losses in 2022 and gains in 2021 and 2020 on oil futures and sell basis swap contracts decreased oil revenues by $32.8 million in 2022 and increased oil revenues by $0.0 million in 2021 and by $27.2 million in 2020. An unrealized loss in 2022 and 2020 and an unrealized gain in 2021 to record the fair value of derivative contracts decreased oil revenues by $13.0 million in 2022, increased oil revenues by $0.3 million in 2021 and decreased oil revenues by $3.0 million in 2020.

Natural Gas Liquids

We have entered into natural gas liquids futures contracts and swap agreements for certain components—ethane and propane—that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 9.

Production Period	Gallons per Day	Weighted Average NGL OPIS Price per Gallon
Ethane		
January 2023—December 2023	63,000	$ 0.27
January 2024—June 2024	63,000	$ 0.23

Net settlement losses on NGL futures contracts and swap agreements decreased NGL revenues by $4.6 million in 2022 and none in 2021. An unrealized loss in 2022 and an unrealized gain in 2021 to record the fair value of derivative contracts decreased NGL revenues by $1.0 million in 2022 and increased NGL revenues by $0.5 million.in 2021. Since we had no NGL futures contracts and swap agreements outstanding in 2020, there was no effect on NGL revenues in 2020.

Natural Gas

We have entered into natural gas futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 9.

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu
January 2023—December 2023	35,000	$ 3.51
January 2024—June 2024	30,000	$ 3.26

We have also entered into gas collars that set a ceiling and floor price for the production and periods shown below.

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu	
		Floor	Ceiling
January 2023—March 2023	5,000	$ 5.00	$ 9.85
January 2024—June 2024	5,000	$ 3.75	$ 7.25

The price we receive for our gas production is generally less than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors. We have entered sell basis swap agreements that effectively fix the basis adjustment for the San Juan Basin delivery location for the production and periods shown below.

Production Period	MMBtu per Day	Weighted Average Sell Basis Price per MMBtu(a)
January 2023—December 2023	70,000	$ 0.17

(a) Reductions to NYMEX gas price for delivery location

Net settlement losses on gas futures and sell basis swap contracts decreased gas revenues by $52.6 million in 2022, none in 2021 and $1.0 million in 2020. An unrealized loss in 2022 and an unrealized gain in 2021 and 2020 to record the fair value of derivative contracts decreased gas revenues by $99.2 million in 2022 and increased gas revenues by $8.2 million in 2021 and $0.1 million in 2020.

10. Partners’ Capital

Partners’ Units

Under the terms of the amended partnership agreement, there are two classes of units, Common Units and Preferred Units. The general partner establishes the number of authorized units and as of December 31, 2022, the general partner has not established the authorized number of Common Units. All of the Common Unit and per Common Unit amounts herein are presented as if the January 2023, one-for-25.33 reverse stock split had taken place January 1, 2020.

In conjunction with an offering in August 2019, we created a new class of Preferred Units, Series 3 Preferred Units. Each Series 3 Preferred Unit cost $25 per preferred unit and also included warrants to purchase an additional 0.1 common units for $25.33. The Series 3 Preferred Units received semi-annual distributions in the amount of $0.625 per preferred unit. A holder of Series 3 Preferred Units will received in-kind distributions of Common Units for their Series 3 Preferred Units. The semi-annual distributions were paid in April and October. The Series 3 Preferred Units automatically converted to 0.2 Common Units for each preferred unit on October 1, 2022. Additionally, all of the warrants were exercised on October 1, 2022.

In conjunction with an offering in July 2020, we created an additional class of Preferred Units, Series 4 Preferred Units. Each Series 4 Preferred Unit was issued at $95,000 per preferred unit (an original issue discount of $5,000 per preferred unit) and also included warrants equal to, in the aggregate, 20% non-dilutable common units, at the time of exercise. These warrants had a term of five years from the date of closing and an exercise price of $0.25 each. If holders of a majority of the warrants elected to exercise the warrants, then all warrants were required to be exercised at the same time. There was also a group of backstop investors that provided a minimum amount of capital of a least $35 million. These backstop investors received an arrangement fee in the form of warrants to purchase common units for $0.25 per common unit, with warrants equal to, in the aggregate, 10% non-dilutable common units at the time of exercise. These warrants had a term of 15 years. The Series 4 Preferred Units received a semi-annual payment of 12% paid-in-kind common units at $5.07 per common unit or 10% cash pay as permitted. The Partnership could call the Series 4 Preferred Units at any time and at a cost of $100,000 per preferred unit plus any accrued dividends at such date. However, if we called the Series 4 Preferred Units on or prior to the second anniversary of the offering, we were required to pay $130,000 per preferred unit. Beginning August 1, 2025, the Series 4 Preferred Units could be put back to us for repayment at a cost of $100,000 per preferred unit plus any accrued dividends at such date. As a result of our offering, we issued 533.63 preferred units for total proceeds of $50.4 million net of $0.3 million of offering costs. The proceeds were used to pay down $35 million on our Credit Facility (see Note 4) and the remainder was retained for future cash needs.

In conjunction with an offering in October 2021, we created an additional class of Preferred Units, Series 5 Preferred Units. Each Series 5 Preferred Unit was issued at $100,000 per preferred unit. The Series 5 Preferred Units receive a semi-annual payment of 6.25% paid-in cash. The Series 5 Preferred Units automatically convert to Common Units at a rate of $20.26 per unit no later than October 15, 2024. In conjunction with our offering, all Series 4 Preferred Units were exchanged into Series 5 Preferred Units at a rate of 1.4 Series 5 Preferred Units for each Series 4 Preferred Unit. Additionally, all Series 4 warrants were converted to Common Units effective October 2021 at no cost to the warrant holder. The impact of the exchange of Series 4 Preferred Units to Series 5 Preferred Units coupled with the non-cash conversion of Series 4 warrants to Common Units accrued to the benefit of the Series 4 Preferred unitholders, who also own approximately 90% of the Common Units. The actual effect of this conversion was to transfer $22.7 million of value from the Common Unit holders to the Series 4 Preferred Unit holders. As a result of the offering, we issued 2,073.69 preferred units for total proceeds of $132.6 million net of $0.1 million of offering costs. There are no Series 4 Preferred Units or warrants still outstanding.

The proceeds, in conjunction with cash on hand and borrowings under our credit facility, were used to acquire producing properties and a gas processing plant in the Permian Basin of New Mexico and CO_2 assets in Colorado from Chevron (see Note 2).

Effective with the public listing of our common units on January 31, 2023, all of the outstanding Series 5 Preferred Units were exchanged for 10,644,484 Common Units, such that there is only one class of units outstanding. After the exchange, we had 25,000,000 Common Units outstanding.

Prior to April 1st of each year, the general partner shall determine the fair value of a Common Unit as of January 1st of such year. However, the general partner can change the fair value of a Common Unit should circumstances indicate that a material change in value has occurred. The fair value was determined to be $10.13 per Common Unit as of January 1, 2021 and $22.03 per Common Unit as of January 1, 2022. The fair value was not calculated for January 1, 2023, since the Common Units are now publically traded. The fair value established by the general partner was used for all purposes until the next redetermination.

The following reflects our partners' Common Unit and Preferred Unit activity for the years ended December 31, 2022, 2021 and 2020 (in thousands):

	2020			
	Common Units	Series 3 Preferred Units	Series 4 Preferred Units	Series 5 Preferred Units
Balance, beginning of period	7,076	1,372	—	—
Vesting of restricted units, net of income taxes	42	—	—	—
Common units surrendered to pay off share notes	(37)	—	—	—
Common units received in lieu of distribution	38	—	—	—
Preferred units purchased	—	—	1	—
Balance, December 31	7,119	1,372	1	—

	2021			
	Common Units	Series 3 Preferred Units	Series 4 Preferred Units	Series 5 Preferred Units
Balance, beginning of period	7,119	1,372	1	—
Vesting of restricted units, net of income taxes	118	—	—	—
Warrants converted to common units	5,427	—	—	—
Common units received in lieu of distribution	1,302	—	—	—
Preferred units purchased	—	—	—	1
Preferred units exchanged for new preferred units	—	—	(1)	1
Balance, December 31	13,966	1,372	—	2

	2022			
	Common Units	Series 3 Preferred Units	Series 4 Preferred Units	Series 5 Preferred Units
Balance, beginning of period	13,966	1,372	—	2
Warrants converted to common units	81	—	—	—
Common units received in lieu of distribution	38	—	—	—
Preferred units converted to common units	271	(1,372)	—	—
Balance, December 31	14,356	—	—	2

Distributions

During 2022, we paid in-kind distributions of 37,615 units with a value of $1.7 million to our Series 3 Preferred holders. During 2021, we paid in-kind distributions of 1.3 million units with a value of $6.4 million to our Series 5 Preferred holders and 37,615 units with a value of $1.8 million to our Series 3 Preferred holders. During 2020, we paid in-kind distributions of 37,615 units with a value of $1.6 million to our Series 3 Preferred holders.

The determination of the amount of future distributions on the Common Units, if any, to be declared and paid is at the sole discretion of the general partner and will depend on our financial condition, earnings and cash flow from operations, the level of debt outstanding, the level of our capital expenditures, our future business prospects and other matters the general partner deems relevant.

See Note 12.

11. Earnings per Unit

The following represents basic and diluted earnings (loss) per Common Unit upon the Reorganization (See Note 1) and corresponding issuance of 30.8 million Common Units:

(in thousands, except per unit data)	Net (loss) income	Units	(Loss) Income per Unit
2022			
Basic	$ (7,668)	30,750	$(0.25)
Effect of dilutive securities	—	—	
Diluted	$ (7,668)	30,750	$(0.25)
2021			
Basic	$ 52,475	30,750	$1.71
Effect of dilutive securities	—	—	
Diluted	$ 52,475	30,750	$1.71
2020			
Basic	$ (163,238)	30,750	$(5.31)
Effect of dilutive securities	—	—	
Diluted	$ (163,238)	30,750	$(5.31)

12. Employee Benefit Plans

Unit Incentive Plans

Unit incentive awards under the 2012 Employee Equity Incentive Plan (2012 Plan) included unit awards which were subject to such restrictions as determined by the general partner. Under the terms of the 2012 Plan, 0.1 million units were available for grants of unit awards. On December 31, 2019, the Plan was amended to increase the amount of units available for grant to 0.2 million units. In connection with the offering, this plan was replaced by a new long-term incentive plan (see below).

We recognized non-cash restricted unit compensation expense of $0.0 million in 2022, $2.4 million in 2021 related to a fully-vested grant of 118,457 units and $4.2 million in 2020.

At the time of the public offering in January 2023, we adopted a new long-term incentive plan. Under the 2023 Long-Term Incentive Plan (LTIP), the general partner may issue long-term equity based awards to directors, officers and employees of our general partner or its affiliates, or to any consultants, affiliates of our general partner or other individuals who perform services for us. The LTIP provides for the grant, from time to time at the discretion of the board of directors of our general partner or any delegate thereof, of cash awards, unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and other unit-based awards. Under the terms of the LTIP, 2.0 million units are available for grants of awards.

In connection with the offering, the board approved grants of 545,000 phantom units with distribution equivalent rights to the non-employee directors, officers and certain key employees. These phantom units will vest ratably over a three year period for the officers and key employees and will fully vest on the one-year anniversary of the grant for the non-employee directors. The phantom units will be settled in common units and distribution equivalents will be paid to holders of outstanding phantom units, including unvested phantom units.

13. Revenue from Contracts with Customers

The Partnership recognizes sales of oil, natural gas, and NGLs when it satisfies a performance obligation by transferring control of the product to a customer, in an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for the product.

As discussed in Note 9, the Partnership recognizes the impact of derivative gains and losses as a component of revenue. See table below for the reconciliation of revenue from contracts with customers and derivative gains and losses.

	Year Ended December 31, 2022			
	Oil and condensate	**Natural gas liquids**	**Natural gas**	**Total Revenues**
	(in thousands)			
Revenue from customers	$ 206,656	$ 47,323	$ 195,632	$ 449,611
Unrealized gain (loss) on derivatives	(12,972)	(1,005)	(99,240)	(113,217)
Realized gain (loss) on derivatives	(32,820)	(4,587)	(52,590)	(89,997)
Total Revenues	$ 160,864	$ 41,731	$ 43,802	$ 246,397

	Year Ended December 31, 2021			
	Oil and condensate	**Natural gas liquids**	**Natural gas**	**Total Revenues**
	(in thousands)			
Revenue from customers	$ 69,625	$ 27,394	$ 122,348	$ 219,367
Unrealized gain (loss) on derivatives	346	481	8,150	8,977
Realized gain (loss) on derivatives	—	—	—	—
Total Revenues	$ 69,971	$ 27,875	$ 130,498	$ 228,344

	Year Ended December 31, 2020			
	Oil and condensate	**Natural gas liquids**	**Natural gas**	**Total Revenues**
	(in thousands)			
Revenue from customers	$ 34,885	$ 8,660	$ 41,914	$ 85,459
Unrealized gain (loss) on derivatives	(2,957)	—	70	(2,887)
Realized gain (loss) on derivatives	27,142	—	(950)	26,192
Total Revenues	$ 59,070	$ 8,660	$ 41,034	$ 108,764

Natural Gas and NGL Sales

Under our natural gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or at the inlet of a facility. The midstream provider gathers and processes the product and both the residue gas and the resulting natural gas liquids are sold at the tailgate of the plant. The Partnership's natural gas production is primarily sold under market-sensitive contracts that are typically priced at a differential to the published natural gas index price for the producing area due to the natural gas quality and the proximity to the market. We evaluated these arrangements and determined that control of the products transfers at the tailgate of the plant, meaning that the Partnership is the principal and the third-party purchaser is its customer. As such, we present the gas and NGL sales on a gross basis and the related gathering and processing costs as a component of taxes, transportation, and other on the statement of operations.

Oil and Condensate Sales

Oil production is sold at the wellhead under market-sensitive contracts at an index price, net of pricing differentials. The Partnership recognizes revenue upon the satisfaction of the performance obligation which occurs at the point in time when control of the product transfers to a customer, in an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for the product. This treatment after the adoption of ASC 606 is consistent with the treatment under ASC 605 and has no impact on revenues or expenses on the statement of operations.

Production imbalances

The Partnership uses the sales method to account for production imbalances. If the Partnership's sales volumes for a well exceed the Partnership's proportionate share of production from the well, a liability is recognized to the extent that the Partnership's share of estimated remaining recoverable reserves from the well is insufficient to satisfy the imbalance. No receivables are recorded for those wells on which the Partnership has taken less than its proportionate share of production.

Contract Balances

Under the Partnership's product sales contracts, its customers are invoiced once the Partnership's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Partnership's product sales contracts do not give rise to contract assets or contract liabilities.

Performance Obligations

The majority of the Partnership's sales are short-term in nature with a contract term of one year or less. For those contracts, the Partnership has utilized the practical expedient in ASC 606-10-50-14 exempting the Partnership from disclosures of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original duration of one year or less.

For the Partnership's product sales that have a contract term greater than one year, the Partnership has utilized the practical expedient in ASC 606-10-50-14(a), which states the Partnership is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligation is not required.

14. Accrued Liabilities

Accrued liabilities consist of the following at December 31, 2022 and 2021:

	December 31,	
	2022	**2021**
Accrued production expenses	$ 19,846	$ 16,815
Accrued capital expenditures	6,654	541
Accrued severance taxes	4,946	3,511
Accrued ad valorem taxes	2,420	2,211
Other accrued liabilities	262	680
Total accrued liabilities	$ 34,128	$ 23,758

15. Supplemental Cash Flow Information

The statement of cash flows excludes the following non-cash transactions:

- The following restricted share activity (Note 13):
  - No forfeitures in 2022 and 2021 and forfeitures of 364,720 restricted units in 2020

- The payment of in-kind dividends of 37,615 units in 2022, 1,301,862 units in 2021 and 37,615 units in 2020 (Note 13).

- The exchange of 533.63 Series 4 Preferred Units for 747.09 Series 5 Preferred Units in 2021 (Note 11).

- Accrued capital expenditures were $6.7 million at December 31, 2022 and $0.5 million at December 31, 2021.

Interest payments totaled $7.9 million for in 2022, $4.1 million in 2021 and $7.3 million in 2020. State income tax payments totaled $0.5 million in 2022, $0.1 million in 2021 and $0.1 million in 2020.

16. Subsequent Events

We have evaluated subsequent events through the date the financial statements were available to be issued. See Notes 1, 4 and 10 for discussion of 2023 reorganization and public listing.

17. Supplementary Financial Information for Oil and Gas Producing Activities *(Unaudited)*

All of our operations are directly related to oil and gas producing activities located in the United States primarily in the San Juan Basin of New Mexico and Colorado and the Permian Basin of West Texas and New Mexico.

Costs Incurred Related to Oil and Gas Producing Activities

The following table summarizes costs incurred whether such costs are capitalized or expensed for financial reporting purposes for each year:

(in thousands)

	2022	2021	2020
Acquisition of proved properties, net	$ 57,392	$ 181,651	$ 15,138
Acquisition of unproved properties	50	67	307
Development	29,833	8,142	5,520
Asset retirement obligation incurred upon acquisition	3,357	10,741	54,902
Total costs incurred	$ 90,632	$ 200,601	$ 75,867

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors. Proved reserves exclude volumes deliverable to others under production payments or retained interests.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% rate. No provision is included for federal income taxes since our future net cash flows are not subject to taxation. Limited liability companies are subject to the Texas margin tax.

Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. Such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values as of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired (Note 7).

The standardized measure does not represent management’s estimate of our future cash flows or the value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as effected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

Proved Reserves	**Oil (Bbls)**	**Natural Gas Liquids (Bbls)**	**Gas (Mcf)**	**Oil Equivalents (Boe)**
(in thousands)				
December 31, 2019	24,002.0	4,586.2	107,103.4	46,438.8
Extensions, additions and discoveries	19.8	1.5	32.3	26.7
Revisions	(4,067.5)	(2,080.4)	(50,269.3)	(14,526.2)
Production	(940.1)	(860.2)	(22,131.6)	(5,488.9)
Purchase in place	590.6	6,664.1	208,438.1	41,994.4
December 31, 2020	19,604.8	8,311.2	243,172.9	68,444.8
Extensions, additions and discoveries	38.3	14.5	6,048.3	1,060.9
Revisions	2,758.8	7,277.1	152,978.3	35,532.3
Production	(1,033.0)	(1,088.8)	(30,589.7)	(7,220.1)
Purchase in place	27,236.7	3,513.6	7,666.1	32,028.0
December 31, 2021	48,605.6	18,027.6	379,275.9	129,845.9
Extensions, additions and discoveries	943.6	131.0	1,804.9	1,375.4
Revisions	925.3	4,320.1	56,198.3	14,611.7
Production	(2,205.7)	(1,334.3)	(29,556.9)	(8,466.1)
Purchase in place	5,240.4	788.0	155.0	6,054.2
December 31, 2022	53,509.2	21,932.4	407,877.2	143,421.1

Proved Developed Reserves	**Oil (Bbls)**	**Natural Gas Liquids (Bbls)**	**Gas (Mcf)**	**Oil Equivalents (Boe)**
(in thousands)				
December 31, 2019	13,106.5	4,586.2	80,755.3	31,151.9
December 31, 2020	9,787.7	8,311.2	218,396.9	54,498.4
December 31, 2021	30,207.9	17,434.2	353,214.9	106,511.3
December 31, 2022	34,672.0	20,723.6	385,188.6	119,593.7

Proved Undeveloped Reserves	**Oil (Bbls)**	**Natural Gas Liquids (Bbls)**	**Gas (Mcf)**	**Oil Equivalents (Boe)**
(in thousands)				
December 31, 2019	10,895.5	—	26,348.1	15,286.9
December 31, 2020	9,817.1	—	24,776.0	13,946.4
December 31, 2021	18,397.7	593.4	26,061.0	23,334.6
December 31, 2022	18,837.2	1,208.8	22,688.6	23,827.4

In 2022, the 6.1 Mboe of purchases in place represent the reserves acquired primarily from Vendera (5.6 MBoe) and Kaiser Francis (0.4 MBoe). The 1.4 MBoe of extensions, additions and discoveries in proved reserves in 2022 were primarily related to drilling the San Juan Basin and Permian Basin. The 14.6 MBoe of upward revisions in proved of reserves for 2022 were the result of a combination of higher commodity prices (14.9 MBoe) partially offset by changes in the development plan (0.2 MBoe).

In 2021, the 32.0 Mboe of purchases in place represent the reserves acquired from Chevron in November 2021 (24.9 Mboe) and in December 31, 2021 (7.1 Mboe). The 1.1 MBoe of extensions, additions and discoveries in proved reserves in 2021 were primarily related to drilling the San Juan Basin. The 35.5 MBoe of upward revisions in proved of reserves for 2021 were the result of a combination of higher commodity prices (34.9 MBoe) and changes in the development plan (0.6 MBoe).

In 2020, the 42.0 Mboe of purchases in place represent the reserves acquired from Southland Royalty in June 2020. The 14.5 Mboe of downward revisions in proved of reserves for 2020 were the result of a combination of lower commodity prices (17.4 Mboe) partially offset by changes in the development plan and forecast revisions (2.9 Mboe).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves *(in thousands)*	**December 31, 2022**	**December 31, 2021**	**December 31, 2020**
Future cash inflows	$ 7,663,099	$ 4,468,597	$ 1,049,560
Future costs:			
Production	(2,906,249)	(1,988,988)	(531,684)
Development	(414,061)	(365,289)	(297,570)
Future income tax	(7,467)	(4,110)	48
Future net cash flows	4,335,322	2,110,210	220,354
10% annual discount	(2,365,504)	(1,123,593)	(65,916)
Standardized measure	$ 1,969,818	$ 986,617	$ 154,438

Changes in Standardized Measure of Discounted Future Net Cash Flows *(in thousands)*	**For the Year Ended December 31,** **2022**	**2021**	**2020**
Standardized measure, beginning of period	$ 986,617	$ 154,438	$ 315,023
Revisions:			
Prices and costs	745,577	205,842	(261,185)
Quantity estimates	213,687	76,737	(29,789)
Income tax	(1,491)	(1,933)	789
Future development costs	(2,521)	2,715	18,370
Accretion of discount	98,662	15,444	31,502
Production rates and other	(39,947)	42,064	42,303
Net revisions	1,013,967	340,869	(198,010)
Additions and discoveries	25,502	20,272	150
Production	(226,960)	(93,042)	(7,085)
Development costs	29,833	13,973	11,639
Purchases in place	140,859	550,107	32,721
Net change	983,201	832,179	(160,585)
Standardized measure, December 31	$ 1,969,818 (a)	$ 986,617 (b)	$ 154,438 (c)

(a) The December 31, 2022 standardized measure includes a reduction of $248.0 million ($248.4 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2022 includes a liability of $126.5 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.

(b) The December 31, 2021 standardized measure includes a reduction of $213.1 million ($213.6 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2021 includes a liability of $104.5 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.

(c) The December 31, 2020 standardized measure includes a reduction of $201.9 million ($202.3 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2020 includes a liability of $100.7 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.

Price and cost revisions are primarily the net result of changes in prices, based on beginning of year reserve estimates. Quantity estimate revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Average realized oil prices used in the estimation of proved reserves and calculation of the standardized measure were $92.94 for 2022, $64.76 for 2021 and $37.77 for 2020. Average realized natural gas liquids prices were $29.72 for 2022, $19.62 for 2021 and $7.38 for 2020. Average realized gas prices were $4.35 for 2022, $2.31 for 2021 and $1.03 for 2020. We used 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosures

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act as of December 31, 2022. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that as of December 31, 2022, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized, and reported as and when required, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding its required disclosure.

Management’s Report on Internal Control over Financial Reporting

This annual report does not include a report of management’s assessment regarding internal control over financial reporting or an attestation report of the company’s registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in connection with the evaluation required by Rule 13a-15(d) and 15d-15(d) of the Exchange Act that occurred during the quarterly period ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdiction that Prevent Inspections.

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of TXO Energy Partners

We are managed and operated by our general partner, which is managed by the board of directors (the "Board") and executive officers of our general partner. The sole member of our general partner is controlled by the Founders. Our unitholders are not entitled to elect our general partner or its directors or otherwise directly participate in our management or operations. Our general partner owes certain contractual duties to us as well as to its owners.

Our general partner has seven directors, each of whom was appointed by MorningStar Oil & Gas, LLC ("MSOG"), as the sole member of our general partner. Four of our directors are independent as defined under the standards established by the NYSE and the Exchange Act. The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the Board or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to certain transitional relief during the one-year period following consummation of our initial public offering. We have three independent members of the audit committee.

Our operations are conducted through, and our assets are owned by, various subsidiaries. However, we do not have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring personnel or by obtaining services of personnel employed by third parties, but we sometimes refer to these individuals, for drafting convenience only, in this Annual Report on Form 10-K as our employees because they provide services directly to us.

Neither our general partner nor the Founders will receive any management fee or other compensation in connection with our general partner's management of our business, but we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, benefits, bonus, long term incentives and other amounts paid to persons who perform services for us or on our behalf.

In evaluating director candidates, our general partner will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the Board to fulfill their duties.

The following table sets forth certain information regarding the current executive officers and directors of our general partner.

Name	Age	Position
Bob R. Simpson	74	Chief Executive Officer, Chairman and Director
Brent W. Clum	59	President of Business Operations and Chief Financial Officer, Director
Keith A. Hutton	64	President of Production and Development, Director
Scott T. Agosta	58	Chief Accounting Officer
Phillip R. Kevil	72	Director
Rick J. Settle	32	Director
J. Luther King, Jr.	82	Director
William ("Bill") H. Adams III	64	Director

Bob R. Simpson—Chief Executive Officer, Chairman and Director. Bob R. Simpson founded TXO Energy Partners in June 2012 and has served as a Director and the Chairman of the Board since its founding and has served as our Chief Executive Officer since July 2022. Mr. Simpson previously served as the Chairman and a Director of Southland from February 2015 until January 2020. From August 2010 until September of 2020, Mr. Simpson served as Co-Chairman of the Rangers Baseball Express and since September of 2020, he has served as Chair of the Executive Committee. He also served as Chief Executive Officer of XTO (a company he founded) until 2008 and as Chairman of XTO until 2010 when

XTO merged with Exxon for $41 billion in one of the largest transactions in history for an independent oil and gas company. Mr. Simpson attended Baylor University, where he earned a B.B.A. in Accounting magna cum laude and then an M.B.A. He served in the Texas Army National Guard after graduation and then earned his certified public accountant ("CPA") designation.

We believe that Mr. Simpson's extensive industry background, leadership experience on private boards, and deep knowledge of our business make him well suited to serve as a member of our board of directors.

Brent W. Clum—President of Business Operations, Chief Financial Officer and Director. Brent W. Clum has served as our Chief Financial Officer since the founding of TXO Energy Partners in June 2012, and has served as the President of Business Operations and as a Director since July 2022. Mr. Clum served as Chief Financial Officer and Director of Southland from February 2015 until January 2020. Since August 2010, he has served as Chairman of the Finance and Audit Committee of Rangers Baseball Express. He served as Senior Vice President and Treasurer of XTO until the Exxon acquisition. Prior to joining XTO, Mr. Clum worked as a portfolio manager at Luther King Capital Management, served as a Managing Director at Invesco and was an Analyst for T. Rowe Price and Associates. He graduated from Baylor University with a Bachelors in Business Administration in Finance, Accounting and Marketing and from the Harvard Graduate School of Business with a Master's in Business Administration. He is a CPA and a chartered financial analyst ("CFA").

We believe that Mr. Clum's industry experience, his previous leadership positions and finance-related roles, as well as his deep knowledge of our business make him well suited to serve as a member of our board of directors.

Keith A. Hutton—President of Production and Development, Director. Keith A. Hutton has served as our President of Production and Development since July 2022 and as a Director since our founding in June 2012. He previously served as our Chief Executive Officer from our founding in June 2012 until July 2022. Mr. Hutton served as Director of Southland from February 2015 until January 2020. Mr. Hutton also served as Chief Executive Officer and Director of XTO until the time of the Exxon acquisition. He remained a consultant with Exxon until January 2012. Mr. Hutton held various management positions for XTO over his 25 year career and was promoted to CEO in December 2008. Prior to joining XTO Energy in 1987, Mr. Hutton was employed with Sun Oil Company in both the international and domestic divisions for five years. He graduated from Texas A&M University with a B.S. in Petroleum Engineering and was named a Harold Vance Department of Petroleum Engineering Distinguished Graduate in 2009.

We believe that Mr. Hutton's background in the energy industry and his experience as an executive make him well suited to serve as a member of our board of directors.

Scott T. Agosta—Chief Accounting Officer. Scott T. Agosta has served as Chief Accounting Officer and Controller of TXO Energy Partners since its founding in June 2012. He also served as Chief Accounting Officer and Controller of Southland from August 2017 until January 2020. He served as Vice President—Financial Reporting of XTO from February 2005 until the Exxon acquisition in March 2012. Additionally, Mr. Agosta has served as a Board Member of the Junior Achievement of the Chisholm Trail since August 2009. Prior to joining XTO, Mr. Agosta worked as the Manager—Financial Reporting and Analysis at Devon Energy Corporation, served as Manager—Financial Reporting at Albemarle Corporation and was an Audit Manager at KPMG. He graduated from Louisiana State University with a B.B.A in Accounting. He is a CPA.

Phillip R. Kevil—Director. Phillip R. Kevil has served as a Director of TXO Energy Partner since January 2023. He previously served as a Director and as a member of the Audit Committee for XTO from 2004 until 2010. He also served as Vice President – Tax at XTO from 1987 until 1997. Mr. Kevil was responsible for all tax functions for Southland from 1975 until 1986. He graduated from the University of Texas at Arlington with a B.A in Accounting.

We believe that Mr. Kevil's experience in corporate finance and the energy industry, as well has his previous experience as a director and audit committee member of a public company, make him well suited to serve as a member of our board of directors.

Rick J. Settle—Director. Rick J. Settle has served as a Director of TXO Energy Partners since July 2020. Mr. Settle is a Principal at LKCM Headwater Investments, the private equity arm of Luther King Capital Management, and has previously served as a Vice President and Associate since joining the firm in October 2014. Prior to becoming a Principal at LKCM Headwater, Mr. Settle worked as a financial analyst for Citigroup. Mr. Settle also serves on the board of several privately-held companies including Kindthread, a healthcare apparel business, Aquila Environmental, an energy efficiency lighting ESCO, and Heart of Texas Propane, a retail propane distribution business. He graduated from the Texas Christian University with a B.B.A. in Finance, Entrepreneurial Management.

We believe that Mr. Settle's deep knowledge of the energy industry and corporate finance make him well suited to serve as a member of our board of directors.

J. Luther King, Jr.—Director. J. Luther King, Jr. has served as Director of TXO Energy Partners since 2016. He served as Director of Tyler Technologies, Inc. (NYSE: TYL) from May 2004 until May 2021, serving on the Compensation and Audit Committees throughout his tenure at the company. Additionally, he has served as Director of LKCM Funds since February 1994. Mr. King also previously served as Director of Encore Energy Partners LP (Nasdaq: ENP) and as Director of XTO. Over the course of his career, he has served on the boards of several publicly traded companies, three of which were listed on the NYSE. In his position as a director of these companies, Mr. King has served as Chair of both Audit and Compensation Committees. Mr. King currently serves as President of Luther King Capital Management, a position he has held since February 1979. He attended Texas Christian University, where he earned a B.Sc. and then an M.B.A. Mr. King is a CFA and was recognized by CFA Magazine as "Most Inspiring" in the Investment Advisory Profession in 2007. Additionally, Mr. King is a founding member of the Strategic Advisory Board of the CFA Society of Dallas/Fort Worth.

We believe that Mr. King's experience serving on the boards of other public companies, along with his deep knowledge of our business and extensive industry experience, make him well suited to serve as a member of our board of directors.

William ("Bill") H. Adams III—Director. Bill H. Adams has served as Director of TXO Energy Partners since January 2023. He currently also serves as Director of Kimbell Royalty GP, LLC (NYSE: KRP), a position he has held since January 2017. In this position, Mr. Adams has served on the Audit, Compensation and Conflicts Committees of the company. Mr. Adams served as Director of Double B Holdings, LLC from 2012 until 2021. Additionally, Mr. Adams has served as Director of Graham Savings Bank since 2018, of JBN Investments, LLC since 2010, of Back Holdings, LLC since 2007 and of Jabb Associates, Inc. since 1997. Mr. Adams has also held the position of Chairman and has been a principal owner of Texas Appliance Supply, Inc., a wholesale and retail distribution company, since 2007. Prior to its sale to Exxon Mobil Corporation in 2010, he served on the board of directors of XTO Energy Inc., where he chaired the Compensation and the Corporate Governance and Nominating committees. Previously, Mr. Adams had a 25-year career in commercial and energy banking, most recently as Executive Regional President of Texas Bank in Fort Worth, before retiring in 2006. He also served as President of Frost Bank-Arlington. Mr. Adams received a B.B.A. in Finance from Texas Tech University.

We believe that Mr. Adams' strong track record of leading companies, including his participation on the boards of several companies, and his knowledge of the industry, make him well suited to serve as a member of our board of directors.

Southland Bankruptcy

On January 27, 2020, Southland filed a voluntary petition in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). With the approval of the Bankruptcy Court, in May 2020 Southland sold its assets in the San Juan Basin to TXO Energy Partners for $10.2 million. At the time of filing for bankruptcy and the Bankruptcy Court's approval of its plan of reorganization, Bob R. Simpson, Scott T. Agosta, Keith A. Hutton, and Brent W. Clum were acting or former officers of Southland and were affiliates of TXO Energy Partners. As of the date of this Annual Report on Form 10-K, none of these individuals are employed by or affiliated with Southland.

Board of Directors

We are managed and operated by the board of directors and executive officers of our general partner, TXO Energy GP, LLC. The sole member of our general partner is MorningStar Oil & Gas, LLC ("MSOG"), all of the ownership interests of which are owned by the Founders. As the sole member of our general partner, MSOG is entitled under the amended and restated limited liability company agreement of our general partner to appoint all directors of the Board. The number of directors shall be fixed from time to time by MSOG. As of March 28, 2023, the Board consisted of seven persons.

As a limited partnership, we are not required by the rules of the NYSE to seek unitholder approval for the election of any of our directors. In evaluating director candidates, MSOG will assess whether a candidate possesses the integrity,

judgment, knowledge, experience, skills and expertise that are likely to enhance the Board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the Board to fulfill their duties.

Our general partner's directors hold office until the earlier of their death, resignation, retirement, disqualification or removal or until their successors have been duly elected and qualified.

Director Independence

Four directors qualify as "independent" under the listing standards of the NYSE and our governance guidelines. Our Board has affirmatively determined that the directors who qualify as "independent" under the NYSE's listing standards, SEC rules and our governance guidelines are Phillip R. Kevil, Rick J. Settle, J. Luther King, Jr. and Bill H. Adams III.

Board Leadership Structure

Leadership of our general partner's board of directors is vested in a Chairman of the Board. Mr. Bob Simpson currently serves as a Director and the Chairman of the Board, and we have no policy with respect to the separation of the offices of chairman of the Board and chief executive officer. Instead, that relationship is defined and governed by the amended and restated limited liability company agreement of our general partner, which permits the same person to hold both offices.

Board Role in Risk Oversight

Our corporate governance guidelines provide that the Board is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility is largely satisfied by our audit committee, which is responsible for reviewing and discussing with management and our independent registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies. A current copy of the corporate governance guidelines is posted on our investor relations website under the Corporate Governance tab, available at *www.txoenergy.com/investors*.

Committees of the Board of Directors

The Board has an audit committee, a compensation committee, a conflicts committee, and such other committees as the Board shall determine from time to time. The NYSE listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee. However, we have established a compensation committee that will have the responsibilities set forth below.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE listing rules and rules of the SEC. The audit committee assists the Board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee and our management. Rick J. Settle, Phillip R. Kevil and Bill H. Adams III currently serve on the audit committee. Rick J. Settle currently serves as chair of the audit committee. The Board has determined that each member of the audit committee meets the independence requirements of the NYSE and the SEC, as applicable, and that each is financially literate. The Board also has determined that Rick J. Settle has "accounting or related financial management expertise" and constitutes an "audit committee financial expert," in accordance with SEC and NYSE rules and regulations. The audit committee operates under a written charter that satisfies the applicable standards of the SEC and the NYSE. A current copy of the audit committee charter is posted on our investor relations website under the Corporate Governance tab, available at *www.txoenergy.com/investors.*

Conflicts Committee

In accordance with the terms of our partnership agreement, at least two members of the Board will serve on our conflicts committee to review specific matters that may involve conflicts of interest. The members of our conflicts committee cannot be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. In addition, the members of our conflicts committee cannot own any interest in our general partner or its affiliates or any interest in us or our subsidiaries other than common units or awards, if any, under our incentive compensation plan. Rick J. Settle, Phillip R. Kevil and Bill H. Adams III currently serve as members of our conflicts committee. The Board has determined that each member of the conflicts committee meets the independence requirements of the NYSE and the SEC, as applicable.

Compensation Committee

The members of our compensation committee are Phillip R. Kevil, J. Luther King, Jr. and Bill H. Adams III, who also serves as chair of the compensation committee. Each of the members of our compensation committee are independent under the applicable rules and regulations of the NYSE, are a “non-employee director” as defined in Rule 16b-3 promulgated under the Exchange Act and are an “outside director” as that term is defined in Section 162(m) of the Code (Section 162(m)). The compensation committee operates under a written charter that satisfies the applicable standards of the SEC and the NYSE. A current copy of the compensation committee charter is posted on our investor relations website under the Corporate Governance tab, available at *www.txoenergy.com/investors.*

The compensation committee’s responsibilities include:

- annually reviewing and approving corporate goals and objectives relevant to compensation of our chief executive officer and our other executive officers;

- annually reviewing and making recommendations to our board of directors with respect to the compensation of our chief executive officer and determining the compensation for our other executive officers;

- reviewing and making recommendations to our board of directors with respect to director compensation; and

- overseeing and administering our equity incentive plans.

From time to time, our compensation committee may use outside compensation consultants to assist it in analyzing our compensation programs and in determining appropriate levels of compensation and benefits. The compensation committee will review and evaluate, at least annually, the performance of the compensation committee and its members, including compliance by the compensation committee with its charter.

Code of Business Conduct and Ethics

The Board has adopted a Code of Business Conduct and Ethics that applies to all directors, officers and employees of our general partner and its affiliates, including our principal executive officers, principal financial officer, and principal accounting officer. The Code of Business Conduct and Ethics is available on our investor relations website at *www.txoenergy.com/investors* under the Corporate Governance tab. In addition, we intend to post on our website all disclosures that are required by law or the NYSE listing standards concerning any amendments to, or waivers from, any provision of our Code of Business Conduct and Ethics. The information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

Executive Sessions of Independent Directors

In accordance with our Corporate Governance Guidelines, the Board holds executive sessions of independent directors on a regularly scheduled basis but no less than twice per year. If the Chairman of the Board is a member of management or does not otherwise qualify as independent, the independent directors may elect a lead director. The lead director’s responsibilities include, but are not limited to: presiding over all meetings of the Board at which the Chairman of the Board is not present, including any executive sessions of the independent directors; approving Board meeting schedules and agendas; and acting as the liaison between the independent directors and the Chief Executive Officer and

Chairman of the Board. At such times as the Chairman of the Board is an independent director, the Chairman of the Board will serve as lead director. The Board may modify its leadership structure in the future as it deems appropriate.

Communications with Directors

Unitholders and other interested parties wishing to communicate with our Board or with non-management directors may send a written communication addressed to:

TXO Energy Partners, L.P.
400 West, 7th Street,
Fort Worth, Texas 76102
Attention: Secretary

Such communications should specify the intended recipient or recipients.

Item 11. Executive Compensation

General

We do not directly employ any of the persons responsible for managing our business. Our general partner's executive officers manage our business as part of the services provided by our general partner to us under our partnership agreement. Although all of the employees that conduct our business are either employed by our general partner or its subsidiaries, we sometimes refer to these individuals in this Annual Report on Form 10-K as our employees.

All of our general partner's executive officers and other employees necessary to operate our business are employed and compensated by either our general partner or a subsidiary of the general partner, subject to reimbursement by our general partner. The compensation for all of our executive officers will be indirectly paid by us to the extent provided for in the partnership agreement because we will reimburse our general partner for compensation it pays related to management of our business.

Our compensation committee is responsible for reviewing and making recommendations to our board of directors with respect to the compensation of our chief executive officer and determining the compensation of our other executive officers. Our predecessor historically compensated certain of its executive officers primarily with base salary and cash bonuses. However, the compensation committee may consider the compensation structures and levels that they believe will be necessary for executive recruitment and retention for us as a public company.

Emerging Growth Company Status

As an emerging growth company we are exempt from certain requirements related to executive compensation, including the requirements to hold a nonbinding advisory vote on executive compensation and to provide information relating to the ratio of total compensation of our chief executive officer to the median of the annual total compensation of all of our employees, each as required by the Investor Protection and Securities Reform Act of 2010, which is part of the Dodd-Frank Wall Street Reform and Consumer Protection Act. The rules applicable to emerging growth companies require compensation disclosure for any individuals serving as our principal executive officer during the last completed fiscal year and the two most highly compensated executive officers other than our principal executive officer, as well as up to two additional individuals who would have been one of the two most highly compensated executive officers had they remained employed as of the last day of the year. We refer to these officers as our "Named Executive Officers" or "NEOs". Our NEOs for 2022 consist of the following four individuals:

- Bob R. Simpson, our Chief Executive Officer and Chairman of the Board;
- Brent W. Clum, our President of Business Operations, Chief Financial Officer, and Director;
- Keith A. Hutton, our President of Production and Development and Director; and
- Scott T. Agosta, our Chief Accounting Officer.

2022 Summary Compensation Table

The following table sets forth compensation for our NEOs, for the years ended December 31, 2022 and 2021.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)[1]	Value of All Other Compensation ($)[2]	Total Compensation ($)
Bob R. Simpson	2022	—	—	—	—	—
CEO, Chairman, and Director[3]	2021	—	—	—	—	—
Brent W. Clum	2022	262,500	220,000	—	9,150	491,650
President of Business Operations, CFO, and Director	2021	250,000	75,000	2,400,000	8,700	2,733,700
Keith A. Hutton[4]	2022	—	—	—	—	—
President of Production and Development Director	2021	—	—	—	—	—
Scott T. Agosta	2022	280,000	100,000	—	9,150	389,150
Chief Accounting Officer	2021	250,000	50,000	—	8,700	308,700

(1) Amounts reported represent the aggregate grant date fair value of common units awarded to each NEO, calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, Compensation – Stock Compensation, based on the fair market value of a common unit as of the grant date and the number of common units subject to award. The assumptions used in determining the valuation of the unit awards are found in Note 12 to the Consolidated Financial Statements.

(2) The amounts disclosed in this column reflect matching contributions made on behalf of employees under our 401(k) plan.

(3) Mr. Simpson was appointed as Chief Executive Officer in July 2022. Mr. Simpson did not receive any compensation in his capacity as Chief Executive Officer or as Chairman and Director of the Board in 2021 or 2022.

(4) Mr. Hutton was appointed as President of Production and Development in July 2022, prior to which he served as our Chief Executive Officer. Mr. Hutton did not receive any compensation in his capacity as an officer or director in 2021 or 2022.

Narrative to 2022 Summary Compensation Table

Annual Base Salaries

The NEOs receive an annual base salary to provide a fixed component of compensation reflecting the executive's skill set, experience, role and responsibilities. The 2022 annual base salaries for our NEOs were as set forth in the Summary Compensation Table.

2022 Annual Performance Bonus

The NEOs are eligible to receive a discretionary annual cash bonus which was determined by the board of directors. The 2022 annual performance bonuses for our NEOs were as set forth in the Summary Compensation Table.

Other *Elements* of Compensation

Retirement Plan

We maintain a 401(k) retirement savings plan that allows employees to contribute and defer a portion of their wages. Regardless of an employees' decision to participate in the 401(k) plan, we make a non-elective contribution equal to 3% of each employees' wages. Additionally, we have the ability to make a discretionary annual match as determined by the general partner. Effective January 1, 2023, we began matching employee contributions up to 7% of wages, subject to annual dollar maximums established by the federal government and plan limitations. We believe that providing a vehicle for tax-deferred retirement savings though our 401(k) plan adds to the overall desirability of our executive compensation package and further incentivizes our employees, including our NEOs, in accordance with our compensation policies.

The employer matching contributions to the 401(k) retirement savings plan on behalf of our participating NEOs are set forth above in the 2022 Summary Compensation Table in the column titled “Value of All Other Compensation.”

We do not maintain, sponsor, contribute to or otherwise have any liability with respect to any single or multiemployer defined benefit pension plan or nonqualified deferred compensation plan.

Long-Term Incentive Plan

We have adopted the TXO Energy Partners, L.P. 2023 Long-Term Incentive Plan (the "LTIP") under which our general partner may issue long-term equity based awards to directors, officers and employees of our general partner or its affiliates, or to any consultants, affiliates of our general partner or other individuals who perform services for us. These awards will be intended to compensate the recipients thereof based on the performance of our common units and their continued service during the vesting period, as well as to align their long-term interests with those of our unitholders. We will be responsible for the cost of awards granted under the LTIP and all determinations with respect to awards to be made under the LTIP will be made by the board of directors of our general partner or any committee thereof that may be established for such purpose or by any delegate of the board of directors or such committee, subject to applicable law, which we refer to as the plan administrator. The Compensation Committee of the board of directors of our general partner has been designated as the plan administrator. The following description reflects the terms of the LTIP.

General

The LTIP provides for the grant, from time to time at the discretion of the board of directors of our general partner or any delegate thereof, subject to applicable law, of cash awards, unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. The purpose of awards under the LTIP is to provide additional incentive compensation to individuals providing services to us, and to align the economic interests of such individuals with the interests of our unitholders. The LTIP limits the number of units that may be delivered pursuant to vested awards to common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units subject to awards that are cancelled, forfeited, withheld to satisfy exercise prices or tax withholding obligations or otherwise terminated without delivery of the common units will be available for delivery pursuant to other awards.

Cash Awards

The plan administrator of the LTIP, in its discretion, may grant cash awards, either as standalone awards or in tandem with other awards. A cash award is an award denominated in cash.

Restricted Units and Phantom Units

A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the plan administrator, cash equal to the fair market value of a common unit. The plan administrator of the LTIP may make grants of restricted units and phantom units under the LTIP that contain such terms, consistent with the LTIP, as the plan administrator may determine are appropriate, including the period over which restricted units or phantom units will vest. The plan administrator of the LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change of control (as defined in the LTIP) or as otherwise described in an award agreement.

Distributions made by us with respect to awards of restricted units may be subject to the same vesting requirements as the restricted units.

Distribution Equivalent Rights

The plan administrator of the LTIP, in its discretion, may also grant distribution equivalent rights, either as standalone awards or in tandem with other awards. Distribution equivalent rights are rights to receive an amount in cash, restricted units or phantom units equal to all or a portion of the cash distributions made on units during the period an award remains outstanding.

Unit Options and Unit Appreciation Rights

The LTIP may also permit the grant of options covering common units. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common units over a specified exercise price, either in cash or in common units. Unit options and unit appreciation rights may be granted to such eligible individuals and with such terms as the plan administrator of the LTIP may determine, consistent with the LTIP; however, a unit option or unit appreciation right must have an exercise price equal to at least the fair market value of a common unit on the date of grant.

Unit Awards

Awards covering common units may be granted under the LTIP with such terms and conditions, including restrictions on transferability, as the plan administrator of the LTIP may establish.

Profits Interest Units

Awards granted to grantees who are partners, or granted to grantees in anticipation of the grantee becoming a partner or granted as otherwise determined by the plan administrator, may consist of profits interest units. The plan administrator will determine the applicable vesting dates, conditions to vesting and restrictions on transferability and any other restrictions for profits interest awards.

Other Unit-Based Awards

The LTIP may also permit the grant of “other unit-based awards,” which are awards that, in whole or in part, are valued or based on or related to the value of a common unit. The vesting of another unit-based award may be based on a participant’s continued service, the achievement of performance criteria or other measures. On vesting or on a deferred basis upon specified future dates or events, another unit-based award may be paid in cash and/or in units (including restricted units) or any combination thereof as the plan administrator of the LTIP may determine.

Source of Common Units

Common units to be delivered with respect to awards may be newly-issued units, common units acquired by us or our general partner in the open market, common units already owned by our general partner or us, common units acquired by our general partner directly from us or any other person or any combination of the foregoing.

Anti-Dilution Adjustments and Change in Control

If an “equity restructuring” event occurs that could result in an additional compensation expense under applicable accounting standards if adjustments to awards under the LTIP with respect to such event were discretionary, the plan administrator of the LTIP will equitably adjust the number and type of units covered by each outstanding award and the terms and conditions of such award to equitably reflect the restructuring event, and the plan administrator will adjust the number and type of units with respect to which future awards may be granted under the LTIP. With respect to other similar events, including, for example, a combination or exchange of units, a merger or consolidation or an extraordinary distribution of our assets to unitholders, that would not result in an accounting charge if adjustment to awards were discretionary, the plan administrator of the LTIP shall have discretion to adjust awards in the manner it deems appropriate and to make equitable adjustments, if any, with respect to the number of units available under the LTIP and the kind of units or other securities available for grant under the LTIP. Furthermore, upon any such event, including a change in control of us or our general partner, or a change in any law or regulation affecting the LTIP or outstanding awards or any relevant change in accounting principles, the plan administrator of the LTIP will generally have discretion to (i) accelerate the time of exercisability or vesting or payment of an award, (ii) require awards to be surrendered in exchange for a cash payment or substitute other rights or property for the award, (iii) provide for the award to assumed by a successor or one of its affiliates, with appropriate adjustments thereto, (iv) cancel unvested awards without payment or (v) make other adjustments to awards as the plan administrator deems appropriate to reflect the applicable transaction or event.

Termination of Service

The consequences of the termination of a grantee’s membership on the board of directors of our general partner or other service arrangement will generally be determined by the plan administrator in the terms of the relevant award agreement.

Amendment or Termination of Long-Term Incentive Plan

The plan administrator of the LTIP, at its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The plan administrator of the LTIP also has the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP, provided that no change in any outstanding award may be made that would materially impair the vested rights of the participant without the consent of the affected participant or result in taxation to the participant under Section 409A of the Internal Revenue Code.

Grants in Connection with the Initial Public Offering

In connection with the closing of our initial public offering, we made awards of 545,000 phantom units with distribution equivalent rights as long-term incentive awards pursuant to the LTIP. These phantom units will vest in one-third increments on each of the first three anniversaries of the pricing date of our initial public offering for the officers and key employees and will fully vest on the one-year anniversary of the grant for the non-employee directors provided that the recipient remains employed or a member of the Board, as applicable, through the anniversary date, and will be settled in common units as soon as reasonably practicable after the vesting date. Distribution equivalents will be paid to holders of outstanding phantom units, including unvested phantom units, on the next payroll dates after the distribution is paid to holders of common units.

All outstanding and unvested phantom units will vest in the event that the officer's employment is terminated without "cause" or by the officer for "good reason" (each as defined in the LTIP and the award agreement) within the two year period following a "change in control" (as defined in the LTIP). Similarly, all outstanding and unvested phantom units held by a director will vest in the event of a change of control. Additionally, the Compensation Committee may determine, in its discretion, to vest unvested phantom units in the event that the officer's employment is terminated for reasons other than "cause" or the director ceases to be a member of the Board as a result of a termination of "service" (as defined in the LTIP).

We have approved grants in the following amounts in connection with the closing of our initial public offering: 50,000 units to each of Mr. Clum and Mr. Agosta. In addition, we made grants of 445,000 units to our directors and certain key employees.

Outstanding Equity Awards at 2022 Year-End

No NEO held an outstanding equity award as of December 31, 2022.

Employment Contracts, Termination of Employment, Change-in-Control Arrangements

We currently do not have any employment agreements or other plans or arrangements with our executive officers that would result in payments to be made by us to an NEO upon the resignation, retirement or any other termination of an NEO's employment or upon a change in control.

Compensation of Directors

Officers or employees of our general partner or its affiliates who also serve as directors will not receive additional compensation for their service as a director of our general partner. The non-employee director compensation program consists of annual equity-based awards granted under the LTIP having a value as of the grant date of approximately $60,000 and an additional $30,000 in equity-based award for service as the chair of a committee of the board of directors. Initial awards were made to our non-employee directors in connection with the closing of the initial public offering.

Non-employee directors will also receive reimbursement for out-of-pocket expenses they incur in connection with attending meetings of the board of directors or its committees. Each director will be indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law.

Item 12. Security Ownership of Certain Beneficial Owner and Management and Related Unitholder Matters

The following table sets forth certain information regarding the beneficial ownership of our common units by:

- beneficial owners of more than 5% of our common units;

- each named executive officer of our general partner; and
- all directors and executive officers of our general partner as a group.

The percentage of units beneficially owned is based on 30,750,000 common units outstanding as of March 15, 2023.

Name of Beneficial Owner(1)	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned
5% Unitholders:		
Global Endowment Management, LP(2)	4,713,962	15 %
Luther King Capital Management(3)	3,298,474	11 %
Named Executive Officers and Directors		
Bob R. Simpson	4,123,110	13 %
Brent W. Clum	329,406	1 %
Keith A. Hutton	2,942,215	10 %
Scott T. Agosta	108,462	*
Phillip R. Kevil	12,584	*
Rick J. Settle	16,216	*
J. Luther King, Jr.(3)	3,298,474	11 %
Bill H. Adams III	58,784	*
All executive officers and directors as a group (8 persons)	10,889,251	35 %

* Represents less than 1%

(1) Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Each of the holders listed has sole voting and investment power with respect to the common units beneficially owned by the holder unless noted otherwise, subject to community property laws where applicable. Unless otherwise noted, the address for each beneficial owner listed below is 400 W 7th St., Fort Worth, TX 76102.

(2) Represents (i) 1,670,731 common units held by GEF-DTOE, Inc. and (ii) 3,043,232 common units held by GEF-PUE, LP. Global Endowment Management, LP controls the investment decisions of each of GEF-DTOE, Inc. and GEF-PUE, LP, and J. Porter Durham, Jr. has management control over Global Endowment Management, LP and accordingly may be deemed to share beneficial ownership of the common units held by each of GEF-DTOE, Inc. and GEF-PUE, LP. J. Porter Durham, Jr. disclaims beneficial ownership of such common units. The principal address for each of the above referenced entities is c/o Global Endowment Management, LP 224 W. Tremont Ave. Charlotte, NC 28203.

(3) Represents (i) 1,189,400 common units held by LKCM Investment Partnership, L.P, and (ii) 1,372,130 common units held by PDLP Morningstar, LLC, a wholly owned subsidiary of LKCM Private Discipline Master Fund, SPC.

LKCM Investment Partnership GP, LLC is the general partner of LKCM Investment Partnership, L.P., and J. Luther King, Jr. serves as the President and has voting and investment power over the securities held by LKCM Investment Partnership GP, LLC. LKCM Private Discipline Management, L.P. is the sole holder of management shares of LKCM Private Discipline Master Fund, SPC and J. Luther King has voting and investment power over the securities held by LKCM Private Discipline Management L.P.

Accordingly, J. Luther King may be deemed to share beneficial ownership of the common units held by each of LKCM Investment Partnership, L.P. and PDLP Morningstar, J. Luther King disclaims beneficial ownership of such common units. The principal address for each of the above referenced entities is 301 Commerce Street, Suite 1600, Fort Worth, Texas 76102.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The Founders own 8,028,129 common units representing an approximate 26% limited partner interest in us, and MSOG, which is owned by the Founders, own and control our general partner. The Founders, who own MSOG, indirectly appoint all of the directors of our general partner, which owns a non-economic general partner interest in us. These percentages do not reflect any common units that may be issued under the long-term incentive plan.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, were not the result of arm's length negotiations.

Operational Stage

Distributions of available cash to affiliates of our general partner	We make cash distributions to our unitholders, including affiliates of our general partner, pro rata.
	The affiliates of our general partner own 11,572,649 common units, representing approximately 38% of our outstanding common units and would receive a pro rata percentage of the cash distributions that we distribute in respect thereof.
Payments to our general partner and its affiliates	Our general partner will not receive a management fee or other compensation for its management of our partnership, but we will reimburse our general partner and its affiliates for costs and expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its non-economic general partner interest will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner with respect to any common units or other units then held by our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Affiliates in Connection with the Reorganization Transactions

In connection with the closing of our initial public offering, we, our general partner and its affiliates entered into the various documents and agreements that effected the Reorganization Transactions. These agreements were negotiated among affiliated parties and, consequently, are not the result of arm's length negotiations. All of the transaction expenses incurred in connection with these transactions were paid from the proceeds of our initial public offering.

Contribution Agreement

In connection with the closing of our initial public offering, each of our existing owners contributed all of their outstanding equity interests in the partnership to a newly formed parent company, MorningStar Partners II, L.P., or MSP II, in exchange for equity interests in MSP II that are identical to the equity interests owned in the partnership. Following this contribution and immediately prior to the initial public offering, all of our equity interests were held by MSP II.

Other Transactions with Related Persons

We occupy a building owned by MorningStar Capital LLC, a limited liability company owned by Mr. Simpson, our Chief Executive Officer and the Chairman of the Board. In lieu of paying rent, we paid property taxes and paid for repairs and maintenance on behalf of MorningStar Capital LLC in the amount of $0.9 million in 2022 and $0.9 million in 2021.

Procedures for Review, Approval or Ratification of Transactions with Related Persons

The Board has adopted policies for the review, approval and ratification of transactions with related persons. The Board has adopted a written code of business conduct and ethics, under which a director would be expected to bring to the attention of the chief executive officer or the Board any conflict or potential conflict of interest that may arise between the director in his or her personal capacity or any affiliate of the director in his or her personal capacity, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the Board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the Board in accordance with the provisions of our partnership agreement. At the discretion of the Board in light of the circumstances, the resolution may be determined by the Board in its entirety, by the conflicts committee of the Board or by approval of our unitholders (other than the general partner and its affiliates).

Under our code of business conduct, any executive officer will be required to avoid personal conflicts of interest unless approved by the Board.

The code of business conduct and ethics described above was adopted in connection with the closing of our initial public offering, and as a result, the transactions described above were not reviewed according to such procedures.

Item 14. Principal Accounting Fees and Services

The following table sets forth the aggregate fees billed by KPMG LLP for the fiscal years ended December 31, 2022 and December 31, 2021:

	2022	2021
Audit Fees (1)	$ 946,817	$ 272,619
Audit Related Fees	85,000	—
Tax Fees (2)	398,235	119,000
All Other Fees	—	—
Total	$ 1,430,052	$ 391,619

(1) Audit Fees include fees for work on the S-1 and related comfort letters.

(2) Tax fees include fees for tax compliance.

Policy for Approval of Audit and Non-Audit Services

The audit committee, or the chair of the audit committee, must pre-approve any audit and non-audit services and tax services and related fees and the terms thereof provided by the independent auditor, unless the engagement is entered into pursuant to appropriate preapproval policies established by the audit committee or if such service falls within available exceptions under SEC rules. All services and fees that occurred after our initial public offering were reviewed and approved by the audit committee before the respective services were rendered.

Part IV

Item 15. Exhibits, Financial Statement Schedules

Exhibit Number	Description
3.1	Amended and Restated Certificate of Limited Partnership of TXO Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed on January 31, 2023)
3.2	Seventh Amended and Restated Agreement of Limited Partnership of TXO Energy Partners, L.P. (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K filed on January 31, 2023)
3.3	Certificate of Formation of TXO Energy GP, LLC (incorporated by reference to Exhibit 3.3 to the Company's Registration Statement on Form S-1/A filed on January 18, 2023)
3.4*	Amended and Restated Limited Liability Company Agreement of TXO Energy GP, LLC, dated as of January 31, 2023
4.1*	Description of Common Units
10.1#	Credit Agreement, among MorningStar Partners, L.P., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent, dated November 1, 2021 (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed on January 18, 2023)
10.2#	Amendment No. 1 to the Credit Agreement and Borrowing Base Agreement (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1/A filed on January 18, 2023)
10.3	TXO Energy GP, LLC 2023 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed on January 31, 2023)
10.4	Form of 2023 Long-Term Incentive Plan Phantom Unit Agreement (Directors) (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K filed on January 31, 2023)
10.5	Form of 2023 Long-Term Incentive Plan Phantom Unit Agreement (Executives) (incorporated by reference to Exhibit 10.5 to Current Report on Form 8-K filed on January 31, 2023)
10.6#^	Limited Liability Company Agreement of Cross Timbers Energy, LLC, dated as of June 13, 2013, by and among XTO Energy Inc., XH LLC, HHE Energy Company and MorningStar Partners, L.P. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed on January 18, 2023)
10.7	Contribution and Exchange Agreement, dated January 31, 2023, by and among TXO Energy Partners, L.P., MorningStar Oil & Gas, LLC, MorningStar Partners II, L.P. and the Limited Partners party thereto (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on January 31, 2023)
10.8	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on January 31, 2023)
21.1*	List of Subsidiaries of TXO Energy Partners, L.P.
23.1*	Consent of Cawley, Gillespie & Associates
31.1*	Certification of Chief Executive Officer pursuant to Exchange Act Rule 13a-14(a) and Rule 15d-14(a)
31.2*	Certification of Chief Financial Officer pursuant to Exchange Act Rule 13a-14(a) and Rule 15d-14(a)
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.1*	Report of Cawley, Gillespie & Associates of reserves as of December 31, 2022

*   Filed herewith.
**   Furnished herewith.
#   The schedules and exhibits to this agreement have been omitted pursuant to Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule and/or exhibit will be furnished to the SEC upon request.
^   Portions of this exhibit have been redacted pursuant to Item 601(b)(10)(iv) of Regulation S-K.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1933, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Fort Worth, State of Texas, on March 31, 2023.

TXO Energy Partners, L.P.

By: TXO Energy GP, LLC, its general partner

By: /s/ Bob R. Simpson
Name: Bob R. Simpson
Title: Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, as amended, this report has been signed below by the following persons in the capacities and the dates indicated.

Name	Title	Date
/s/ Bob R. Simpson Bob R. Simpson	Chief Executive Officer and Director (principal executive officer)	March 31, 2023
/s/ Brent W. Clum Brent W. Clum	President of Business Operations, Chief Financial Officer and Director (principal financial officer)	March 31, 2023
/s/ Scott T. Agosta Scott T. Agosta	Chief Accounting Officer (principal accounting officer)	March 31, 2023
/s/ Phillip R. Kevil Phillip R. Kevil	Director	March 31, 2023
/s/ Keith A. Hutton Keith A. Hutton	Director	March 31, 2023
/s/ Rick J. Settle Rick J. Settle	Director	March 31, 2023
/s/ J. Luther King, Jr. J. Luther King, Jr.	Director	March 31, 2023
/s/ William H. Adams III William H. Adams III	Director	March 31, 2023