As confidentially submitted to the U.S. Securities and Exchange Commission on August 30, 2023.
This draft registration statement has not been filed, publicly or otherwise, with the U.S. Securities and Exchange Commission and all information contained herein remains strictly confidential.

Registration No. 333-

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

Confidential Draft Submission No. 2
to
Form S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

Mach Natural Resources LP

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**93-1757616**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

14201 Wireless Way, Suite 300
Oklahoma City, Oklahoma 73134
(405) 252-8100
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Tom L. Ward
Chief Executive Officer
14201 Wireless Way, Suite 300
Oklahoma City, Oklahoma 73134
(405) 252-8100
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Julian J. Seiguer, P.C. **Michael W. Rigdon, P.C.** **Kirkland & Ellis LLP** **609 Main Street, Suite 4700** **Houston, Texas 77002** **(713) 836-3600**	**Joshua Davidson** **Douglas V. Getten** **Baker Botts L.L.P.** **910 Louisiana Street** **Houston, Texas 77002** **(713) 229-1234**

Approximate date of commencement of proposed sale of the securities to the public:
As soon as practicable after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box: ☐

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act. ☐

The registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment that specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until this Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

SUBJECT TO COMPLETION, DATED , 2023

PRELIMINARY PROSPECTUS

Mach Natural Resources LP

Common Units
Representing Limited Partner Interests

Mach Natural Resources LP is a Delaware limited partnership focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas. This is the initial public offering of the common units of Mach Natural Resources LP. We are offering common units representing limited partner interests. No public market currently exists for our common units. We expect the initial public offering price to be between $ and $ per common unit. We intend to apply to list our common units on the New York Stock Exchange, under the symbol "MNRE." We are an "emerging growth company" as that term is used in the Jumpstart Our Business Startups Act.

Investing in our common units involves risks. See "Risk Factors" beginning on page 26 of this prospectus.

These risks include the following:

- We may not have sufficient available cash to pay any quarterly distribution on our common units following the payment of expenses, funding of development costs and establishment of cash reserves.
- Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, results of operations, liquidity, ability to meet our financial commitments, ability to make our planned capital expenditures and our cash available for distribution.
- Unless we replace our produced reserves with acquired or developed new reserves, our reserves and production will decline, which would adversely affect our future cash flows, results of operations and cash available for distribution.
- Our operations are subject to stringent environmental laws and regulations that may affect our drilling and production operations and expose us to significant costs and liabilities that could exceed current expectations.
- 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 unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, which could reduce the price at which our common units will trade.
- Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.
- 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 U.S. 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.

PRICE $ PER COMMON UNIT

	Per Common Unit	Total
Public offering price	$	$
Underwriting discount[(1)]	$	$
Proceeds, before expenses	$	$

(1) Includes an aggregate structuring fee equal to % of the gross proceeds of this offering payable to Stifel, Nicolaus & Company, Incorporated and Raymond James & Associates, Inc. Please read "Underwriting."

We have granted the underwriters a 30-day option to purchase up to an additional common units on the same terms and conditions as set forth above if the underwriters sell more than common units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units on or about , 2023.

Joint Book-Running Managers

Stifel	**Raymond James**

, 2023

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Neither we nor the underwriters have authorized anyone to provide you with any information or to make any representations other than those contained in this prospectus. We and the underwriters take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since such dates. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted.

Until , 2023 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. Please read "Risk Factors" and "Forward-Looking Statements."

INDUSTRY AND MARKET DATA

The market data and certain other statistical information included in this prospectus are based on a variety of sources, including independent industry publications, government publications and other published independent sources. Some data is also based on our good faith estimates, which have been derived from management's knowledge and experience in the industry in which we operate. Although we have not independently verified the accuracy or completeness of the third-party information included in this prospectus, based on management's knowledge and experience, we believe that these third-party sources are reliable and that the third-party information included in this prospectus or in our estimates is accurate and complete. While we are not aware of any misstatements regarding the market, industry or similar data presented herein, such data involves risks and uncertainties and is subject to change based on various factors, including those discussed under the headings "Forward-Looking Statements" and "Risk Factors" in this prospectus.

TRADEMARKS AND TRADE NAMES

We own or have rights to various trademarks, service marks and trade names that we use in connection with the operation of our business. This prospectus may also contain trademarks, service marks and trade names of third parties, which are the property of their respective owners. Our use or display of third parties' trademarks, service marks, trade names or products in this prospectus is not intended to, and does not imply a relationship with, or endorsement or sponsorship by us. Solely for convenience, the trademarks, service marks and trade names referred to in this prospectus may appear without the ®, ™ or ℠ symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the right of the applicable licensor to these trademarks, service marks and trade names.

BASIS OF PRESENTATION

Unless otherwise indicated, the historical financial information presented in this prospectus is that of BCE-Mach III LLC ("BCE-Mach III" or "predecessor"), a Delaware limited liability company, our predecessor for accounting purposes. The historical financial information of BCE-Mach LLC, a Delaware limited liability company, and BCE-Mach II LLC, a Delaware limited liability company, is also included herein as indicated.

This prospectus contains unaudited pro forma financial information, which presents certain financial information and operating data of our predecessor, BCE-Mach LLC and BCE-Mach II LLC on a pro forma combined basis to give effect to the initial public offering and the use of proceeds therefrom and the Reorganization Transactions as if they had occurred at the beginning of the periods presented. The production, reserve, acreage, well count, drilling locations, and other historical data in this prospectus are presented on a pro forma combined basis as if the Reorganization Transactions had occurred unless otherwise indicated.

Though the entities to be contributed in connection with the initial public offering and Reorganization Transactions have a high degree of common ownership, no individual or entity controls any of the entities and therefore the Reorganization Transactions are not accounted for as common control transactions.

Unless another date is specified, all production, reserve, acreage, well count and drilling location data presented in this prospectus is as of June 30, 2023.

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. Because this is a summary, it may not contain all of the information that may be important to you and to your investment decision. The following summary is qualified in its entirety by the more detailed information and financial statements and notes thereto included elsewhere in this prospectus. You should read the entire prospectus carefully and should consider, among other things, the matters set forth in "Risk Factors," "Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical and unaudited pro forma consolidated financial statements and the related notes to each of those financial statements included elsewhere in this prospectus before deciding to invest in our common units. Unless otherwise indicated, the financial and operating information as well as the estimated proved and probable reserve information presented in this prospectus gives pro forma effect to the initial public offering and the use of proceeds therefrom and the Reorganization Transactions described herein and presents the data of the Mach Companies on a combined basis.

The information presented in this prospectus assumes (i) an initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover of this prospectus) and (ii) that the underwriters do not exercise their option to purchase up to an additional common units, unless otherwise indicated. As used in this prospectus, the term "our general partner" refers to Mach Natural Resources GP LLC, a Delaware limited liability company, and the terms "Mach Natural Resources," "partnership," the "Company," "we," "our," "us" or similar terms refer to Mach Natural Resources LP, a Delaware limited partnership, and its subsidiaries. We include a glossary of some of the oil and natural gas terms and other terms used in this prospectus in *Appendix B**. Our estimated proved and probable reserve information included in this prospectus is based on reports prepared by Cawley, Gillespie & Associates, Inc., our independent reserve engineers.*

Our Company

We are an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas. Our experienced management team, led by industry veteran Tom L. Ward, possesses deep operational and industry experience, particularly in Oklahoma and the Anadarko Basin. We leverage our extensive experience to identify the most attractive exploitation and development opportunities and optimize the production of current wells, efficiently drill our existing inventory of undeveloped locations and identify attractive low-risk acquisition opportunities.

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 lower decline nature of our Legacy Producing Assets (as defined below) and large inventory of horizontal drilling locations with average royalty burdens of less than 25%, coupled with our lower cash operating costs and owned midstream infrastructure, will support our ability to make cash distributions to our unitholders. We expect to maintain a conservative capital structure with the long-term goal of remaining substantially debt free. 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 commodity prices. Any such variations may be significant, and as a result, we may pay limited or even no cash distributions to our unitholders.

We seek to maximize cash distributions to unitholders through a combination of the development of our existing properties, primarily using our cash flow from operating activities, and the acquisition of producing properties. Our current acreage position in the Anadarko Basin is characterized as oil-rich with considerable natural gas content, notable historical production, low decline rates and average royalty burdens of less than 25%. Through a series of acquisitions since our inception, we have accumulated an acreage position consisting of approximately 936,000 net acres, of which 99% is held by production, and over 2,000 identified horizontal drilling locations, of which more than 750 of these are located in the Oswego formation, a prolific reservoir in north-central Oklahoma. We consider our large inventory of horizontal drilling locations to be low-risk based on information gained from the large number of existing wells in the area, industry activity surrounding our acreage, and the consistent and predictable geology surrounding our positions. We believe the combination of our large inventory of low-risk drilling locations with the low decline production profile of our Legacy Producing Assets leads to a sustainable production profile.

We focus on controlling costs and maintaining financial discipline, which enables us to prudently develop our assets while generating significant cash available for distribution. Our strategy is to enhance existing production and reduce costs by right-sizing field operations to cost-effectively extract oil and natural gas from producing reservoirs Our culture of cost control and production optimization has resulted in substantially lower cash operating costs than our peers.

We believe a key competitive advantage that we have over other operators is that we own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure. Our midstream assets enhance the value of our properties by allowing us to optimize pricing, increase flow assurance and eliminate third-party costs and inefficiencies. In addition, our owned midstream systems generate third-party revenue, which effectively reduces the cost of operating our midstream assets and reduces our average breakeven costs compared to other operators. We believe the Anadarko Basin is uniquely positioned with legacy takeaway pipeline infrastructure enabling our oil, natural gas and NGLs to be easily transported to premium markets, such as Cushing, Oklahoma.

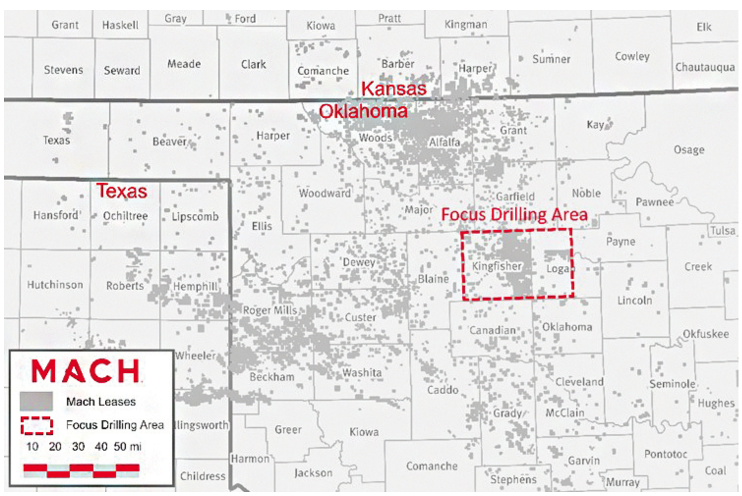
Our Properties

Our assets are located throughout Western Oklahoma, Southern Kansas and the panhandle of Texas and consist of approximately 4,500 gross operated PDP wells. We define our Focus Drilling Area assets as all of our horizontal properties that are located in Kingfisher and Logan Counties, Oklahoma, which we define as the Focus Drilling Area, and we define our “Legacy Producing Assets” as all of our legacy producing properties which are not in the Focus Drilling Area, as shown in the chart below. Based on our reserve report as of June 30, 2023, 57% of our production is attributable to our Legacy Producing Assets, which have an average expected annual decline rate of approximately 15%. Our wells are located almost exclusively in the Anadarko Basin, which has a more predictable production profile compared to less mature basins. Our production benefits from both the diversity of our well vintage and the lack of concentration in any specific sub-area. Within our large and diversified PDP base, no single well accounts for more than 1% of our PDP PV-10.

Within our operating areas, our assets are prospective for multiple formations, most notably the Oswego, Meramec/Osage and Mississippi Lime formations. Our experience in the Anadarko Basin and these formations allows us to generate significant cash available for distribution from these low declining assets in a variety of commodity price environments.

In addition to our portfolio of producing wells, our properties include over 2,000 identified horizontal drilling locations that we believe will allow us to maintain our production and support future cash distributions to our unitholders.

Additionally, we own a portfolio of midstream assets which support our leases. As of June 30, 2023, approximately 75% of our operated PDP reserves (and approximately 66% of our total PDP reserves) are supported by Company-owned midstream infrastructure.



The following table presents our historical estimated oil, natural gas and NGL proved reserves as of June 30, 2023.

	Estimated Proved Reserves as of June 30, 2023		
	Proved Developed Reserves[1]	**Proved Reserves**[1]	**Estimated Probable Reserves as of June 30, 2023**[1][2]
Oil (MBbl)	40,876	53,029	72,868
Natural gas (MMcf)	782,727	811,507	373,477
NGLs (MBbl)	50,190	50,911	19,576
Total equivalent (MBoe)[3]	221,520	239,191	154,690
PV-10 (in millions)[4]	$ 2,131	$ 2,435	$ 1,039
Standardized Measure (in millions)[5]	$ 2,131	$ 2,435	—

(1) Our estimated net proved and probable reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. For more information on the prices used, see "— Summary of Reserve, Production and Operating Data — Summary of Reserves."

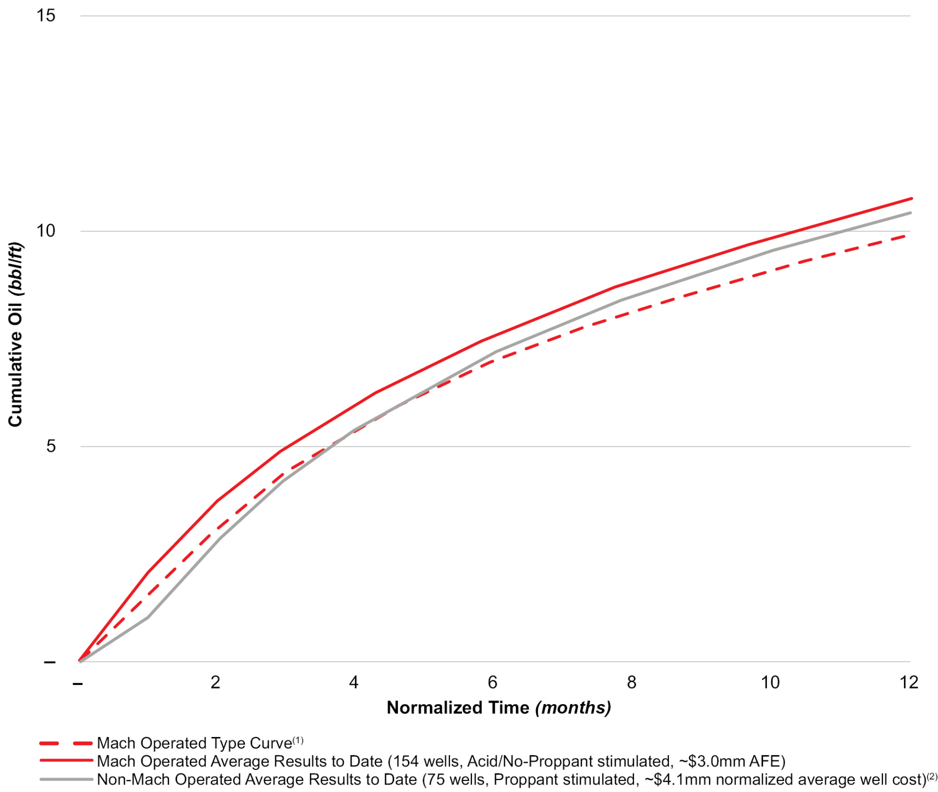
(2) Estimates of probable reserves, and the future cash flows related to such estimates, are inherently imprecise and are more uncertain than estimates of proved reserves and the future cash flows related to such estimates but have not been adjusted for risk due to such uncertainty. Therefore, estimates of probable reserves and the future cash flows related to such estimates may not be comparable to estimates of proved reserves and the future cash flows related to such estimates and should not be summed arithmetically with estimates of proved reserves and the future cash flows related to such estimates. For more information regarding the presentation of probable reserves, see "Business and Properties — Our Operations — Preparation of Reserve Estimates."

(3) Presented on an oil-equivalent basis using a conversion of six thousand cubic feet of natural gas to one stock tank barrel of oil. This conversion is based on energy equivalence and not on price or value equivalence.

(4) For more information on how we calculate PV-10 and a reconciliation of proved reserves PV-10 to its nearest GAAP measure, see "— Summary of Reserve, Production and Operating Data — Summary of Reserves" and "— Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure." With respect to PV-10 calculated as of an interim date, it is not practicable to calculate the taxes for the related interim period because GAAP does not provide for disclosure of Standardized Measure on an interim basis.

(5) For more information on how we calculate Standardized Measure of proved reserves, see "— Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure."

Our near-term drilling program is focused on horizontal development in Kingfisher and Logan Counties, Oklahoma. The two primary, productive formations in this area are the Oswego and Meramec/Osage. The Oswego is the most oil rich and economic formation within our inventory. In the early stages of the Oswego horizontal development, a mixture of standard completion fluids and proppant were utilized in the stimulation. We have successfully further lowered our well costs to $3.0 million per well in the Oswego by using drilling efficiencies and utilizing acid in lieu of proppant within the stimulation. As observed in the chart below, the 154 acid-only stimulated wells that we drilled are performing comparably to the proppant-stimulated 75 Oswego wells producing in Kingfisher County, Oklahoma. The below illustrates the average oil production results from the Oswego as of August 2023:



(1) Based on Management's estimates.

(2) Data and analytics derived from Enverus Core. Includes all offset horizontal wells drilled in Oswego formation with reported proppant loading. Normalized to 5,121 feet.

In addition to the Oswego, there have been over 775 wells in the Meramec/Osage formations drilled and over 1,850 wells in the Mississippi Lime formation drilled on our acreage. Our assets have extensive production histories and high drilling success rates. Accordingly, we believe our acreage has been significantly delineated by our own drilling success and by the success of offset operators.

The below table summarizes our identified horizontal drilling locations as of June30, 2023.

	Identified Horizontal Drilling Locations[(1)(2)]			
Target Horizontal Zones	**Focus Drilling Area Operated**	**Focus Drilling Area Non-Operated**	**Legacy Producing Assets**	**Total**
Oswego	437	314	0	751
Meramec/Osage	265	228	0	493
Mississippi Lime	0	0	778	778
Total Horizontal Locations	702	542	778	2,022
Average Working Interest	82.6%	16.4%	29.7%	44.5%
Average Net Revenue Interest	69.0%	14.1%	24.0%	37.0%

(1) "Business and Properties — Our Operations" contains a description of our methodology used to determine our drilling locations.

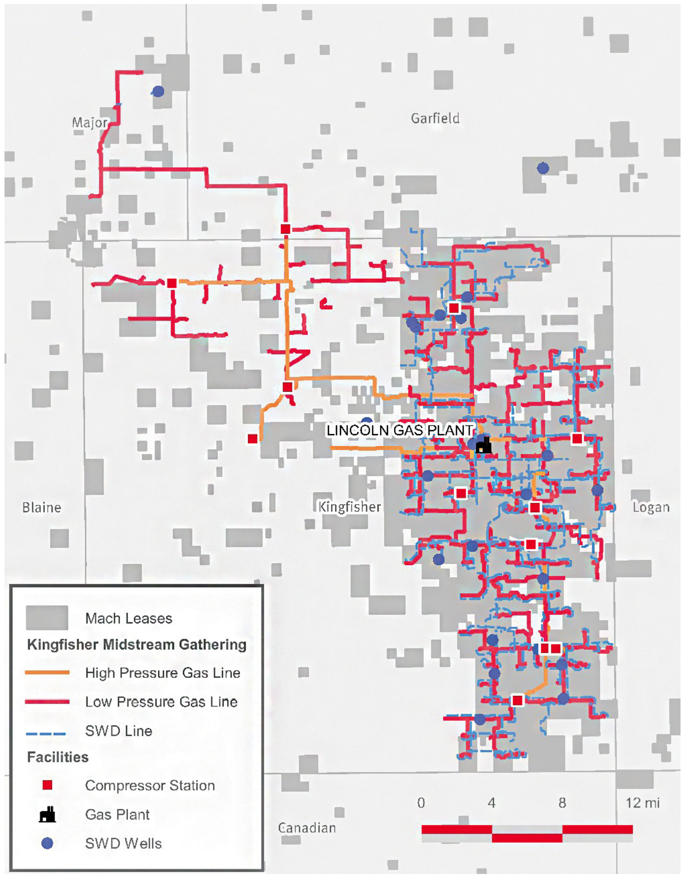
(2) The above table includes 665 drilling locations that have not been evaluated by Cawley, Gillespie & Associates Inc., our independent reserve engineer, that were based solely on the internal evaluations of the Company's management, along with 1,357 of our total drilling locations that have been evaluated by Cawley, Gillespie & Associates Inc., our independent reserve engineer. See "Risk Factors — Risks Related to Our Business — A portion of our estimated drilling locations are based on our management's internal estimates and were not based on evaluations prepared by Cawley, Gillespie & Associates Inc."

We have estimated our drilling locations based on well spacing assumptions for the areas in which we operate and upon the evaluation of our horizontal drilling results and those of other operators in our area, combined with our interpretation of available geologic and engineering data. The drilling locations on which we actually drill will depend on the availability of capital, drilling rigs and labor, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in our ability to add proved reserves to our existing proved reserves. See "Risk Factors — Risks Related to Our Business — Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling."

STACK Area Gas Gathering & Processing ("G&P") and Water Infrastructure

We own a significant complementary portfolio of midstream assets, including gas gathering and processing assets and water infrastructure assets, that supports the development of our properties in Kingfisher County in Oklahoma. For example, the recently constructed Lincoln gas processing plant that we acquired in 2020 has 260 MMcf/d of processing capacity, which is supported by approximately 460 miles of gas gathering lines with approximately 430 receipt point connections, and 27 compressors totaling 35,880 horsepower. Our processing complex has interconnects to both the Panhandle Eastern Pipeline ("PEPL") and ONEOK Gas Transmission ("OGT") system.

Our STACK water infrastructure consists of approximately 300 miles of owned gathering pipeline, and our water disposal assets consist of 20 disposal wells with approximately 377,000 BWPD permitted capacity.



Other Gas Gathering & Processing and Water Infrastructure

In addition to our STACK midstream assets, we own and/or operate other midstream assets, including gas gathering and processing, water infrastructure and compression assets that provide additional margin enhancement for our upstream business.

Within these other midstream assets, our 56% owned and operated Laredo gas gathering system, located in Roger Mills County, Oklahoma and Hemphill County, Texas, has approximately 166 MMcf/d of gathering capacity, which is supported by approximately 160 miles of pipeline. Our 50% owned and contract operated McLean processing facility, located in Gray County, Texas, has approximately 23 MMcf/d of processing capacity and is supported by our wholly owned McLean gathering assets consisting of approximately 510 miles of pipeline spanning seven counties in western Oklahoma and the Texas Panhandle. Our 50% owned and contract operated Madill processing facility, located in Marshall County, Oklahoma, has approximately 40 MMcf/d of processing capacity and is supported by our wholly owned Madill gathering assets consisting of approximately 180 miles of pipeline spanning Marshall and Bryan Counties, Oklahoma. Our wholly owned and operated Elmore City gas gathering and processing facility, located in Garvin County, Oklahoma has approximately 30 MMcf/d of processing capacity supported by approximately 60 miles of pipeline. Our 50% owned Mississippi Lime water infrastructure, located in Alfalfa, Woods and Grant Counties, Oklahoma, aids in the disposal of produced water generated by our operations consisting of approximately 580 miles of pipeline and 35 disposal wells with approximately 300,000 BWPD permitted capacity. Our compression assets consist of a well site compression fleet of approximately 500 units with approximately 89,000 aggregate horsepower.

Development Plan and Capital Budget

Historically, our business plan has focused on acquiring and then exploiting the development and production of our assets. Funding sources for our acquisitions have included proceeds from borrowings under our revolving credit facilities, contributions from our equity partners and cash flow from operating activities. We spent approximately $290.6 million in 2022 on development costs and our budget for 2023 is approximately $ million (of which $ million has been incurred as of June 30, 2023). For purposes of calculating our cash available for distribution, we define development costs as all of our capital expenditures, other than acquisitions. Our development efforts and capital for 2023 is focused on drilling Oswego wells given their high oil reserves and low breakeven costs.

During the year ended December 31, 2022, we spent approximately $270.2 million to drill 87.9 net wells and on related equipment, $9.1 million on remedial workovers and other capital projects, $11.3 million on midstream and other property and equipment capital projects, and $142.9 million on acquisitions.

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.

Our development plan and capital budget are based on management's current expectations and assumptions about future events. While we consider these expectations and assumptions to be reasonable, they are subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated commodity prices, the availability of necessary equipment, infrastructure, drilling rigs, labor and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions and drilling and completion costs.

Our Business Strategies

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

- ***Focus on low decline Legacy Producing Assets with additional meaningful horizontal development inventory.*** Our ability to generate significant cash flow is supported by the predictable low decline production profile of our Legacy Producing Assets, which have an average expected annual decline rate of approximately 15%. Based on our reserve report as of June 30, 2023, 57% of our production is attributable to our low decline Legacy Producing Assets. In addition, we believe we have the ability to maintain or modestly grow our average annual production with the development of our horizontal Focus Drilling Area inventory. We have identified over 2,000 horizontal drilling locations within our 936,000 net acre position, of which at a 10% internal rate of return, over 750 are currently economic at $50 per barrel of oil, over 1,100 at $70 per barrel of oil and over 2,000 at $90 per barrel of oil, each assuming a flat natural gas price per Mcf of 1/20th of the assumed oil price.
- ***Maximize well economics by leveraging midstream infrastructure.*** Our midstream infrastructure assets both reduce our overall upstream costs and generate incremental third-party revenue. In our Oswego formation drilling locations, we estimate that, the oil price necessary to yield a 10% rate of return on invested capital would be approximately $45.47 per barrel of oil equivalent without our midstream assets. We estimate that our complementary midstream assets reduce our average breakeven costs for our Oswego formation drilling locations tied to our owned midstream infrastructure by approximately $4.18 per barrel of oil equivalent to approximately $41.29 per barrel. This reduction consists of the average net cost savings attributable to our working interest resulting from the utilization of our owned midstream infrastructure for gas processing and transportation and water disposal, and the

addition of the incremental third-party midstream revenue attributable to the non-operated portion of the working interest that we do not own. After adding the benefit of our midstream infrastructure, we believe these breakeven costs have comparable economics to the Midland and Delaware Basins.

- ***Maintain low operating cost structure to support meaningful cash available for distribution.*** Our average cash operating costs during the twelve months ended June30, 2023, including the benefit of our midstream infrastructure assets, were $12.51 per barrel of oil equivalent, which is 16% lower on average than other unconventional focused operators, and 58% lower on average than other conventional focused operators during the same period. We believe that our low cost structure will help enable us to make unitholder cash distributions during a negative commodity cycle.

- ***Leverage industry expertise to improve operations and pursue opportunistic acquisitions in Oklahoma.*** Led by industry veteran Tom L. Ward, our senior management team has built lasting relationships with sellers and operators throughout the Anadarko Basin and has developed a track record of acquiring assets at consistently attractive valuations. We believe we can continue to execute opportunistic and accretive transactions that complement our operations in the Anadarko Basin, utilizing our technical expertise to identify acquisition opportunities where our production and cost optimization strategies will yield the greatest returns.

- ***Ensure financial flexibility with conservative leverage and ample liquidity.*** We intend to conduct our operations through cash flow generated from operations with a focus on maintaining a disciplined balance sheet with little to no outstanding debt. Due to our historically 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 strong liquidity profile and remaining substantially debt free. Further, to mitigate the risk associated with volatile commodity prices and to further enhance the stability of our cash flow available for distribution, from time to time we may opportunistically hedge a portion of our production volumes at prices we deem attractive.

Our Strengths

We have a number of differentiated strengths that we believe help us successfully execute our business strategy, including:

- ***Strong production and cash flow across a large acreage position.*** Our average net daily production for the month ended June 30, 2023 was approximately 68 MBoe/d, with approximately 4,500 gross operated wells, and an average working interest of approximately 75%. We own extensive acreage in the Anadarko Basin, with approximately 936,000 net acres, approximately 99% of which is held by production. We believe our large acreage position enables us to optimize our development plan and support significant cash flow generation. For the six months ended June 30, 2023 and year ended December 31, 2022, on a pro forma basis, we generated $199million and $643 million of net income, respectively, $256 million and $714 million of Adjusted EBITDA, respectively, and $46 million and $406 million of cash available for distribution, respectively. See "— Non-GAAP Financial Measures" and "Our Cash Distribution Policy and Restrictions on Distributions — Unaudited Pro Forma Cash Available for Distribution for the Year Ended December 31, 2022 and the Twelve Months Ended June 30, 2023."

- ***Attractive portfolio of large and contiguous core acreage blocks supported by company owned midstream infrastructure.*** Since our founding, we have accumulated an acreage position consisting of approximately 936,000 net acres, of which 99% is held by production, and over 2,000 identified horizontal drilling locations, of which more than 750 are located in the Oswego formation. This large acreage position provides flexibility to accelerate our drilling program or execute opportunistic developments as conditions warrant. In addition, we own substantial gathering and processing assets, which improves our cost structure and enhances the stability of our hydrocarbon flows. We believe our acreage footprint and midstream systems allows us to monetize our production at favorable realized prices and reduces our operating costs while providing us with additional incremental third party revenue streams.

- ***Optimized operations designed to make cash distributions to unitholders.*** Our entrepreneurial culture focuses on operational optimization, cost-minimization, and nimble development to ultimately deliver cash distributions to unitholders across commodity cycles. Our asset profile consists of a large, low cost, and low declining PDP asset, complemented by low-cost horizontal development. Our significant operating experience in the Anadarko Basin and economic advantage conferred by our midstream infrastructure significantly reduces lifting costs relative to other operators. For example, for the twelve months ended June 30, 2023, we achieved a cash operating cost of approximately $12.51 per barrel of oil equivalent, inclusive of the benefit received from our midstream assets. Further, in the early stages of the Oswego horizontal development, a mixture of standard completion fluids and proppant were utilized in the stimulation. Since 2021, we have successfully further lowered our well costs to $3.0 million per well in the Oswego by using drilling efficiencies and utilizing acid in lieu of proppant within the stimulation. Due to our low completion costs, low operating costs, and our midstream advantage, we believe the average breakeven price for our Oswego drilling locations is $41.29 price per barrel of oil.

- ***Experienced management team with established record of value creation.*** We believe our management team's experience in the Anadarko Basin offers a distinguishing advantage. The members of management have an average of 32 years of experience in the oil and gas industry and have successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets. Additionally, our Chief Executive Officer, Tom L. Ward, has over a 40-year history in the oil and gas industry. Further, through our team's history of operating in Oklahoma, we have built lasting relationships with sellers and developed a track record of successfully acquiring and integrating assets at attractive valuations. Since our founding, we have successfully executed 15 acquisitions for an aggregate purchase price of approximately $950 million, increasing our net acreage to 936,000, and our average net daily production for the month ended June 30, 2023 was approximately 68 MBoe/d. Additionally, during the same period, we distributed approximately $616 million in cash to our members. We believe our management team has the experience, expertise and commitment to create significant value in the form of cash distributions to our unitholders.

- ***Conservatively capitalized balance sheet and strong liquidity profile.*** Since our founding, we have practiced financial conservatism and maintained a strong balance sheet with low leverage. Due to our significant existing low-decline production base, our business generates significant operating cash flow. Upon consummation of this offering, we expect to have little to no debt and substantial liquidity, which will provide us further financial flexibility to fund our capital expenditures and execute our strategic plan.

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 prospectus 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 payment of expenses, funding of development costs and establishment of cash reserves.

- 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 will not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Risks Related to Our Business

- Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, results of operations, liquidity, ability to meet our financial commitments, ability to make our planned capital expenditures and our cash available for distribution.

- Currently, our producing properties are concentrated in the Anadarko Basin, making us vulnerable to risks associated with operating in a limited number of geographic areas.

- Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.
- Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.
- The marketability of our production is dependent upon gathering, treating, processing and transportation facilities, some of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues could decrease.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- We depend on Mach Resources LLC ("Mach Resources") to provide us services necessary to operate our business. If Mach Resources were unable or unwilling to provide these services, it would result in a disruption in our business that could have an adverse effect on our financial position, financial results and cash flow.
- The unavailability or high cost of drilling rigs, frac crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.
- Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.
- Events outside of our control, including widespread public health crises, epidemics and outbreaks of infectious diseases such as COVID-19, or the threat thereof, and any related threats of recession and other economic repercussions 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.
- Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conversation measures, technological advances and negative shift in market perception towards the oil and natural gas industry, which could result in increased operating expenses and capital costs, financial risks and reduction in demand for oil and natural gas.
- Increased scrutiny of environmental, social, and governance ("ESG") matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

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 does not restrict the Sponsor (as defined below) 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 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 unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, 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.
- We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for U.S. 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 U.S. 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.

Reorganization Transactions, Partnership Structure and New Credit Facility

Each of the following transactions (collectively, the "Reorganization Transactions") have occurred or will occur immediately prior to the closing of this offering:

- BCE through its affiliate holding companies will contribute 100% of its membership interests in BCE-Mach, BCE-Mach II, and BCE-Mach III (collectively, the "Mach Companies") not already owned by BCE-Mach Aggregator LLC ("BCE-Mach Aggregator") to BCE-Mach Aggregator in exchange for additional membership interests in BCE-Mach Aggregator;
- Each of BCE-Mach Aggregator, the Management Members and Mach Resources will contribute 100% of their respective membership interests in the Mach Companies to the Company in exchange for a pro rata allocation of 100% of the limited partner interests in the Company;
- The Company will contribute 100% of its membership interests in the Mach Companies to Mach Natural Resources Intermediate LLC ("Intermediate") in exchange for 100% of the membership interests in Intermediate; and
- Intermediate will contribute 100% of its membership interests in the Mach Companies to Mach Natural Resources Holdco LLC ("Holdco") in exchange for 100% of the membership interests in Holdco.

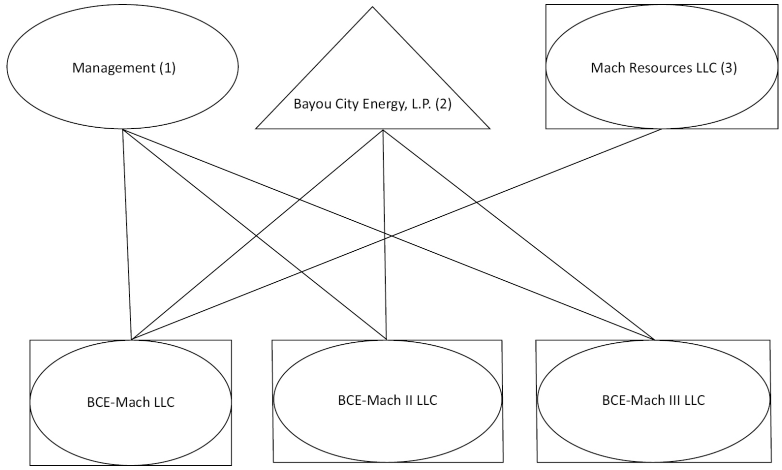
Except where specified otherwise, the disclosure in this prospectus gives effect to the Reorganization Transactions.

New Credit Facility

Contemporaneously with the closing of this offering, we expect to enter into a new credit facility led by (the "New Credit Facility"). The New Credit Facility is expected to have a total facility size of $ million, an initial borrowing base of $ million and available capacity of $ million. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt agreements — New Credit Facility."

Ownership and Organizational Structure of Mach Natural Resources

The diagram below depicts our organization and ownership before giving effect to the offering and the Reorganization Transactions.

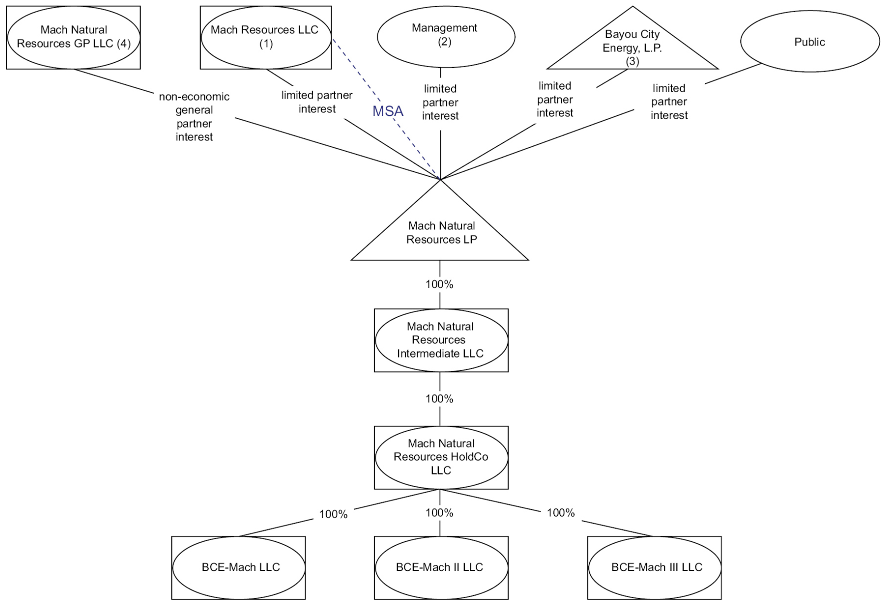


(1) Collectively refers to our current officers and employees who own direct and indirect equity interests in the Mach Companies.

(2) Bayou City Energy, L.P. owns its interests in BCE-Mach LLC, BCE-Mach II LLC and BCE-Mach III LLC through certain wholly-owned holding companies.

(3) Mach Resources is owned 50.5% by Tom L. Ward through the Tom L Ward 1992 Revocable Trust and 49.5% by WCT Resources LLC which is owned by certain trusts owned by certain of Tom L. Ward's family members. Our general partner will contract with Mach Resources for our employees and other services. See "Certain Relationships and Related Party Transactions."

The diagram below depicts our organization and ownership after giving effect to the offering and the Reorganization Transactions and assumes that the underwriters do not exercise their option to purchase additional common units.



(1) Mach Resources is owned 50.5% by Tom L. Ward through the Tom L Ward 1992 Revocable Trust and 49.5% by WCT Resources LLC which is owned by certain trusts owned by certain of Tom L. Ward's family members. Our general partner will contract with Mach Resources for our employees and other services. See "Certain Relationships and Related Party Transactions."
(2) Collectively refers to our current officers and employees who own direct and indirect equity interests in the Mach Companies.
(3) Bayou City Energy, L.P. will own its interests in Mach Natural Resources LP through certain wholly-owned holding companies.
(4) BCE-Mach Aggregator LLC and certain members of management wholly own Mach Natural Resources GP LLC, our general partner.

Management of Mach Natural Resources

We are managed and operated by the board of directors (the "Board") and executive officers of our general partner, Mach Natural Resources GP LLC. Our unitholders will not be entitled to elect our general partner or its directors or otherwise participate in our management or operations. For information about the executive officers and directors of our general partner, please read "Management."

The members of our general partner are BCE-Mach Aggregator, all of the membership interests of which are owned by Bayou City Energy, L.P. and its affiliates, which we refer to collectively as the Sponsor, and certain members of management. The Sponsor and management will own our general partner in the same proportion to each other as their respective limited partner interest ownership in us. As a result, the Sponsor and management will control our general partner and will be entitled to appoint its entire board of directors.

Our operations are conducted through, and our assets are currently owned by, various subsidiaries. Although all of the employees that conduct our business are either employed by Mach Resources or its subsidiaries, we sometimes refer to these individuals in this prospectus as our employees.

Our Sponsor

Our sponsor, Bayou City Energy, L.P. ("BCE" or "Sponsor"), was founded in 2015 by Will McMullen and is a leading upstream-focused private equity firm with $2.2 billion in assets under management. BCE targets control-oriented investment in free-cash-flow focused assets in partnership with best-in-class management teams. BCE has invested approximately $1.0 billion in the Mid-Continent region, and has an investment team with diverse experience across the sector. We believe our relationship with our sponsor gives us access to a highly accomplished and cohesive and aligned investment partner.

Implications of Being an Emerging Growth Company

We are an "emerging growth company" as defined in the Jumpstart Our Business Startups Act (the "JOBS Act"). For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies under the JOBS Act, we are not required to:

- 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;
- provide more than two years of audited financial statements and related management's discussion and analysis of financial condition and results of operations nor more than two years of selected financial data in a registration statement on Form S-1;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board (the "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; or
- provide certain disclosure regarding executive compensation required of larger public companies required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act").

We will cease to be an emerging growth company upon the earliest of:

- the last day of the fiscal year in which we have $1.235 billion or more in annual revenues (as such amount may be adjusted by the SEC for inflation);
- the date on which we become a "large accelerated filer" (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30 of such year);
- the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended (the "Securities Act"), for complying with new or revised accounting standards. We have elected to avail ourselves of the provision of the JOBS Act that permits emerging growth companies to take advantage of an extended transition period to comply with new or revised accounting standards applicable to public companies. As a result, we will not be subject to new or revised accounting standards at the same time as other public companies that are not emerging growth companies. We intend to take advantage of the other exemptions discussed above, both in this prospectus and in future filings with the U.S. Securities and Exchange Commission (the "SEC"). Accordingly, the information contained herein and that we provide to our unitholders from time to time may be different than the information you receive from other public companies. For additional information, see the section titled "Risk Factors — Risks Inherent in an Investment in Us — 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. 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."

Principal Executive Offices and Internet Address

Our principal executive offices are located at 14201 Wireless Way, Suite 300, Oklahoma City, Oklahoma 73134 and our telephone number at that address is (405) 252-8100. Our website address is *www.machresources.com*. We expect to make our periodic reports and other information filed with or furnished to the SEC available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on, or otherwise accessible through, our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

Summary of Conflicts of Interest and Duties

Under our partnership agreement, our general partner has a duty to manage us in a manner it believes is not adverse to our best interests. However, because our general partner is owned by BCE-Mach Aggregator and certain members of our management, the officers and directors of our general partner also have a duty to manage the business of our general partner at the direction of BCE-Mach Aggregator and certain members of our management. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates, including the Sponsor and certain members of our management in their capacities as members of our general partner, on the other hand; provided, however, that upon our adoption of our code of business conduct, we would expect that any such member of our management, so long as they are an executive officer, will be required to avoid personal conflicts of interest and not compete against us, in each case unless approved by the Board. For example, our general partner is entitled to make determinations that affect our ability to generate the cash flow necessary to make cash distributions to our unitholders, including determinations related to:

- purchases and sales of oil and natural gas properties and other acquisitions and dispositions, including whether to pursue acquisitions that may also be suitable for the Sponsor or any affiliate of the Sponsor;
- the manner in which our business is operated;
- the level of our borrowings;
- the amount, nature and timing of our capital expenditures; and
- the amount of cash reserves necessary or appropriate to satisfy our general, administrative and other expenses and debt service requirements and to otherwise provide for the proper conduct of our business.

For a more detailed description of the conflicts of interest and duties of our general partner, please read "Risk Factors — Risks Inherent in an Investment in Us" and "Conflicts of Interest and Duties."

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 any common units held by our general partner and its affiliates). Upon consummation of this offering, our general partner will continue to be controlled by the Sponsor and certain members of management, who will own and control the voting of an aggregate of approximately % and %, respectively, of our outstanding common units. Assuming that we do not issue any additional common units and the Sponsor and these members of management do not transfer their respective common units, the Sponsor and these members of management will have the ability to control any amendment to our partnership agreement, including our policy to distribute all of our available cash to our unitholders. Please see "Risk Factors — Risks Inherent in an Investment in Us" and "The Partnership Agreement — Amendment of the Partnership Agreement."

Delaware law provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties owed by the general partner to limited partners and the partnership. Our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of our general partner and contractual methods of resolving conflicts of interest. The effect of these provisions is to restrict the duties owed and remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of its fiduciary duties. Our partnership agreement also provides that affiliates of our general partner, including the Sponsor and its affiliates, are not restricted from competing with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and pursuant to the terms of our partnership agreement, each holder of common units consents to various actions and potential conflicts of interest contemplated in our partnership agreement that might otherwise be considered a breach of fiduciary or other duties under Delaware law. Please read "Conflicts of Interest and Duties — Duties of Our General Partner" for a description of the duties imposed on our general partner by Delaware law, the replacement of those duties with contractual standards under our partnership agreement and certain legal rights and remedies available to holders of our common units.

In connection with this offering, the Company will enter into a management services agreement ("MSA") with Mach Resources. Under the MSA, Mach Resources will manage and perform all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company will reimburse Mach Resources for certain costs and expenses related to its performance under the MSA. For a description of our other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions."

The Offering

Common units offered by us	common units representing limited partner interests (common units if the underwriters exercise in full their option to purchase additional common units).
Units outstanding after this offering	common units representing limited partner interests in us (common units if the underwriters exercise their option in full to purchase additional common units).
Use of proceeds	We intend to use the expected net proceeds of approximately $ million from this offering ($ million if the underwriters exercise their option to purchase additional units in full), based upon the assumed initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover of this prospectus), after deducting underwriting discounts and estimated expenses, to repay the Existing Credit Facilities with the remainder used for general partnership purposes. See "Use of Proceeds."
Cash distributions	Within 60 days after the end of each quarter (other than the fourth quarter) and within 90 days after the end of the fourth quarter, beginning with the quarter ending , 2023, we expect to pay distributions of our available cash to unitholders of record on the applicable record date. The board of directors of our general partner will adopt a policy pursuant to which distributions for each quarter will be paid to the extent we have sufficient cash after establishment of cash reserves and payment of expenses, development costs and fees, including payments to our general partner and its affiliates. Our ability to pay such cash distributions is subject to various restrictions and other factors described in more detail under the caption "Our Cash Distribution Policy and Restrictions on Distributions." We will prorate the amount of our distribution payable for the period from the closing of this offering through , 2023, based on the actual length of that period. Our partnership agreement generally provides that we will distribute all available cash each quarter to the holders of common units, pro rata. Pro forma cash available for distribution generated during the year ended December 31, 2022 and twelve months ended June 30, 2023 was approximately $ million and $ million, respectively. As a result, for the year ended December 31, 2022 and twelve months ended June 30, 2023, we would have generated available cash sufficient to pay a cash distribution of $ and $ per unit per quarter, respectively ($ and $ on an annualized basis, respectively). For a calculation of our ability to pay distributions to our unitholders based on our pro forma results for the year ended December 31, 2022 and twelve months ended June 30, 2023, please read "Our Cash Distribution Policy and Restrictions on Distributions — Unaudited Pro Forma Cash Available for the Year Ended December 31, 2022 and Twelve Months Ended June 30, 2023." We believe, based on our financial forecast and the related assumptions included under "Our Cash Distribution Policy and Restrictions on Distributions — Estimated Cash Available for Distribution for the Twelve Months Ending June 30, 2024," that we will have sufficient cash available for distribution to make cash distributions of $ per unit on all common units (on an annualized basis) for the four quarters ending June 30, 2024. We will not have a minimum quarterly distribution nor is there any guarantee that we will make any particular amount of distributions or any distributions to our unitholders in any quarter. Please read "Our Cash Distribution Policy and Restrictions on Distributions."

Issuance of additional units	We can issue an unlimited number of additional units, including units that are senior to the common units in right of distributions, liquidation and voting, on terms and conditions determined by our general partner, without the approval of our unitholders. Please read “Units Eligible for Future Sale” and “The Partnership Agreement — Issuance of Additional Partnership Interests.”
Limited voting rights	Our general partner will manage us and operate our business. Unlike stockholders of a corporation, our unitholders will have only limited voting rights on matters affecting our business. Our unitholders will have no right to elect our general partner or its board of directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least 66⅔% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Upon consummation of this offering, the affiliates of the general partner (including the Sponsor and members of management) will own an aggregate of approximately % of our common units and, therefore, will be able to prevent the removal of our general partner. Please read “The Partnership Agreement — Limited Voting Rights.”
Limited call right	If at any time our general partner and its affiliates own more than % of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a purchase price not less than the then-current market price of the common units, as calculated pursuant to the terms of our partnership agreement. Upon consummation of this offering, affiliates of our general partner (including the Sponsor and members of management) will own an aggregate of approximately % of our common units. Please read “The Partnership Agreement — Limited Call Right.”
Election to be treated as a corporation	If at any time our general partner determines that (i) we should no longer be characterized as a partnership but instead as an entity taxed as a corporation for U.S. federal income tax purposes or (ii) common units held by some or all unitholders should be converted into or exchanged for interests in a newly formed entity taxed as a corporation for U.S. federal income tax purposes whose sole asset is interests in us (“parent corporation”), then our general partner may, without unitholder approval, reorganize us and cause us to be treated as an entity taxable as a corporation for U.S. federal income tax purposes or cause common units held by some or all unitholders to be converted into or exchanged for interests in the parent corporation. 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. Please read “Risk Factors — Risks Inherent in an Investment in Us — 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” and “The Partnership Agreement — Election to be treated as a Corporation.”

Eligible Holders and redemption	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. We have the right (which we may assign to any of our affiliates), but not the obligation, to redeem all of the common units of any holder that is not an eligible holder pursuant to our partnership agreement or that has failed to certify or has falsely certified that such holder is an eligible holder. The purchase price for such redemption would be equal to the then-current market price of the common units. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read "Description of the Common Units — Transfer Agent and Registrar — Transfer of Common Units" and "The Partnership Agreement — Non-Citizen Unitholders; Redemption."
Estimated ratio of taxable income to distributions	We estimate that if our unitholders own the common units purchased in this offering through the record date for distributions for the period ending December 31, 2025, such unitholders will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than % of the cash distributed to such unitholders with respect to that period. Please read "Material U.S. Federal Income Tax Consequences — Tax Consequences of Unit Ownership — Ratio of Taxable Income to Distributions" for the basis of this estimate.
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read "Material U.S. Federal Income Tax Consequences."
Listing and trading symbol	We intend to apply to list our common units on the NYSE under the symbol "MNRE."

Summary Historical and Pro Forma Financial and Operating Data

Unless otherwise indicated, the historical financial information presented in this prospectus is that of our predecessor. The historical financial information of BCE-Mach LLC and BCE-Mach II LLC is also included herein as indicated.

The summary historical financial data set forth below as of and for each of the years ended December 31, 2022 and 2021 have been derived from our audited consolidated financial statements included elsewhere in this prospectus. The summary historical financial data set forth below as of June 30, 2023 and for the six months ended June 30, 2023 and 2022 have been derived from our unaudited financial statements and related notes included elsewhere in this prospectus.

The summary unaudited pro forma financial data as of June30, 2023 and for the six months ended June 30, 2023 and year ended December31, 2022 are derived from the unaudited pro forma condensed combined financial statements of Mach Natural Resources included elsewhere in this prospectus, which reflect the historical results of our predecessor, BCE-Mach LLC and BCE-Mach II LLC on a pro forma basis to give effect to the following transactions, which are described in further detail below, as if they had occurred on June 30, 2023, for pro forma balance sheet purposes, and on January1, 2022, for pro forma statements of operations purposes:

- the Reorganization Transactions as described in "— Reorganization Transactions, Partnership Structure and New Credit Facility" elsewhere in this prospectus summary; and
- the issuance and sale by us to the public of common units in this offering and the application of the net proceeds as described in "Use of Proceeds."

  Contemporaneously with the closing of this offering, we expect to use the proceeds of this offering to pay down the balances of the Existing Credit Facilities. We also expect to enter into a New Credit Facility contemporaneously with the closing of this offering. The New Credit Facility (under which no amounts will be outstanding at the closing of this offering) is expected to have a total facility size of $ million, an initial borrowing base of $ million and available capacity of $ million.

We have not given pro forma effect to the incremental general and administrative expenses that we expect to incur annually as a result of being a publicly traded partnership.

The unaudited pro forma historical financial data are presented for illustrative purposes only and are not necessarily indicative of the financial position that would have existed or the financial results that would have occurred if this offering and the Reorganization Transactions had occurred on the dates indicated, nor are they necessarily indicative of the financial position or results of our operations in the future. The pro forma adjustments, as described in the notes to the unaudited pro forma condensed combined financial statements, are preliminary and based upon currently available information and certain assumptions that our management believes are reasonable. The summary historical financial data are qualified in their entirety by, and should be read in conjunction with, the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section included in this prospectus and the consolidated financial statements and related notes and other financial information included in this prospectus. Among other things, those historical financial statements and unaudited pro forma condensed combined financial statements include more detailed information regarding the basis of presentation for the following information. Historical results are not necessarily indicative of results that may be expected for any future period.

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The following table presents non-GAAP financial measures, Adjusted EBITDA and cash available for distribution, which we use in evaluating the financial performance of our business. These measures are not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain these measures below and reconcile them to the most directly comparable financial measures calculated and presented in accordance with GAAP.

	Predecessor Historical				Mach Natural Resources Pro Forma	
	Six Months Ended June 30,		Year Ended December 31,		Six Months Ended June 30,	Year Ended December 31,
(in thousands, except per unit amounts)	2023	2022	2022	2021	2023	2022
Statement of Operations Data:						
Operating Revenues:						
Oil, natural gas and NGL sales	$ 312,613	$ 408,442	$ 860,388	$ 397,500	$ 399,686	$ 1,165,420
Midstream revenue	13,318	19,883	44,373	31,883	13,531	44,832
Gain (loss) on oil and natural gas derivatives, net	15,742	(72,857)	(67,453)	(67,549)	22,618	(113,322)
Product sales	17,421	47,960	100,106	30,663	17,421	100,106
Total operating revenue	359,094	403,428	937,414	392,497	453,256	1,197,036
Operating Expenses:						
Gathering and processing expense	17,510	20,812	47,484	27,987	33,430	87,887
Lease operating expense	60,615	39,592	95,941	45,391	87,439	145,267
Midstream operating expense	5,538	6,976	15,157	12,248	5,761	15,618
Cost of product sales	15,575	44,958	94,580	28,687	15,575	94,580
Production taxes	15,526	22,675	47,825	21,165	20,003	65,194
Depreciation, depletion, amortization and accretion expense – oil and natural gas	58,095	29,374	84,070	37,537	72,117	119,359
Depreciation and amortization expense – other	2,793	2,008	4,519	3,148	3,171	5,445
General and administrative expense	9,905	13,648	25,454	60,927	11,750	19,278
Total operating expenses	185,557	180,043	415,030	237,090	249,246	552,628
Income from operations	173,537	223,385	522,384	155,407	204,010	644,408
Other income (expenses):						
Interest expense	(3,789)	(1,876)	(4,852)	(1,656)	—	—
Other income (expense), net	(245)	1,121	(691)	1,023	(4,966)	(1,083)
Loss on contingent consideration	—	—	—	(16,400)	—	—
Total other income (expenses)	(4,034)	(755)	(5,543)	(17,033)	(4,966)	(1,083)
Net income	$ 169,503	$ 222,630	$ 516,841	$ 138,374	$ 199,044	$ 643,325
Net income per limited partner unit:						
Basic	$	$	$	$		$
Diluted	$	$	$	$		$
Weighted average number of limited partner units outstanding:						
Basic						
Diluted						
Other Financial Data:						
Adjusted EBITDA[1]	$ 227,261	$ 276,408	$ 594,429	$ 248,617	$ 255,709	$ 714,305
Cash available for distribution[2]	$ 35,308	$ 159,701	$ 300,944	$ 184,445	$ 45,632	$ 405,888
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 275,145	$ 227,936	$ 553,542	$ 198,462		
Investing activities	$ (187,812)	$ (212,951)	$ (372,660)	$ (194,743)		
Financing activities	$ (67,904)	$ (27,236)	$ (210,737)	$ (4,584)		

	Predecessor Historical				Mach Natural Resources Pro Forma	
	Six Months Ended June 30,		Year Ended December 31,		Six Months Ended June 30,	Year Ended December 31,
(in thousands, except per unit amounts)	2023	2022	2022	2021	2023	2022
Balance Sheet Data (at period end):						
Cash and cash equivalents	$ 48,846		$ 29,417	$ 59,272	$ 109,608	
Oil and natural gas properties, net	$ 744,071		$ 610,420	$ 277,922	$ 1,085,208	
Total assets	$ 979,312		$ 887,441	$ 525,379	$ 1,458,331	
Total long-term liabilities	$ 150,354		$ 141,570	$ 117,241	$ 115,143	
Members'/Partners' capital	$ 689,527		$ 593,230	$ 278,699	$ 1,139,866	

(1) Adjusted EBITDA is a non-GAAP financial measure, please see "— Non-GAAP Financial Measures" below.
(2) Cash available for distribution is a non-GAAP financial measure, please see "— Non-GAAP Financial Measures" below.

Non-GAAP Financial Measures

Adjusted EBITDA

We include in this prospectus the non-GAAP financial measure Adjusted EBITDA and provide our calculation of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income, our most directly comparable financial measures calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income before (1) interest expense, (2) depreciation, depletion and amortization, (3) unrealized (gain) loss on derivative settlements, (4) equity-based compensation expense, (5) loss on contingent consideration and (6) (gain) loss on sale of assets.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to more effectively evaluate our operating performance and our results of operation from period to period and against our peers without regard to financing methods, capital structure or historical cost basis. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA is not a measurement of our financial performance under GAAP and should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as indicators of our operating performance. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax burden, as well as the historic costs of depreciable assets, none of which are reflected in Adjusted EBITDA. Our presentation of Adjusted EBITDA should not be construed as an inference that our results will be unaffected by unusual items. Our computations of Adjusted EBITDA may not be identical to other similarly titled measures of other companies.

Cash Available for Distribution

Cash available for distribution is not a measure of net income or net cash flow provided by or used in operating activities as determined by GAAP. Cash available for distribution is a supplemental non-GAAP financial measure used by our management and by external users of our financial statements, such as investors, lenders and others (including industry analysts and rating agencies who will be using such measure), 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 net income less (1) interest expense, (2) depreciation, depletion and amortization, (3) unrealized (gain) loss on derivative settlements, (4) equity-based compensation expense, (5) loss on contingent consideration, (6) (gain) loss on sale of assets, (7) settlement of asset retirement obligations, (8) net cash interest expense, (9) development costs, (10) settlement of contingent consideration and (11) change in accrued realized derivative settlements. Development costs include all of our capital expenditures, other than acquisitions. Cash available for distribution will not reflect changes in working capital balances. Cash available for distribution is not a measurement of our financial performance or liquidity under GAAP and should not be considered as an alternative to, or more meaningful than, net income or net cash provided by or used in operating activities as determined in accordance with GAAP or as indicators of our financial performance and liquidity. The GAAP measures most directly comparable to cash available for distribution are net income and net cash provided by operating activities. Cash available for distribution should not be considered as an alternative to, or more meaningful than, net income or net cash provided by operating activities.

Reconciliations of GAAP Financial Measures to Adjusted EBITDA and Cash Available for Distribution

The following table presents our reconciliation of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measures Adjusted EBITDA and cash available for distribution, as applicable, for each of the periods indicated.

	Predecessor Historical				Mach Natural Resources Pro Forma	
	Six Months Ended June 30,		Year Ended December 31,		Six Months Ended June 30,	Year Ended December 31,
(in thousands) (unaudited)	2023	2022	2022	2021	2023	2022
Net Income Reconciliation to Adjusted EBITDA:						
Net income	$ 169,503	$ 222,630	$ 516,841	$ 138,374	$ 199,044	$ 643,325
Interest expense	3,789	1,876	4,852	1,656	—	—
Depreciation, depletion and amortization	60,888	31,382	88,589	40,685	75,288	124,804
Unrealized (gain) loss on derivative settlements	(8,212)	16,735	(23,335)	6,284	(18,622)	(53,730)
Equity-based compensation expense	1,294	3,763	7,527	45,303	—	—
Loss on contingent consideration	—	—	—	16,400	—	—
(Gain) loss on sale of assets	(1)	22	(45)	(85)	(1)	(94)
Adjusted EBITDA	227,261	276,408	594,429	248,617	255,709	714,305
Net Income Reconciliation to Cash Available for Distribution:						
Net income	$ 169,503	$ 222,630	$ 516,841	$ 138,374	$ 199,044	$ 643,325
Interest expense	3,789	1,876	4,852	1,656	—	—
Depreciation, depletion and amortization	60,888	31,382	88,589	40,685	75,288	124,804
Unrealized (gain) loss on derivative settlements	(8,212)	16,735	(23,335)	6,284	(18,622)	(53,730)
Equity-based compensation expense	1,294	3,763	7,527	45,303	—	—
Loss on contingent consideration	—	—	—	16,400	—	—
(Gain) loss on sale of assets	(1)	22	(45)	(85)	(1)	(94)
Settlement of asset retirement obligations	(79)	(49)	(49)	(35)	(133)	(206)
Cash interest expense, net	(3,587)	(1,690)	(4,477)	(1,344)	(6,992)	—
Development costs[1]	(188,002)	(109,224)	(271,999)	(55,124)	(200,371)	(290,636)
Settlement of contingent consideration	—	(8,111)	(13,547)	(9,553)	—	(13,547)
Change in accrued realized derivative settlements	(285)	2,367	(3,413)	1,884	(2,581)	(4,028)
Cash Available for Distribution	$ 35,308	$ 159,701	$ 300,944	$ 184,445	$ 45,632	$ 405,888
Net Cash Provided by Operating Activities Reconciliation to Cash Available for Distribution:						
Net cash provided by operating activities	$ 275,145	$ 227,936	$ 553,542	$ 198,462		
Changes in operating assets and liabilities	(51,835)	40,989	19,401	41,107		
Development costs[1]	(188,002)	(109,224)	(271,999)	(55,124)		
Cash Available for Distribution	$ 35,308	$ 159,701	$ 300,944	$ 184,445		

(1) Development costs includes all of our capital expenditures, other than acquisitions.

Reconciliation of PV-10 to Standardized Measure

Certain of our oil and natural gas reserve disclosures included in this prospectus are presented on a PV-10 basis. PV-10 is a non-GAAP financial measure and represents the estimated present value of the future cash flows less future development and production costs from our proved and probable reserves before income taxes discounted using a 10% discount rate. PV-10 of proved reserves generally differs from the standardized measure of discounted future net cash flows from production of proved oil and natural gas reserves (the "Standardized Measure"), the most directly comparable GAAP financial measure, because it does not include the effects of future income taxes, as is required under GAAP in computing the Standardized Measure. However, our PV-10 for proved and probable reserves using SEC pricing and the Standardized Measure of proved reserves are equivalent because we were not subject to entity level taxation. Accordingly, no provision for federal or state income taxes has been provided in the Standardized Measure because taxable income is passed through to our unitholders.

We believe that the presentation of a pre-tax PV-10 value provides relevant and useful information because it is widely used by investors and analysts as a basis for comparing the relative size and value of our proved and probable reserves to other oil and natural gas companies. Because many factors that are unique to each individual company may impact the amount and timing of future income taxes, the use of PV-10 value provides greater comparability when evaluating oil and natural gas companies. The PV-10 value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of proved oil and gas reserves. However, the definition of PV-10 value as defined above may differ significantly from the definitions used by other companies to compute similar measures. As a result, the PV-10 value as defined may not be comparable to similar measures provided by other companies.

Investors should be cautioned that neither PV-10 nor Standardized Measure of proved reserves represents an estimate of the fair market value of our proved and probable reserves. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

Summary of Reserve, Production and Operating Data

The following tables summarize our estimated proved and probable oil, natural gas and NGL reserves as of June 30, 2023 and our estimated proved oil, natural gas and NGL reserves as of December 31, 2022 and our production and historical operating data for the six months ended June 30, 2023 and year ended December 31, 2022 on a pro forma combined basis. The information included in these tables consolidates information about the Mach Companies and is based on reserve reports prepared by our independent consulting petroleum engineers, Cawley, Gillespie & Associates, Inc. For more information regarding our reserve volumes and values, see "Business and Properties — Operating Data" and our summary reserve report filed as an exhibit to the registration statement of which this prospectus forms a part. Historical reserve volumes and values are not necessarily indicative of results that may be expected for any future period.

Summary of Reserves

Our historical SEC reserves, PV-10 and Standardized Measure of proved reserves were calculated using oil and gas price parameters established by current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions ("SEC Pricing"). These prices were adjusted for differentials on a per-property basis, which may include local basis differential, fuel costs and shrinkage. All prices are held constant throughout the lives of the properties.

	Mach Natural Resources Pro Forma	
	As of June 30, 2023 SEC Pricing(1)	As of December 31, 2022 SEC Pricing(1)
Proved Developed:		
Oil (MBbl)	40,876	43,306
Natural gas (MMcf)	782,727	838,298
Natural gas liquid (MBbl)	50,190	59,761
Oil equivalent (MBoe)	221,520	242,782
PV-10 (in millions)(2)	$ 2,131	$ 3,334
Proved Undeveloped:		
Oil (MBbl)	12,153	23,438
Natural gas (MMcf)	28,781	144,380
Natural gas liquid (MBbl)	721	9,978
Oil equivalent (MBoe)	17,671	57,480
PV-10 (in millions)(2)	$ 304	$ 724
Total Proved:		
Oil (MBbl)	53,029	66,744
Natural gas (MMcf)	811,507	982,678
Natural gas liquid (MBbl)	50,911	69,739
Oil equivalent (MBoe)	239,191	300,262
Standardized Measure (in millions)(2)	$ 2,435	$ 4,058
PV-10 (in millions)(2)	$ 2,435	$ 4,058
Probable:(3)		
Oil (MBbl)	72,868	—
Natural gas (MMcf)	373,477	—
Natural gas liquid (MBbl)	19,576	—
Oil equivalent (MBoe)	154,690	—
PV-10 (in millions)(2)	$ 1,039	$ —

(1) Our estimated net proved and probable 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 $6.358 per Mcf for natural gas at January 1, 2023 and $82.82 per barrel for oil and $4.763 per MMBtu for natural gas at June 30, 2023. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, fuel costs and shrinkage.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved and probable oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. For more information on how we calculate PV-10 and a reconciliation of proved reserves PV-10 to its nearest GAAP measure, see "— Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure." With respect to PV-10 calculated as of an interim date, it is not practicable to calculate the taxes for the related interim period because GAAP does not provide for disclosure of Standardized Measure on an interim basis.

(3) Estimates of probable reserves, and the future cash flows related to such estimates, are inherently imprecise and are more uncertain than estimates of proved reserves and the future cash flows related to such estimates but have not been adjusted for risk due to such uncertainty. Therefore, estimates of probable reserves and the future cash flows related to such estimates may not be comparable to estimates of proved reserves and the future cash flows related to such estimates and should not be summed arithmetically with estimates of proved reserves and the future cash flows related to such estimates. For more information regarding the presentation of probable reserves, see "Business and Properties — Our Operations — Preparation of Reserve Estimates."

Select Production and Operating Statistics

The following table summarizes the Mach Companies' oil, natural gas and NGL production and historical operating data for the periods presented on a combined unaudited pro forma basis.

The unaudited pro forma combined net production volumes and realized prices for the six months ended June 30, 2023 and year ended December 31, 2022 treat the Reorganization Transactions as if they had occurred on January 1, 2022.

	Mach Natural Resources Pro Forma	
	Six Months Ended June 30, 2023	**Year Ended December 31, 2022**
Net Production Volumes:		
Oil (MBbl)	3,370	5,982
Natural Gas (MMcf)	38,675	70,947
NGLs (MBbl)	2,045	4,246
Total (MBoe)	11,861	22,053
Average daily production (MBoe/d)	65.53	60.42
Average Wellhead Realized Prices (before giving effect to realized derivatives):		
Oil (/Bbl)	$ 74.93	$ 93.60
Natural Gas (/Mcf)	$ 2.50	$ 6.21
NGLs (/Bbl)	$ 24.72	$ 38.85
Average Wellhead Realized Prices (after giving effect to realized derivatives):		
Oil (/Bbl)	$ 72.19	$ 78.94
Natural Gas (/Mcf)	$ 2.84	$ 5.09
NGLs (/Bbl)	$ 24.72	$ 38.85
Operating costs and expenses (per Boe):		
Gathering and processing expense	$ 2.82	$ 3.99
Lease operating expense	$ 7.37	$ 6.59
Production taxes expense (% of oil, natural gas and NGL sales)	5.0%	5.6%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 6.08	$ 5.41
Depreciation and amortization expense – other	$ 0.27	$ 0.25
General and administrative expense	$ 0.99	$ 0.87

RISK FACTORS

Investing in our common units involves a high degree of risk. You should carefully consider the risks described below with all of the other information included in this prospectus before deciding to invest in our common units. 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 payment of expenses, funding of development costs and establishment of cash reserves.

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, cash interest, development costs 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;
- the restrictive covenants in our New Credit Facility and other agreements governing indebtedness that limit our ability to pay dividends or distributions in respect of our equity; 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 will not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Investors who are looking for an investment that will pay regular and predictable quarterly distributions should not invest in our common units. Our future business performance may be volatile, and our cash flows may be unstable. We will 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 and Restrictions on Distributions.”

The assumptions underlying the forecast of cash available for distribution we include in "Our Cash Distribution Policy and Restrictions on Distributions" may prove inaccurate and are subject to significant risks and uncertainties that could cause actual results to differ materially from our forecasted results.

Our management's forecast of cash available for distribution set forth in "Our Cash Distribution Policy and Restrictions on Distributions" includes our forecasted results of operations, Adjusted EBITDA and cash available for distribution for the twelve months ending June 30, 2024. The assumptions underlying the forecast may prove inaccurate and are subject to significant risks and uncertainties that could cause actual results to differ materially from those forecasted. If our actual results are significantly below forecasted results, or if our expenses are greater than forecasted, we may not be able to pay the forecasted annual distribution or any distribution on our common units, which may cause the market price of our common units to decline materially.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, results of operations, liquidity, ability to meet our financial commitments, ability to make our planned capital expenditures and our cash available for distribution.

Our revenues, operating results, cash available for distribution, liquidity and ability to grow depend primarily upon the prices we receive for the natural gas, oil and NGL we sell. We require substantial expenditures to replace our natural gas, oil and NGL reserves, sustain production and fund our business plans, including our development and exploratory drilling efforts. Historically, the markets for natural gas, oil and NGL have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas, oil and NGL prices may result from relatively minor changes in the supply of or demand for natural gas, oil and NGL, market uncertainty and other factors that are beyond our control, including:

- worldwide and regional economic conditions impacting the supply and demand for oil, natural gas and NGLs;
- 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 war in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- actions of the Organization of the Petroleum Exporting Countries and its allies ("OPEC+"), including the ability and willingness of the members of OPEC+ and other exporting nations to agree to and maintain oil price and production controls;
- changes in seasonal temperatures, including the number of heating degree days during winter months and cooling degree days during summer months;
- the level of oil, natural gas and NGL exploration, development and production;
- the level of oil, natural gas and NGL inventories;
- the level of U.S. LNG exports;
- the impact on worldwide economic activity of an epidemic, outbreak or other public health events, such as COVID-19,
- prevailing prices on local price indexes in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and processing facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- the spot price of LNG on world markets;

- changes in ocean freight capacity, which could adversely impact LNG shipping capacity or lead to material interruptions in service or stoppages in LNG transportation;
- political and economic conditions in or affecting major LNG consumption regions or countries, particularly Asia and Europe;
- weather conditions and natural disasters, including those influenced by climate change;
- technological advances affecting energy consumption;
- the impact of energy conservation efforts;
- the price and availability of alternative fuels;
- activities that to restrict the exploration, development and production of oil and natural gas to minimize greenhouse gas ("GHG") emissions;
- speculative trading in oil and natural gas derivative contracts;
- increased end-user conservation;
- U.S. trade policies and their effect on U.S. oil and natural gas exports;
- expectations about future commodity prices; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes, including legislation or regulations addressing GHG emissions or requiring the reporting of GHG emissions or climate-related information.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements accurately. Lower commodity prices may reduce our operating margins, cash flow and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves or make acquisitions could be adversely affected. Also, using lower prices in estimating proved and probable reserves may result in a reduction in proved and probable reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower than current WTI and Henry Hub strip prices may adversely affect our drilling economics, cash flow and our ability to raise capital, which may require us to re-evaluate and postpone or substantially restrict our development program, and result in the reduction of some of our proved and probable undeveloped reserves and related PV-10. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, cash available for distribution, liquidity and ability to meet our financial commitments or cause us to delay our planned capital expenditures.

Currently, our producing properties are concentrated in the Anadarko Basin, 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 area 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, 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 or even longer, 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 or results of operations.

Our future financial condition and results of operations will depend on the success of our development, production and acquisition activities, which are subject to numerous risks beyond our control. For example, we cannot assure you that wells we drill will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil, natural gas and NGLs often involves unprofitable efforts from wells that do not produce sufficient oil, natural gas and NGLs to return a profit at then-realized prices after deducting drilling, operating and other costs. In addition, our cost of drilling, completing and operating wells is often uncertain.

Our decisions to develop or purchase prospects or properties will depend, in part, on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, 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 turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves."

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

- declines in oil, natural gas and NGL prices;
- increases in the cost of, and shortages or delays in the availability of, proppant, acid, equipment, services and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- capacity or pressure limitations on gathering systems, processing and treating facilities or other related midstream infrastructure;
- any future lack of available capacity on interconnecting transmission pipelines;
- delays imposed by, or resulting from, compliance with regulatory requirements, including limitations on freshwater sourcing, wastewater disposal, emissions of GHGs and hydraulic fracturing;
- pressure or irregularities in geological formations;
- limited availability of financing on acceptable terms;
- issues related to compliance with or liability arising under environmental laws and regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the air, surface and subsurface environment;
- compliance with contractual requirements;
- competition for surface locations from other operators that may own rights to drill at certain depths across portions of our leasehold;
- lack of available gathering facilities or delays in construction of gathering facilities;
- adverse weather conditions, such as hurricanes, lightning storms, flooding, tornadoes, snow or ice storms and changes in weather patterns;
- the availability and timely issuance of required governmental permits and licenses;
- title issues or legal disputes regarding leasehold rights; and
- other market limitations in our industry.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled certain drilling locations as an internal estimation of our future multi-year drilling activities on our existing acreage. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, availability and cost of capital, drilling and production costs, availability of drilling services and equipment, availability and cost of sand and other proppant used in hydraulic fracturing operations and acid used for acid stimulation, drilling results, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution and disposal systems, access to and availability of saltwater disposal systems, regulatory approvals, the cooperation of other working interest owners and other factors. Because of these uncertain factors, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil and natural gas from these or any other drilling locations. As such, our actual drilling activities may materially differ from those presently identified.

As a result of the limitations described in this prospectus, we may be unable to drill many of our identified locations. In addition, although we plan to fund our drilling program entirely with cash flow from operations, if our cash flows are less than we expect or we alter our drilling plans, we may be required to borrow more under our New Credit Facility than we expect or issue new debt or equity securities in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. See "— Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves." Any drilling activities we are able to conduct on these locations may not be successful, may not result in production or additions to our estimated proved and probable reserves and could result in a downward revision of our estimated proved and probable reserves, which in turn could have a material adverse effect on the borrowing base under our New Credit Facility or our future business and results of operations. Additionally, if we curtail or cancel our drilling program, we may be required to reduce our estimated proved and probable reserves, which could in turn reduce the borrowing base under our New Credit Facility.

Properties that we decide to drill may not yield oil and natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of geologic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

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 recoverable reserves, future oil and natural gas prices and their applicable differentials, development and operating costs, and potential liabilities, including environmental liabilities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices, but such a review may not reveal all existing or potential problems. Such assessments are inexact and inherently uncertain. 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 any groundwater contamination or pipe corrosion, when a review is performed. We also may be unable to obtain contractual indemnities from the seller for liabilities arising 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. For these reasons, the properties we have acquired or will acquire in the future may not produce as expected or may not increase our cash available for distribution.

The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.

As of June 30, 2023, approximately 7% of our total estimated proved reserves were classified as PUDs using SEC Pricing. Development of these PUDs may take longer and require higher levels of capital expenditures than we currently anticipate. Estimated future development costs relating to the development of our PUDs at June 30, 2023 are approximately $261.0 million over the next five years. Our ability to fund these expenditures is subject to a number of risks. See "— Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves." Delays in the development of our PUDs, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the PV-10 value of our estimated PUDs and future net cash flows estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify some of our PUDs as unproved reserves. Furthermore, there is no certainty that we will be able to convert our PUDs to developed reserves or that our PUDs will be economically viable or technically feasible to produce.

Further, SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. As a result, we may be required to reclassify certain of our PUDs if we do not drill those wells within the required five-year timeframe.

Part of our business strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Difficulties that we face while completing our wells include:

- the ability to fracture stimulate the planned number of stages with the planned amount of proppant;
- the ability to source acid for our acid stimulation completion techniques;
- the ability to run tools through the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. If our development and production results are less than anticipated, the return on our investment for a particular well or region may not be as attractive as we anticipated, and we could incur material write-downs of our undeveloped acreage and its value could decline in the future.

The marketability of our production is dependent upon gathering, treating, processing and transportation facilities, some of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues could decrease.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of gathering, treating, processing and transportation pipelines, plants and other midstream facilities, a significant portion of which is owned by third parties. Some of our oil and natural gas production is collected from the wellhead by third-party gathering lines and transported to a gas processing or treating facility or transmission pipeline. We do not control these third-party facilities and our access to them may be limited, curtailed or denied. Pipelines, plants, and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements, and curtailments of receipts or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. The third-party facilities may experience unplanned downtime or maintenance for a variety of reasons outside our control and our production could be materially negatively impacted as a result of such outages. Insufficient production from our wells in the properties we do not operate to support the construction of pipeline facilities by third parties or a significant disruption in the availability of our or third-party midstream facilities or other production facilities could adversely impact our ability to deliver to market or produce our natural gas and thereby causing a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement gathering, treating, processing or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

If third-party pipelines or other midstream facilities interconnected to our gathering systems become partially or fully unavailable, our revenues and cash flows and our ability to make cash distributions to our unitholders could be materially adversely affected.

Our gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, rail terminals and produced water disposal facilities. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable due to issues including, but not limited to, testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other hazards. In addition, we do not have interconnect agreements with all of these pipelines and other facilities and the agreements we do have may be terminated in certain circumstances and/or on short notice. If any of these pipelines or other midstream facilities become unavailable for any reason, or, if these third parties are otherwise unwilling to receive or transport the oil, natural gas and produced water that we gather and/or process, our revenues, cash flows and ability to make cash distributions to our unitholders could be materially adversely affected.

Reserve estimates depend on many assumptions that may turn out to 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 and natural gas 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. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze 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 and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary materially from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected and production declines may be greater than we estimate and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates of proved and probable reserves to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant change could materially affect the estimated quantities and present value of our reserves. Furthermore, our development plan calls for completing horizontal wells using tighter well spacing and acid stimulation, which may increase the risk that these wells interfere with production from existing or future wells in the same spacing section and horizon, which in turn may result in lower recoverable reserves. There can be no assurance that our reserves will ultimately be produced or that our proved undeveloped reserves will be developed within the periods anticipated.

You should not assume that the present values of future net cash flows from our reserves presented in this prospectus are the current market value of our estimated reserves. Actual future prices and costs may differ materially from those used in our present value estimates using SEC Pricing. If spot prices or future actual prices are below the prices used in our current reserve estimates, using those prices in estimating proved and probable reserves may result in a decrease in proved and probable reserve volumes due to economic limits. You should not assume that the standardized measure of proved reserves and PV-10 values of our estimated reserves are accurate estimates of the current fair value of our estimated oil, natural gas and NGL reserves.

Estimates of probable reserves, and the future cash flows related to such estimates, are inherently imprecise and are more uncertain than estimates of proved reserves and the future cash flows related to such estimates but have not been adjusted for risk due to such uncertainty. Because of such uncertainty, estimates of probable reserves, and the future cash flows related to such estimates, may not be comparable to estimates of proved reserves and the future cash flows related to such estimates and should not be summed arithmetically with estimates of proved reserves and the future cash flows related to such estimates. When producing an estimate of the amount of natural gas, NGLs and oil that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. All of our probable reserves as of June 30, 2023 were estimated using a deterministic method, which involves two distinct determinations: (i) an estimation of the quantities of recoverable oil and natural gas and (ii) an estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves uses the same generally accepted analytical procedures as are used in estimating proved reserves, namely production performance-based methods, material balance-based methods, volumetric-based methods and analogy. In the case of probable reserves, the recoverable reserves cannot be said to have a "high degree of confidence that the quantities will be recovered", but are "as likely as not to be recovered." The lower degree of certainty can come from several factors including: (1) direct offset production that does not meet an economic threshold, despite localized averages that do meet that threshold, (2) an increased distance from offset production to the probable location of over one mile but under three miles, (3) a perceived risk of communication or depletion from nearby producers, (4) a perceived risk of attempting new drilling or completion technologies that have not been used in direct offset production or (5) an uncertainty regarding geologic positioning that could affect recoverable reserves. When considering the factors referenced above, the lower degree of certainty of our probable reserves came from a combination of these factors. Many of the probable locations assigned in our reserve report as of June 30, 2023 had few uncertainties and resemble proved undeveloped locations except for their distance from commercial production. Other probable locations had uncertainties related to not only distance from commercial production, but also related to well spacing and development timing. In general, we did not book probable locations if there was geologic uncertainty or if there was not commercial production to support such locations.

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 June 30, 2023 were calculated under SEC rules using the unweighted arithmetic average first day of the month prices for the prior 12 months of $4.763/MMBtu for natural gas and $82.82/Bbl for oil at June 30, 2023, 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.

Unless we replace our produced reserves with acquired or developed new reserves, our reserves and production will decline, which would adversely affect our future cash flows, results of operations and cash available for distribution.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be materially and adversely affected.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas, secure trained personnel and raise additional capital.

Our ability to acquire additional oil and gas properties and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and gas industry. Many of our competitors possess and employ greater financial, technical and personnel resources than we do. Those companies may be able to pay more for oil and natural gas properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Those larger companies may also 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. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring natural gas properties, developing reserves, marketing our production, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

A portion of our estimated drilling locations are based on our management's internal estimates and were not based on evaluations prepared by Cawley, Gillespie & Associates Inc.

Approximately 665 of our 2,022 total identified drilling locations are on properties that we do not anticipate to operate and were based on our management's internal estimates and not based on evaluations of Cawley, Gillespie & Associates Inc., our independent reserve engineer. Nonetheless, management's internal estimates were based upon the same guidelines as used within the Cawley, Gillespie & Associates Inc. evaluation, being production performance-based methods, material balance-based methods, volumetric-based methods and analogy. As a result, these estimates have greater uncertainty than those identified drilling locations evaluated by Cawley, Gillespie & Associates Inc.

Our midstream services contracts are generally structured as short-term and long-term, fixed-fee contracts, which may negatively impact our operating margins and cash flow during periods of lower oil and natural gas prices.

We have entered into short-term and long-term, fixed-fee contracts with third parties for gathering, processing and transportation services, including four firm transportation contracts, three of which are fully utilized and one that is partially utilized, with the remainder released to other shippers or unutilized. The impact of the unutilized portion of this contract is assumed under the weighted average sales price in the reserves. The total liability as of June 30, 2023 under the firm transportation contracts is $10.6 million. In addition, under these short-term and long-term, fixed-fee arrangements, our gathering and processing expenses are generally fixed on a per unit basis for the term of the applicable contract and do not automatically adjust in response to a decline in oil and natural gas prices. In the event of a prolonged period of lower commodity prices, our revenue will decline while the per unit fees we pay for natural gas gathering, treating and compression services generally will not, which would negatively impact our operating margins and cash flow. In addition, during periods of depressed oil and natural gas prices, the market prices for such services may be lower than what we are contractually obligated to pay to our current third-party midstream service providers. Furthermore, to the extent certain future taxes or assessments are imposed on certain midstream assets we utilize, under certain circumstances we may be required by our midstream services contracts to reimburse the midstream service provider for such taxes or assessments, which could negatively affect our operating margins and cash flow. Our third-party midstream service providers are under no obligation to renegotiate their contracts with us. Our failure to obtain these services on competitive terms could materially harm our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We depend on Mach Resources to provide us services necessary to operate our business. If Mach Resources were unable or unwilling to provide these services, it would result in a disruption in our business that could have an adverse effect on our financial position, financial results and cash flow.

We do not directly employ directors, officers or employees. Pursuant to the MSA with Mach Resources, an entity that is wholly owned by Tom L. Ward and his family, all of our executive management personnel are employees of Mach Resources, and we use a significant number of Mach Resources' employees to operate our properties and provide us with general and administrative services. If Mach Resources were to become unable or unwilling to provide such services, we would need to develop these services internally or arrange for the services from another service provider. Developing the capabilities internally or by retaining another service provider could have an adverse effect on our business, and the services, when developed or retained, may not be of the same quality as provided to us by Mach Resources. Additionally, if the MSA were to terminate, we would lose our key personnel.

Certain factors could require us to write down the carrying values of our properties, including commodity prices decreasing to a level such that our future undiscounted cash flows from our properties are less than their carrying value.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, drilling and completion results, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash impairment charge to earnings. Lower commodity prices in the future could result in impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. We could experience further material write-downs as a result of other factors, including low production results or high lease operating expenses, capital expenditures or transportation fees.

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

The existence of a material title deficiency can render a lease worthless and adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title 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 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 Oklahoma and Texas 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.

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. In the future we may make acquisitions of assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

The success of completed acquisitions will depend on our ability to effectively integrate the acquired businesses 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. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our New Credit Facility will impose certain limitations on our ability to enter into mergers or combination transactions and to incur certain indebtedness, which could indirectly limit our ability to acquire assets and businesses.

Our development projects and acquisitions require substantial capital expenditures. We may be unable to obtain any required capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.

The oil and gas industry is capital-intensive. A number of factors could cause our cash flow to be less than we expect, including the results of our drilling and completion program. Moreover, our capital budgets are based on a number of assumptions, including expected elections by working interest partners, drilling and completion costs, midstream service costs, oil and natural gas prices, and drilling results, and are therefore subject to change. If our cash flows are less than we expect, we decide to pursue acquisitions, or we change our capital budgets, we may be required to borrow more under our New Credit Facility than we expect or issue debt or equity securities to consummate such acquisitions or fund our drilling and completion program. The incurrence of additional indebtedness, either through borrowings under our New Credit Facility, the issuance of additional debt securities or otherwise, would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund capital expenditures, our development plan, acquisitions and cash distributions to unitholders. 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 The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things: oil and natural gas prices; actual drilling results; the availability and cost of drilling rigs and labor and other services and equipment; the availability, cost and adequacy of midstream gathering, processing, compression and transportation infrastructure; and regulatory, technological and competitive developments.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which our production is sold;
- the amount of our proved reserves;
- the amount of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the amount of our operating expenses;
- cash settlements from our derivative activities;
- our ability to borrow under our New Credit Facility; and
- our ability to access the debt and equity capital markets or sell non-core assets.

If our revenues or the borrowing base under our New Credit Facility decrease as a result of lower commodity prices, operational difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to make acquisitions or sustain our operations 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. If cash flow generated by our operations or available borrowings under our New Credit Facility are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of the development of our properties, which in turn could lead to a decline in our reserves and production and could materially and adversely affect our business, financial condition and results of operations.

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, since March 2022, the Federal Reserve has raised its target range for the federal funds rate multiple times, and additional rate hikes may continue to occur. 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.

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

Historically, capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices and drilling activity in our areas of operation and other major shale basins throughout the United States. These cost increases result from a variety of factors beyond our control, such as increases in the cost of sand and other proppant used in hydraulic fracturing operations or acid used for acid stimulation, and steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flow 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. Furthermore, high oil prices have historically led to more development activity in oil-focused shale basins and resulted in service cost inflation across all U.S. shale basins, including our areas of operation. Higher levels of development activity in oil-focused shale basins have also historically resulted in higher levels of associated gas production that places downward pressure on natural gas prices. To the extent natural gas prices decline due to a period of increased associated gas production and we experience service cost inflation during such period, our cash flow, profitability and ability to make distributions to our unitholders may be materially adversely impacted.

The unavailability or high cost of drilling rigs, frac crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, frac crews, pipe and other equipment and supplies, including sand and other proppant used in hydraulic fracturing operations and acid used for acid stimulation, as well as for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with commodity prices or drilling activity in our areas of operation and in other shale basins in the United States, causing periodic shortages of supplies and needed personnel and rapid increases in costs. Increased drilling activity could materially increase the demand for and prices of these goods and services, and we could encounter rising costs and delays in or an inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to conduct our drilling and development activities, which could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs could have a material adverse effect on our cash flow and profitability.

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 six months ended June 30, 2023, two purchasers each accounted for more than 10% of our predecessor's revenue: Phillips 66 Company (52.0%) and NextEra Energy Marketing, LLC (16.7%). For the year ended December 31, 2022, three purchasers each accounted for more than 10% of our predecessor's revenue: Hinkle Oil and Gas Inc. (31.5%), NextEra Energy Marketing, LLC (17.0%) and Phillips 66 Company (16.9%). For the year ended December 31, 2021, four purchasers each accounted for more than 10% of our predecessor's revenue: Phillips 66 Company (33.5%), NextEra Energy Marketing, LLC (20.2%), Hinkle Oil and Gas Inc. (13.3%) and ONEOK Hydrocarbon L.P. (13.9%). No other purchaser accounted for more than 10% of our predecessor's revenue during these periods. We do not have long-term contracts with our customers; rather, we sell the substantial majority of our production 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 — 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 oil, 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.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

On a pro forma basis as of June 30, 2023, after giving effect to the Reorganization Transactions, the entry into our New Credit Facility and this offering and the use of proceeds therefrom, we expect to have no debt outstanding with $ million of availability under our New Credit Facility. In the future, we and our subsidiaries may incur substantial additional indebtedness (including secured indebtedness). Our New Credit Facility contains restrictions on the incurrence of additional indebtedness, and these restrictions will be subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial. Additionally, the New Credit Facility does permit us to incur certain amounts of additional indebtedness.

Although we expect to remain substantially debt free following consummation of the offering, our level of indebtedness, if any, could affect our operations in several ways, including the following:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our debt, thereby reducing the cash available to finance our operating and investing activities;

- limiting management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increasing our vulnerability to downturns and adverse developments in our business and industry;
- limiting our ability to raise capital on favorable terms;
- limiting our ability to raise available financing, make investments, lease equipment, sell assets and engage in business combinations;
- making us vulnerable to increases in interest rates;
- putting us at a competitive disadvantage relative to our competitors; and
- limiting our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities, due to covenants contained in our New Credit Facility, including financial covenants.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

The agreement governing our New Credit Facility contains a number of significant covenants, including restrictive covenants that will, subject to certain qualifications, limit our ability to, among other things:

- make certain payments, including paying dividends or distributions in respect of our equity;
- incur additional indebtedness;
- make loans to others;
- make certain acquisitions and investments;
- make or pay distributions on our common units, if an event of default or borrowing base deficiency exists;
- merge or consolidate with another entity;
- hedge future production or interest rates;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, our New Credit Facility will require us to maintain compliance with certain financial covenants.

The restrictions in the agreement governing our New Credit Facility also impacts our ability to obtain capital to withstand a downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our debt arrangements may impose on us.

A breach of any covenant in our New Credit Facility will result in a default under our credit agreement and an event of default if there is no grace period or if such default is not cured during any applicable grace period. An event of default, if not waived, could result in acceleration of the indebtedness outstanding under the applicable agreement and in an event of default with respect to, and an acceleration of, the indebtedness outstanding under any other debt agreements to which we are a party. Any such accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

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

Our New Credit Facility is expected to limit the amounts we can borrow up to a borrowing base amount, which the administrative agent in good faith and in accordance with its usual and customary procedures for evaluating oil and gas loans and related assets at that particular time and otherwise acting in its sole discretion, will determine and which will be approved by the required lenders or all lenders, as applicable in the case of an increase in the borrowing base, on a semi-annual basis based upon projected revenues from our natural gas properties, our commodity derivative contracts securing our loan and certain other information (including, without limitation, the status of title information with respect to the oil and gas properties and the existence of any other indebtedness, liabilities, fixed charges, cash flow, business, properties, prospects, management and ownership, hedged and unhedged exposure to price, price and production scenarios, interest rate and operating cost changes). In addition to the scheduled redeterminations, the Company and the required lenders may be expected to request unscheduled interim redeterminations of the borrowing base not more than once between scheduled redeterminations. Any increase in the borrowing base will require the consent of all lenders (other than defaulting lenders). If the requisite number of required lenders or all lenders, as applicable in the case of an increase in the borrowing base, do not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. We will be required to repay outstanding borrowings in excess of the borrowing base. The borrowing base will also automatically decrease upon (i) the issuance of certain debt and (ii) the sale or other disposition of borrowing base properties or midstream properties or the early termination of certain swap agreements if the aggregate fair market value of such properties sold or disposed of and the relevant swap agreements so terminated is in excess of % of the borrowing base then in effect. The borrowing base under our New Credit Facility will be $ million with an elected commitment amount of $ million.

In the future, we may not be able to access adequate funding under our New Credit Facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a borrowing base redetermination, or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover a defaulting lender’s portion. Furthermore, our borrowing base may be reduced if we sell assets in the future. Declines in commodity prices could result in a determination to lower the borrowing base and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions, make distributions to our unitholders or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our New Credit Facility will bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our business, financial condition and results of operations and cash available for distribution.

The credit risk of financial institutions could adversely affect us.

We have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies and deposit accounts held at regional banks. In addition, if any lender under our New Credit Facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender’s commitment under the credit agreement.

Some of the Company’s deposit accounts are held at regional banks. The recent high-profile bank failures involving Silicon Valley Bank, Signature Bank, and First Republic Bank have generated significant market volatility and, in particular, for regional banks. While the Department of the Treasury, the Federal Reserve, and the FDIC have made statements ensuring that depositors of recently failed banks would have access to their deposits, including uninsured deposit accounts, there is no guarantee that such actions will continue for future failed banks, including the regional banks that hold our deposit accounts.

Our ability to obtain financing on terms acceptable to us may be limited in the future by, among other things, increases in interest rates.

We require continued access to capital and our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. We may use our New Credit Facility to finance a portion of our future growth, and these factors could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Volatility in the global financial markets, significant losses in financial institutions' U.S. energy loan portfolios, or environmental and social concerns may lead to a contraction in credit availability impacting our ability to finance our operations or our ability to refinance our New Credit Facility or other outstanding indebtedness. An increase in interest rates could increase our interest expense and materially adversely affect our financial condition. A significant reduction in cash flow from operations or the availability of credit could materially and adversely affect our ability to carry out our development plan, our cash available for distribution and operating results.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we enter into derivative contracts for a portion of our projected oil and natural gas production, primarily consisting of swaps. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosure About Market Risk — Commodity price risk — Commodity derivative activities." Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received for the sale of our production; or
- there are issues regarding legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures, make payments on our indebtedness and make distributions to our unitholders, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties and oil and natural gas prices.

The cost to drill and complete oil and natural gas wells often increases in times of rising oil and natural gas prices. To the extent our drilling and completion costs increase, but our derivative arrangements limit the benefit we receive from increases in oil and natural gas prices, our margins could be limited, which could have a material adverse effect on our financial condition. In addition, the amount we pay in severance taxes is calculated without taking our derivative arrangements into account, and if our derivative arrangements limit the benefit we receive from increases in oil and natural gas prices, the effective tax rate we pay in severance taxes could increase.

Our derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty 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.

During periods of declining commodity prices our derivative contract receivable positions would generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our derivative contracts.

The failure of our hedge counterparties, significant customers or working interest holders to meet their obligations to us may adversely affect our financial results.

Our hedging transactions expose us to the risk that a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make such party unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. Any default by a counterparty to these derivative contracts when they become due could have a material adverse effect on our financial condition and results of operations.

Our ability to collect payments from the sale of oil and natural gas to our customers depends on the payment ability of our customer base, which includes several significant customers. If any one or more of our significant customers fail to pay us for any reason, we could experience a material loss. In addition, if any of our significant customers cease to purchase our oil and natural gas or reduce the volume of the oil and natural gas that they purchase from us, the loss or reduction could have a detrimental effect on our revenues and may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas.

We also face credit risk through joint interest receivables. Joint interest receivables arise from billing entities who own partial working interests in the wells we operate. Though we often have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings, the inability or failure of working interest holders to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Events outside of our control, including widespread public health crises, epidemics and outbreaks of infectious diseases such as COVID-19, or the threat thereof, and any related threats of recession and other economic repercussions 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.

Widespread public health crises, epidemics, and outbreaks of infectious diseases, which can give rise to a threat of recession and related economic repercussions can create significant volatility, uncertainty and turmoil in the global economy and oil and gas industry, as did COVID-19 during 2020 through the beginning of 2022. These variables are beyond our control and may have the effect of disrupting the normal operations of many businesses, including the temporary closure or scale-back of business operations and/or the imposition of either quarantine or remote work or meeting requirements for employees, either by government order or on a voluntary basis. While the effects of the COVID-19 outbreak have lessened, widespread public health crises, epidemics and outbreaks of infectious diseases spreading throughout the U.S. and globally, including from a renewed outbreak of COVID-19, could result in significant disruptions to our operations. The global economy, our markets and our business have been, and may continue to be, materially and adversely affected by widespread public health crises, epidemics and outbreaks of infectious diseases, which 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.

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. Inflation rose from 7.5% in January 2022 to a peak of 9.1% in June 2022 and then decreased to 6.5% in December 2022. In June 2023, inflation further decreased to 3.0%. 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. We also may face shortages of these commodities and labor, which may prevent us from fully 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.

Oil and gas exploration and production companies are frequently subject to litigation claims from landowners, royalty owners and other interested parties, particularly during periods of declining commodity prices.

Title to oil and gas properties is often unclear and subject to claims by third parties. Additionally, oil and gas companies are frequently subject to claims with respect to underpayment of royalties, environmental hazards and contested ownership of properties, especially during periods of declining commodity prices and therefore revenue and royalty payments. The oil and gas exploration and production business is especially susceptible to increased cost of capital, hedging losses and declining revenues which can result in defaults on third party obligations. These risk and others can result in the incurrence of significant attorney’s fees and other expenses incurred in the prosecution or defense of litigation.

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 maintain insurance against some, but not all, operating risks and losses. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our operations are subject to all of the risks associated with drilling for and producing oil, natural gas and NGLs and operating gathering and processing facilities including the possibility of:

- environmental hazards, such as releases of pollutants into the environment, including groundwater, surface water, soil and air contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- ruptures, fires and explosions;
- damage to pipelines, processing plants, compression assets, water infrastructure, and related equipment and surrounding properties caused by tornadoes, floods, freezes, fires and other natural disasters;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- personal injuries and death;

- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Any of these events could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims by government agencies or third parties 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; and
- repair and remediation costs.

These events may also result in curtailment or suspension of our gathering and processing facilities. A natural disaster or any event such as those described above affecting the areas in which we and our third-party customers operate could have a material adverse effect on our operations. Accidents or other operating risks could further result in loss of service available to us and our third-party customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on portions or all of our gathering facilities.

We may elect not to obtain insurance for certain of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, in some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, including for pollution and other environmental risks. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Extreme weather conditions and the physical risks of climate change could adversely affect our ability to conduct drilling activities in the areas where we operate and the operations of our gathering and processing facilities and have a negative impact on our business and results of operations.

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. If any such effects were to occur, they could adversely affect or delay demand for oil or natural gas products or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves, which may not be fully insured. For example, 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 wildfires and floods, in each case which may cause a loss of operational efficiency or production from temporary cessation of activity or lost or damaged facilities and equipment. Further, these types of interruptions could result in a decrease in the volumes supplied to our gathering systems, and delays and shutdowns caused by severe weather may have a material negative impact on the continuous operations of our gathering and processing facilities, including interruptions in service. These types of interruptions could negatively impact our ability to meet our contractual obligations to our third-party customers and thereby give rise to certain termination rights or other liabilities under our contracts. Such extreme weather conditions and events could also impact other areas of our operations, including the costs of insurance, 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. Given that our operations are concentrated exclusively in the Anadarko Basin, a number of our properties could experience any of the same weather conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more geographically diversified portfolio of properties. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning.

Our business is subject to climate-related transition risks, including evolving climate change legislation, fuel conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry, which could result in increased operating expenses and capital costs, financial risks and reduction in demand for oil and natural gas.

Increasing attention from governmental and regulatory bodies, investors, consumers, industry and other stakeholders on combating climate change, together with changes in consumer and industrial/commercial behavior, societal pressure on companies to address climate change, investor and societal expectations regarding voluntary climate-related disclosures, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons, and the use of products manufactured with, or powered by, hydrocarbons, may result in the enactment of climate change-related regulations, policies and initiatives at the government, regulator, corporate and/or investor community levels, including alternative energy requirements, new fuel consumption standards, energy conservation and emissions reductions measures and responsible energy development; technological advances with respect to the generation, transmission, storage and consumption of energy (including advances in wind, solar and hydrogen power, as well as battery technology); increased availability of, and increased demand from consumers and industry for, energy sources other than oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles); and development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services. These developments may in the future adversely affect the demand for products manufactured with, or powered by, petroleum products, as well as the demand for, and in turn the prices of, oil and natural gas products. Such developments may also adversely impact, among other things, our stock price and access to capital markets, and the availability to us of necessary third-party services and facilities that we rely on, which may increase our operational costs and adversely affect our ability to successfully carry out our business strategy. Climate change-related developments may also impact the market prices of or our access to raw materials such as energy and water and therefore result in increased costs to our business.

More broadly, the enactment of climate change-related legislation and regulatory initiatives may in the future result in increases in our compliance costs and other operating costs. For further discussion regarding the risks posed to us by climate change-related legislation and regulatory initiatives, see "— Climate change legislation or regulations restricting emissions of GHGs or requiring the reporting of GHG emissions or climate-related information could result in increased operating costs, impact the demand for the oil and natural gas we produce, and adversely affect our business."

Negative perceptions regarding the Company's industry and related reputational risks may also in the future adversely affect the Company's ability to successfully carry out the Company's business strategy by adversely affecting the Company's access to capital. There have been efforts in recent years, for example, to influence the investment community, including investment advisors, insurance companies, and certain sovereign wealth, pension and endowment funds and other groups, by promoting divestment of fossil fuel equities and pressuring lenders to limit funding and insurance underwriters to limit coverages to companies engaged in the extraction of fossil fuel reserves. Certain financial institutions and members of the investment community have shifted, and others may elect in the future to shift, some or all of their investment into non-fossil fuel related sectors. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Certain investment banks and asset managers based both domestically and internationally have announced that they are adopting climate change guidelines for their banking and investing activities. Institutional lenders who provide financing to energy companies, such as the Company, have also become more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. Ultimately, this could make it more difficult to secure funding for exploration and production activities or adversely impact the cost of capital for both the Company and its customers, and could thereby adversely affect the demand and price of the Company's securities. Limitation of investments in and financings for energy companies could also result in the restriction, delay, or cancellation of infrastructure projects and energy production activities.

More broadly, negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change or other sustainability-related matters, may also lead to increased reputational and litigation risk and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new laws, regulations, guidelines and enforcement interpretations targeting our industry. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations, and such activism could materially and adversely impact our ability to operate our business and raise capital. The foregoing factors may result in downward pressure on the stock prices of oil and gas companies, including the Company's, and cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. For example, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas, or claims alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customer. Although the Company is not a party to any such litigation, we could be named in actions making similar allegations, which could lead to costs and materially impact our financial condition in an adverse way.

Our operations are subject to stringent environmental laws and regulations that may affect our operations and expose us to significant costs and liabilities that could exceed current expectations.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, the release, disposal or discharge of materials into the environment, and occupational health and safety aspects of our operations. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated drilling activities; the restriction of types, quantities and concentrations of materials that can be released into the environment; the prohibition of noise-producing activities; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including threatened and endangered species habitats; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. 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. We may be required to make significant capital and operating expenditures or perform remedial or other corrective actions at our wells and properties to comply with the requirements of these environmental laws and regulations or the terms or conditions of permits issued pursuant to such requirements. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, 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 and limit our growth and revenue.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations (including plugging and abandonment obligations) and waste disposal practices. Spills or other releases of regulated substances, including such spills and releases that could 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 held strictly liable for the removal or remediation of previously released materials or property 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. For example, lawsuits in which landowners sue every operator in the chain of title for environmental damages to their property are not uncommon in states in which we operate. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In certain instances, citizen groups also have the ability to bring legal proceedings against us regarding our compliance with environmental laws, or to challenge our ability to receive environmental permits that we need to operate. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations or historical oil and natural gas production in our areas of operation, which have been producing oil in certain instances for several decades. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

The long-term trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, particularly in light of the Biden administration's focus on addressing climate change, resulting in increased costs of doing business and consequently affecting profitability. For example, in January 2021, President Biden signed an executive order directing the U.S. Department of the Interior ("DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed subject to certain limitations, although litigation over the leasing pause remains ongoing. As a result, it is difficult to predict if and when such areas may be made available for future exploration activities. Further, for example, on November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule imposes emissions reduction standards on both new and existing sources in the oil and natural gas industry, expands the scope of Clean Air Act ("CAA") regulation, and imposes emissions reductions targets to meet the stated goals of the U.S. federal administration. On November 11, 2022, the EPA issued the proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters." The EPA is currently expected to issue a final rule by August 2023. Further, in September 2021, President Biden publicly announced the Global Methane Pledge, an international pact that aims to reduce global methane emissions to at least 30% below 2020 levels by 2030, and in August 2022, President Biden signed the Inflation Reduction Act of 2022 into law, which incentivizes the reduction of methane emissions and would impose a fee on methane produced by petroleum and natural gas facilities in excess of a specified threshold, among other initiatives. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities 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 industry as well as our own results of operations, competitive position or financial condition.

To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Climate change legislation or regulations restricting emissions of GHGs or requiring the reporting of GHG emissions or climate-related information could result in increased operating costs, impact the demand for the oil and natural gas we produce, and adversely affect our business.

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply with such laws and regulations. In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment and in the absence of comprehensive federal legislation on GHG emission control, the EPA has adopted regulations pursuant to the CAA to monitor, report, and/or reduce GHG emissions from various sources. We cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions, such as by means of cap and trade programs. Cap and trade programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. At the international level, in April 2016, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, which resulted in an agreement intended to nationally determine their contributions and set GHG emission reduction goals every five years beginning in 2020. In November 2019, plans were formally announced for the U.S. to withdraw from the Paris Agreement with an effective exit date in November 2020. In February 2021, the current administration announced reentry of the U.S. into the Paris Agreement along with a new "nationally determined contribution" for U.S. GHG emissions that would achieve emissions reductions of at least 50% relative to 2005 levels by 2030. In September 2021, President Biden publicly announced the Global Methane Pledge, an international pact that aims to reduce global methane emissions to at least 30% below 2020 levels by 2030. To date, over 150 countries have joined the pledge. Various state and local governments have also vowed to continue to enact regulations to satisfy their proportionate obligations under the Paris Agreement.

Any legislation or regulatory programs addressing GHG emissions could increase the cost of consuming, and thereby reduce demand for, the natural gas we produce, and could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements, and to monitor and report on GHG emissions. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Moreover, incentives or requirements to conserve energy, use alternative energy sources, reduce GHG emissions in product supply chains, and increase demand for low-carbon fuel or zero-emissions vehicles, could reduce demand for the oil and natural gas we produce. The Inflation Reduction Act of 2022, for example, provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture and other programs directed at addressing climate change. 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.

Although it is not currently possible to predict how these executive orders, national commitments or any proposed or future GHG or climate change legislation or regulation promulgated by Congress, the states or multi- state regions and their respective regulatory agencies will impact our business, any legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business or on the assets we operate could result in increased compliance or operating costs or additional operating restrictions or reduced demand for our products, and could have a material adverse effect on our business, financial condition and results of operations. For further discussion of certain existing and proposed climate-related rules and regulations, see “Business and Properties — Legislative and regulatory environment.”

Increased scrutiny of ESG matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

In recent years, companies across all industries are facing increasing scrutiny from a variety of stakeholders, including investor advocacy groups, proxy advisory firms, certain institutional investors and lenders, investment funds and other influential investors and rating agencies, related to their ESG and sustainability practices. If we do not adapt to or comply with investor or other stakeholder expectations and standards on ESG matters as they continue to evolve, or if we are perceived to have not responded appropriately or quickly enough to growing concern for ESG and sustainability issues, regardless of whether there is a regulatory or legal requirement to do so, we may suffer from reputational damage and our business, financial condition and/or stock price could be materially and adversely affected. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital.

Further, our operations, projects and growth opportunities require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities and others. We may face pressure from stakeholders, many of whom are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability while at the same time remaining a successfully operating company. If we do not successfully manage expectations across these varied stakeholder interests, it could erode stakeholder confidence and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand and growth opportunities, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and difficulty securing investors and access to capital.

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, limit the areas in which we can operate, and reduce our oil and natural gas production, which could adversely affect our production and business.

Hydraulic fracturing is a common practice used to stimulate production of oil and/or natural gas from dense subsurface rock formations and is important to our business. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We and our third-party operators use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies or trigger seismic activity. Proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibiting the performance of well drilling in general or hydraulic fracturing in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

In addition, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act (“SDWA”) over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. The EPA also finalized rules under the Clean Water Act (“CWA”) in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Additionally, 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 certain activities associated with hydraulic fracturing may impact drinking water resources under some circumstances. In March 2016, the U.S. Occupational Safety and Health Administration issued a final rule to impose stricter standards for worker exposure to silica, which went into effect in June 2018 and applies to use of sand as a proppant for hydraulic fracturing. The U.S. Department of the Interior’s Bureau of Land Management (“BLM”) finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. Following years of litigation, the BLM rescinded this rule in December 2017. However, California and various environmental groups filed lawsuits in January 2018 challenging the BLM’s rescission of the rule and, in March 2020, the U.S. District Court for the Northern District of California upheld the BLM’s decision to rescind the rule. However, there is ongoing litigation regarding the BLM rules, and future implementation of these rules is uncertain at this time. On November 30, 2022, the BLM also issued a proposed rule to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. New laws or regulations that impose new obligations on, or significantly restrict hydraulic fracturing, could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable and increase our cost of doing business. Such increased costs and any delays or curtailments in our production activities could have a material adverse effect on our business, prospects, financial condition, results of operations and liquidity.

Legislation or regulatory initiatives intended to address the disposal of saltwater gathered from our drilling activities could limit our ability to produce oil and natural gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of saltwater gathered from our drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

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.

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 and/or habitats. The Endangered Species Act ("ESA") and (in some cases) comparable state laws were established to protect endangered and threatened species. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in material restrictions to land use and may materially delay or prohibit land access for natural gas development. The Trump administration issued rules that narrowed the definition of "habitat" and altered a policy in a way that made it easier to exclude territory from critical habitat. In October 2021, the Biden administration published two rules that reversed those changes, and in June and July 2022, the FWS issued final rules rescinding Trump-era regulations concerning the definition of "habitat" and critical habitat exclusions. The designation of previously unprotected species as threatened or endangered or new critical or suitable habitat designations in areas where we conduct operations could result in limitations or prohibitions on our operations and could adversely impact our business, and it is possible the new rules could increase the portion of our lease areas that could be designated as critical habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the United States. Permanent restrictions imposed to protect threatened or 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 or further changes to regulations could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and 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 or our customers to incur costs or take other measures which may adversely impact our business or operations.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments 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 Commodity Futures Trading Commission ("CFTC") to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swap contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The full impact of the Dodd-Frank Act's swap regulatory provisions and the related rules of the CFTC on our business will not be known until all of the rules to be adopted under the Dodd-Frank Act have been adopted and fully implemented and the market for derivatives contracts has adjusted. 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. 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 have implemented and continue to implement regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, which could have adverse effects on our operations similar to the possible effects on our operations of the Dodd-Frank Act's swap regulatory provisions and the rules of the CFTC.

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

Like many oil and gas companies, we are, or may be, from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters, alleged violations of federal or state securities laws and personal injury, environmental damage or property damage matters, in the ordinary course of our business. Additionally, members of our management and our directors may, from time to time, be involved in various legal and other proceedings against the Company naming those officers or directors as co-defendants. Such legal and regulatory 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 and affect the value of our common units. Accruals for such liability, penalties or sanctions may be insufficient, and 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. The defense of any legal proceedings against us or our officers or directors, could take resources away from our operations and divert management attention. As of the date of this prospectus, the Company is not aware of any material legal or environmental proceedings contemplated to be brought against the Company or its management.

Loss of our information and computer systems could adversely affect our business. Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, geologic 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 or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell natural gas and 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.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, 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. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

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.

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 will have control over all decisions related to our operations. Upon consummation of this offering, the Sponsor and certain members of management will own all of the membership interests in our general partner which will be in the same proportion to each other as their respective limited partner interest ownership in us. The Sponsor and members of management will also own an aggregate of approximately and , respectively, 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 to manage our general partner at the direction of the Sponsor and members of management. As a result of these relationships, conflicts of interest may arise in the future between the Sponsor, certain members of management in their capacities as members of our general partner and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand; provided, however, that upon our adoption of our code of business conduct, we would expect that any such member of our management, so long as they are an executive officer, will be required to avoid personal conflicts of interest and not compete against us, in each case unless approved by the Board. 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 Sponsor (excluding our general partner) to pursue a business strategy that favors us;
- The Sponsor is not limited in its 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 % 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.

Please read "Certain Relationships and Related Party Transactions" and "Conflicts of Interest and Duties."

Our partnership agreement does not restrict the Sponsor 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 the Sponsor's ability to compete with us and the Sponsor does 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. The Sponsor will be under no obligation to make any acquisition opportunities available to us. See "Conflicts of Interest and Duties."

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. 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 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; provided, however, the MSA will require our general partner to seek approval by the conflicts committee of the Board in connection with an amendment to the MSA that, in the reasonable discretion of our general partner, adversely affects our unitholders;
  - 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.

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 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 New 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 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 New 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 business strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

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. Please read "The Partnership Agreement — Non-Citizen Unitholders; Redemption."

Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, 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 Sponsor and certain members of management, as a result of their ownership of our general partner, and not by our unitholders. Please read "Management — Management of Mach Natural Resources" and "Certain Relationships and Related Party Transactions." 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 will have control over all decisions related to our operations. Since, upon consummation of this offering, affiliates of our general partner (including the Sponsor and certain members of management) collectively will own and control the voting of an aggregate of approximately % 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 Sponsor and certain members of management)). Assuming we do not issue any additional common units and the affiliates of our general partner (including the Sponsor and certain members of management) do not transfer any of their common units, the affiliates of our general partner (including the Sponsor and certain members of management) will generally have the ability to control 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 Sponsor and certain members of management) 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 will own sufficient units upon completion of this offering to be able to prevent the removal of our general partner. The vote of the holders of at least 66⅔% of all outstanding units voting together as a single class is required to remove our general partner. Following consummation of this offering, affiliates of our general partner (including the Sponsor and certain members of management) will own approximately of our outstanding common 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 Sponsor or certain members of management which controls our general partner, from transferring all or a portion of their ownership interests 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.

Once our common units are publicly traded, the Existing Owners may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

After the sale of the common units offered hereby the Sponsor will own common units, or approximately % of our limited partner interests, and, the management will own common units, or approximately % of our limited partner interests. 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 Sponsor and certain members of management. Once our common units are publicly traded, 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 % 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. At the closing of this offering, affiliates of our general partner will own approximately % of our common units. For additional information about this call right, please read "The Partnership Agreement — Limited Call Right."

Our partnership agreement will designate 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 will provide 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 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. For additional information about the exclusive forum provision of our partnership agreement, please read "The Partnership Agreement — Applicable Law; Forum, Venue and Jurisdiction."

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf pursuant to the MSA will reduce cash available for distribution to our unitholders. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. The amount and timing of such reimbursements will be determined by our general partner.

At the closing of this offering, we and our general partner will also enter into a MSA with Mach Resources pursuant to which Mach Resources will manage and perform all aspects of our oil and gas and midstream operations and other general and administrative functions in exchange for reimbursement of certain expenses. On a monthly basis, we will reimburse our general partner and its affiliates for certain expenses they incur and payments they make on our behalf pursuant to the MSA. 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, 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. The reimbursement of expenses to our general partner and its affiliates will reduce the amount of cash available for distribution to our unitholders. For the six months ended June 30, 2023, we paid $39.0 million to Mach Resources, which consists of $3.6million for an annual management fee and $35.4 million for reimbursements of its costs and expenses under the existing management services agreements among Mach Resources and the Mach Companies.

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

We intend to apply to list our common units on the NYSE under the symbol "MNRE." Because we will be a publicly traded limited 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. Please read "Management — Management of Mach Natural Resources."

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.

Please read "The Partnership Agreement — Limited Liability" for a discussion of the implications of the limitations of liability on a unitholder.

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.

Our unitholders may have limited liquidity for their common units, a trading market may not develop for the common units and our unitholders may not be able to resell their common units at the initial public offering price.

Prior to this offering, there has been no public market for the common units. After this offering, there will be publicly traded common units. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. Our unitholders may not be able to resell their common units at or above the initial public offering price. Additionally, a lack of liquidity would likely result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

If our common unit price declines after the initial public offering, our unitholders could lose a significant part of their investment.

The initial public offering price for the common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. 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 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. 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.

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, which may be up to five full fiscal years, 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 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.

We intend 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 will 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. As a newly public company, we will not be required to make our first annual assessment of our internal controls over financial reporting pursuant to Section 404 until the year following our first annual report to be filed with the SEC, but we will be required to disclose material changes made to our internal controls and procedures on a quarterly basis. We will not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls over financial reporting until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. 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. Please read "The Partnership Agreement — Election to be Treated as a Corporation."

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

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses that we did not incur prior to this 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 will 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 will be affected by the costs associated with being a public company.

Prior to this offering, we have not filed reports with the SEC. Following this offering, we will become subject to the public reporting requirements of the Exchange Act. We expect these rules and regulations to increase certain of our legal and financial compliance costs and to make 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 expect to 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 this 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 will be 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

In addition to reading the following risk factors, prospective unitholders should read "Material U.S. Federal Income Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of our common units.

Our tax treatment depends on our status as a partnership for U.S. 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 U.S. 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 U.S. 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 U.S. 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 U.S. 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 U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. 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 Oklahoma, Kansas and Texas, 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 U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations. From time to time, members of Congress propose and consider substantive changes to the existing U.S. 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 U.S. federal income tax laws or 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 U.S. federal income tax purposes or otherwise adversely affect our business, financial condition or results of operations. Any such changes to U.S. federal income tax laws 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 U.S. 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 common 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 common units on the first day of each month, instead of on the basis of the date a particular common 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 U.S. 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, our unitholders may be required to pay U.S. 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 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 accretion expense and intangible drilling costs. 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, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from U.S. 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 marginal 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. 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, amortization and accretion 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 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 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 U.S. federal income taxes, our 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 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 Oklahoma, Kansas and Texas. Oklahoma and Kansas 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 entity-level income tax. It is the responsibility of each unitholder to file its own U.S. 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 many of the relative fair market value estimates ourselves. 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.

USE OF PROCEEDS

We estimate that the net proceeds to us from this offering, after deducting estimated underwriting discounts and commissions and estimated offering expenses payable by us, will be approximately $ million, assuming an initial public offering price of $ per common unit (which is the midpoint of the estimated offering price range shown on the cover page of this prospectus). We intend to use the expected net proceeds of approximately $ million from this offering to repay the Existing Credit Facilities with the remainder used for general partnership purposes.

If and to the extent the underwriters exercise their option to purchase additional common units, the number of common units purchased by the underwriters pursuant to such exercise will be issued to the public. If the underwriters exercise their option to purchase additional common units in full, the additional net proceeds would be approximately $ million. The net proceeds from any exercise of such option will be used for general partnership purposes. Please read "Underwriting."

As of June 30, 2023, we had $174 million of outstanding borrowings under our Existing Credit Facilities, as adjusted for the Reorganization Transactions, which have maturities in May 2024, September 2024 and September 2026. Borrowings outstanding under the Existing Credit Facilities bore an effective interest rate between 8.3% and 8.5% as of June 30, 2023. Borrowings under the Existing Credit Facilities have been incurred primarily to fund our capital expenditures and acquisitions. The Existing Credit Facilities will be repaid in full and terminated in connection with this offering. For more information on our Existing Credit Facilities, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt agreements — Existing Credit Facilities."

A $1.00 increase or decrease in the assumed initial public offering price of $ per common unit would cause the net proceeds from this offering, after deducting underwriting discounts and estimated offering expenses payable by us, to increase or decrease, respectively, by approximately $ million. In addition, we may also increase or decrease the number of common units we are offering. Each increase of million common units offered by us, together with a concurrent $1.00 increase in the assumed public offering price of $ per common unit, would increase net proceeds to us from this offering by approximately $ million. Similarly, each decrease of million common units offered by us, together with a concurrent $1.00 decrease in the assumed initial offering price of $ per common unit, would decrease the net proceeds to us from this offering by approximately $ million.

The sources and use of our proceeds may differ from those set forth above. The foregoing represents our current intentions with respect to the use and allocation of the net proceeds of this offering based upon our present plans and business condition, but our management will have significant flexibility and discretion in applying the net proceeds. The occurrence of unforeseen events or changed business conditions could result in application of the net proceeds of this offering in a manner other than as described in this prospectus.

CAPITALIZATION

The following table shows:

- our predecessor's historical capitalization as of June 30, 2023;
- our capitalization as adjusted to give effect to the Reorganization Transactions; and
- as further adjusted to give effect to (i) entry into the New Credit Facility and (ii) this offering and the application of the net proceeds as described under "Use of Proceeds."

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, our historical and unaudited pro forma condensed combined financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations." For a description of the pro forma adjustments, please read our unaudited pro forma condensed combined financial statements.

	As of June 30, 2023		
	Predecessor Historical	As Adjusted	As Further Adjusted
	(In thousands)		
Cash and cash equivalents	$ 48,846	$ 109,608	$
Long-term debt:			
Existing Credit Facilities[(1)]	$ 91,900	$ 174,000	$
New Credit Facility	$ —	$ —	$
Members'/partners' capital/net equity:			
Common equity held by the public	$ —	$ —	$
Common equity held by the Existing Owners	$ 689,527	$	$
Total members'/partners' capital/net equity	$ 689,527	$	$
Total capitalization	$ 781,427	$	$

(1) As of August 1, 2023, we had approximately $174 million of outstanding borrowings under our Existing Credit Facilities. For more information on our Existing Credit Facilities, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt agreements — Existing Credit Facilities."

DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the net tangible book value per common unit after this offering. Net tangible book value is our total tangible assets less total liabilities. Assuming an initial offering price of $ per common unit (the midpoint of the price range set forth on the cover of this prospectus), on a pro forma basis as of June 30, 2023, after giving effect to the Reorganization Transactions, this offering of common units and the application of the related net proceeds, our net tangible book value would have been $ million, or $ per common unit. Purchasers of common units in this offering will experience substantial and immediate accretion in net tangible book value per common unit for accounting purposes, as illustrated in the following table:

Assumed initial public offering price per common unit		$
Pro forma net tangible book value per common unit before this offering[1]	$	
Decrease in net tangible book value per common unit attributable to purchasers in the offering		
Less: Pro forma net tangible book value per common unit after this offering[2]		
Immediate accretion in net tangible net book value per common unit to purchasers in the offering[3][4]		$

(1) Determined by dividing the pro forma net tangible book value of our net assets immediately prior to the offering by the number of common units held by the Existing Owners, after giving effect to the Reorganization Transactions.

(2) Determined by dividing our pro forma as adjusted net tangible book value, after giving effect to the application of the net proceeds of this offering, by the total number of units to be outstanding after this offering after giving effect to the Reorganization Transactions.

(3) If the initial public offering price were to increase or decrease by $1.00 per common unit, then accretion in net tangible book value per common unit would equal $ and $, respectively.

(4) Because the total number of units outstanding following the consummation of this offering will be impacted by any exercise of the underwriters' option to purchase additional common units and any net proceeds from such exercise will be retained by us, there will be a change to the accretion in net tangible book value per common unit to purchasers in the offering due to any such exercise of the underwriters' option to purchase additional common units.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by the Existing Owners and by the purchasers of common units in this offering upon the closing of the transactions contemplated by this prospectus after giving effect to the Reorganization Transactions:

	Units Acquired		Total Consideration	
	Number	Percent	Amount	Percent
		(in thousands)		
Existing Owners		%		%
Purchasers in the offering[1]		%		%
Total		100.0%		100.0%

(1) Total consideration is after deducting underwriting discounts and estimated offering expenses.

OUR CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with the factors and assumptions upon which our cash distribution policy is based, which are included under the heading "— Assumptions and Considerations" below. In addition, you should read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business.

General

Our 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 costs, 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. Generally, we define available cash as the sum of our (i) cash on hand at the end of a quarter after the payment of our costs and expenses and the establishment of cash reserves, (ii) cash on hand on the date on which our general partner determines the amount of cash available for distribution, which we refer to as 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, and (iii) if our general partner so determines, cash on hand at the date of determination resulting from working capital borrowings made after the end of the quarter. We may, but are under no obligation to, borrow funds to make quarterly distributions to 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 pay the distribution at the current level. Further, we may rely upon our cash reserves (including the net proceeds that we will retain from this offering) and external financing sources, including borrowings under our New Credit Facility (under which no amounts will be outstanding at the closing of this offering) and the issuance of debt and equity securities, to fund future acquisitions and other expenditures. We also plan to continue our practice of opportunistically entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations, and therefore reduce volatility in quarterly distributions. Because we are not subject to an entity-level federal income tax, we expect to have more cash to distribute to our unitholders than would be the case if we were subject to such federal income tax.

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 will 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 and cash equivalents 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 and cash equivalents 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.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

Although our partnership agreement requires that we distribute all of our available cash quarterly, there is no guarantee that we will make quarterly cash distributions from our available cash to our unitholders at the level currently estimated or at all, and we have no legal obligation to do so. Our current cash distribution policy is subject to certain restrictions, as well as the considerable discretion of our general partner in determining the amount of our available cash each quarter. The following factors will affect our ability to make cash distributions, as well as the amount of any cash distributions we make:

- Our cash distribution policy may be subject to restrictions on distributions under the New Credit Facility or other debt agreements that we may enter into in the future. Specifically, the New Credit Facility contains financial tests and covenants that we must satisfy. These financial tests and covenants are described in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt agreements — New Credit Facility." Should we be unable to satisfy these restrictions, or if a default occurs under the New Credit Facility, we would be prohibited from making cash distributions to our unitholders notwithstanding our stated cash distribution policy. Any future indebtedness may contain similar or more stringent restrictions.

- The amount of cash that we distribute and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. Specifically, our general partner will have the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of or increase in those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy. Any decision to establish cash reserves made by our general partner in good faith will be binding on our unitholders. If our general partner does not set aside sufficient cash reserves, or make sufficient cash capital expenditures to maintain the current production levels over the long-term of our oil and natural gas properties, we will be unable to pay any cash distributions from cash generated from operations. We are unlikely to be able to sustain our current level of distributions without making accretive acquisitions or capital expenditures that maintain the current production levels of our oil and natural gas properties. Decreases in commodity prices from current levels will adversely affect our ability to pay distributions.

- Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including Mach Resources, for all direct and indirect expenses they incur 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, 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 in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of cash available to pay cash distributions to our unitholders.

- Although our partnership agreement requires us to distribute all of our available cash each quarter, our partnership agreement, including the provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may 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 affiliates of our general partner). At the closing of this offering, the affiliates of our general partner (including the Sponsor and certain members of management) will own approximately % of our outstanding common units. For more information, please read "The Partnership Agreement — Amendment of the Partnership Agreement."

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner.

- Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our unitholders due to a number of factors, including decreases in commodity prices, decreases in our oil and natural gas production, or increases in our general and administrative expenses, principal and interest payments on our outstanding debt, tax expenses, working capital requirements or anticipated cash needs.

- If and to the extent our cash available for distribution materially declines, we may reduce our quarterly distribution in order to service or repay our debt or fund maintenance or growth capital expenditures.

- We will not have a minimum quarterly distribution. Furthermore, none of our limited partner interests, including those held by the Existing Owners, will be subordinate in right of payment to the common units sold in this offering.

- Our general partner may reduce our distributions if action is taken by our general partner as described under “The Partnership Agreement — Election to be treated as a Corporation” that results in our becoming taxable as a corporation or otherwise subject to taxation as an entity for federal income tax purposes. In such an event, the distribution levels may be reduced to account for any current and future estimated tax liabilities we would incur as a corporation. The distributions will also be proportionately adjusted in the event of any distribution, combination or subdivision of common units in accordance with the partnership agreement. Please read “Provisions of Our Partnership Agreement Relating to Cash Distributions.”

Our Partnership Agreement Requires That We Distribute All of Our Available Cash, Which Could Limit Our Ability to Grow

Our partnership agreement requires us to distribute all of our available cash to our unitholders on a quarterly basis. As a result, our growth may not be as fast as the growth of businesses that reinvest all of their available cash to expand ongoing operations. Further, we may rely upon our cash reserves (including the net proceeds that we will retain from this offering) and external financing sources, including borrowings under the New Credit Facility (under which no amounts will be outstanding at the closing of this offering) and the issuance of debt and equity securities, to fund future acquisitions and other capital expenditures. To the extent we require external sources of capital to fund our growth and are unable to access such sources, the requirement in our partnership agreement to distribute all of our available cash and our current cash distribution policy may impair our ability to grow. The New Credit Facility limits, and any future debt agreements may limit, our ability to incur additional debt, including through the issuance of debt securities. Please read “Risk Factors — Risks Related to Our Business — Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.” To the extent we issue additional units, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our cash distributions per unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to our common units, and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such additional units. If we incur additional debt to finance our business strategy, we will have increased interest expense, which in turn will reduce the available cash that we have to distribute to our unitholders. Please read “Risk Factors — Risks Related to Our Business — Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.”

Unaudited Pro Forma Cash Available for Distribution for the Year Ended December 31, 2022and the Twelve Months Ended June 30, 2023

On a pro forma basis, assuming we had completed this offering on January 1, 2022, our cash available for distribution for the year ended December 31, 2022 and the twelve months ended June 30, 2023 would have been approximately $ million and $ million, respectively. This amount would have been sufficient to pay a cash distribution of $ per unit per quarter ($ on an annualized basis) during the year ended December 31, 2022, and a cash distribution of $ per unit per quarter ($ on an annualized basis) during the twelve months ended June 30, 2023.

The unaudited pro forma financial data does not give pro forma effect to the incremental general and administrative expenses that we expect to incur annually as a result of being a publicly traded partnership. We estimate that these incremental general and administrative expenses initially will be approximately $ million per year. Such incremental general and administrative expenses are not reflected in our historical or pro forma financial statements.

The pro forma financial statements, from which pro forma cash available for distribution is derived, do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. Furthermore, cash available for distribution is a cash accounting concept, while our unaudited pro forma financial statements have been prepared on an accrual basis. We derived the amounts of pro forma cash available for distribution stated above in the manner described in the table below. As a result, the amount of pro forma cash available for distribution should only be viewed as a general indication of the amount of cash available for distribution that we might have generated had we been formed and completed the transactions contemplated in this prospectus in earlier periods.

The following table illustrates, on an unaudited pro forma basis for the year ended December 31, 2022 and the twelve months ended June 30, 2023, the amount of available cash that would have been available for distribution to our unitholders, assuming in each case that this offering had been consummated on January 1, 2022.

Mach Natural Resources
Unaudited Pro Forma Cash Available for Distribution

	Pro Forma Year Ended December 31, 2022	**Pro Forma Twelve Months Ended June 30, 2023**
	(in thousands, except per unit amounts)	
Net Income	**$**	**$**
Interest expense		
Depreciation, depletion and amortization		
Unrealized (gain) loss on derivative settlements		
Equity-based compensation expense		
Loss on contingent consideration		
(Gain) loss on sale of assets		
Adjusted EBITDA[(1)]	**$**	**$**
Net Income	**$**	**$**
Interest expense		
Depreciation, depletion and amortization		
Unrealized (gain) loss on derivative settlements		
Equity-based compensation expense		
Loss on contingent consideration		
(Gain) loss on sale of assets		
Settlement of asset retirement obligations		
Cash interest expense, net		
Development costs		
Settlement of contingent consideration		
Change in accrued realized derivative settlements		
Cash Available for Distribution[(2)]	**$**	**$**
Pro Forma Annualized Distributions Per Unit	$	$
Pro Forma Estimated Annual Cash Distributions:		
Distributions on common units held by purchasers in this offering		
Distributions on common units held by our Existing Owners		
Total estimated annual cash distributions	$	$

(1) Adjusted EBITDA is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.

(2) Cash available for distribution is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.

Estimated Cash Available for Distribution for the Twelve Months Ending June 30, 2024

The financial forecast presents, to the best of our knowledge and belief, our expected results of operations, Adjusted EBITDA and cash available for distribution for the twelve months ending June 30, 2024. Based upon the assumptions and considerations set forth in the table below, we estimate that we will generate $ million in cash available for distribution for the twelve months ending June 30, 2024, which would be sufficient to pay cash distributions of $ per common unit. The number of outstanding common units on which we have based such belief does not include any common units that may be issued under the long-term incentive plan that our general partner is expected to adopt prior to the closing of this offering, including the expected award of phantom units (based on the mid-point of the price range set forth on the cover of this prospectus) to certain executives and key employees. Furthermore, the financial forecast assumes that we do not make any acquisitions of properties during the twelve months ending June 30, 2024.

The table below under "— Our Estimated Cash Available for Distribution" reflects our judgment, as of the date of this prospectus, of conditions we expect to exist and the course of action we expect to take in order to be able to be able to generate cash available for distribution in the amount of $ per common unit, or $ million in the aggregate for the twelve months ending June 30, 2024. The assumptions discussed below under "— Assumptions and Considerations" are those that we believe are significant to our ability to generate the requisite Adjusted EBITDA. Based on such assumptions, we believe our actual results of operations and cash flow will be sufficient to generate the Adjusted EBITDA necessary to pay the forecasted aggregate annualized cash distribution. We can, however, give you no assurance that we will generate this amount. There will likely be differences between our estimated Adjusted EBITDA and our actual results, and those differences could be material. If we fail to generate the estimated Adjusted EBITDA contained in our forecast, our annualized cash distribution to all of our unitholders may be less than expected. We can give you no assurance that our assumptions will be realized or that we will generate any available cash, in which event we will not be able to pay quarterly cash distributions from our available cash on our common units.

While we do not, as a matter of course, make public projections as to future sales, earnings or other results, our management has prepared the prospective financial information that is the basis of our estimated Adjusted EBITDA below to substantiate our belief that we will have sufficient cash to pay the forecasted cash distribution on all of our common units for twelve months ending June 30, 2024. This forecast is a forward-looking statement and should be read together with our historical financial statements and the accompanying notes included elsewhere in this prospectus and "Management's Discussion and Analysis of Financial Condition and Results of Operations." The accompanying prospective financial information was not prepared with a view toward complying with the published guidelines of the SEC or the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, is substantially consistent with those guidelines and was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the assumptions and considerations on which we base our belief that we can generate Adjusted EBITDA necessary for us to pay cash distribution on all of our outstanding common for the twelve months ending June 30, 2024 equal to $ per common unit. Readers of this prospectus are cautioned not to place undue reliance on this prospective financial information. Please read "— Assumptions and Considerations," including the sensitivity analysis included therein.

The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, our management. Grant Thornton LLP has not compiled, examined or performed any procedures with respect to the accompanying prospective financial information and, accordingly, Grant Thornton LLP does not express any opinion or any other form of assurance with respect thereto. The Grant Thornton LLP reports included in the registration statement relate to our historical financial information. It does not extend to the prospective financial information and should not be read to do so.

When considering our financial forecast, you should keep in mind the risk factors and other cautionary statements under "Risk Factors." Any of the risks discussed in this prospectus, to the extent they are realized, could cause our actual results of operations to vary significantly from those that would enable us to generate the Adjusted EBITDA necessary to pay the forecasted aggregate annualized cash distribution on all of our outstanding common units for the twelve months ending June 30, 2024.

We are providing the table below under "— Our Estimated Cash Available for Distribution" to supplement our historical financial statements and in support of our belief that we will have sufficient available cash to pay the forecasted aggregate annualized cash distribution on all of our outstanding common units for the twelve months ending June 30, 2024. Please read below under "— Assumptions and Considerations" for further information about the assumptions we have made for the financial forecast.

We do not undertake any obligation to release publicly the results of any future revisions we may make to this prospective financial information or to update this prospective financial information to reflect events or circumstances after the date of this prospectus. Therefore, you are cautioned not to place undue reliance on this information.

Our Estimated Cash Available for Distribution

The following table shows how we calculate estimated available cash for the twelve months ending June 30, 2024 and for each quarter during that twelve-month period that would be available for distribution to our unitholders. All of the amounts for the twelve months ending June 30, 2024 in the table below are estimates. The assumptions that we believe are relevant to particular line items in the table below are explained in the corresponding footnotes and in "— Assumptions and Considerations."

Neither our independent registered public accounting firm nor any other independent registered public accounting firm has compiled, examined or performed any procedures with respect to the forecasted financial information contained herein, nor has it expressed any opinion or given any other form of assurance on such information or its achievability, and it assumes no responsibility for such forecasted financial information.

Our independent registered public accounting firm's reports included elsewhere in this prospectus relate to our audited historical financial statements. These reports do not extend to the table and the related forecasted information contained in this section and should not be read to do so.

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	Three Months Ending September 30, 2023	Three Months Ending December 31, 2023	Three Months March 31, 2024	Three Months Ending June 30, 2024	Twelve Months Ending June 30, 2024
	(in thousands, except per unit amounts) (unaudited)				
Estimated Net Income[(1)]	$	$	$	$	$
Interest expense, net					
Depreciation, depletion and amortization					
Unrealized (gain) loss on derivative settlements[(2)]					
Equity-based compensation expense					
Loss on contingent consideration					
(Gain) loss on sale of assets[(3)]					
Estimated Adjusted EBITDA[(4)]	$	$	$	$	$
Estimated Net Income[(1)]	$	$	$	$	$
Interest expense					
Depreciation, depletion and amortization					
Unrealized (gain) loss on derivative settlements					
Equity-based compensation expense					
Loss on contingent consideration					
(Gain) loss on sale of assets					
Settlement of asset retirement obligations					
Cash interest expense, net					
Development costs					
Settlement of contingent consideration					
Change in accrued realized derivative settlements					
Estimated Cash Available for Distribution[(5)]	$	$	$	$	$
Estimated Cash distribution per unit	$	$	$	$	$
Estimated cash distributions[(6)]**:**					
Distributions on common units held by purchasers in this offering ( )	$	$	$	$	$
Distributions on common units held by the Existing Owners ( )	$	$	$	$	$
Total estimated annual cash distributions	$	$	$	$	$

(1) Includes the forecasted effect of cash settlements of commodity derivative instruments. This amount does not include unrealized commodity derivative gains (losses), as such amounts represent non-cash items and cannot be

reasonably estimated in the forecast period.

(2) Does not include an estimate of unrealized derivative (gain)/loss because the forecast period assumes the commodity prices set forth below under "— Assumptions and Considerations — Operations and Revenue — Prices" remain constant during the period. For additional information regarding the impact of changes in commodity prices, please see "— Sensitivity Analysis" below.

(3) Does not include estimated non-cash (gain)/loss, which cannot be accurately forecasted for future periods.

(4) Adjusted EBITDA is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.
(5) Cash available for distribution is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.
(6) The number of outstanding common units assumed herein does not include any common units that may be issued under the long-term incentive plan that our general partner is expected to adopt prior to the closing of this offering.

Assumptions and Considerations

Based upon the specific assumptions outlined below, we expect to generate cash available for distribution for the twelve months ending June 30, 2024 of approximately $ million.

While we believe that these assumptions are reasonable in light of management's current expectations concerning future events, the forecasted estimates underlying these assumptions are inherently uncertain and are subject to significant business, economic, regulatory, environmental and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate. If our assumptions are not correct, the amount of actual cash available to pay distributions could be substantially less than the amount we currently estimate, in which event the market price of our common units may decline substantially. When reading this section, you should keep in mind the risk factors and other cautionary statements described under "Risk Factors" and "Forward-Looking Statements." Any of the risks discussed in this prospectus could cause our actual results to vary significantly from our estimates.

Operations and Revenue

Production. 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. Our existing production will naturally decline over time as the applicable reservoir is depleted. Our decline rate for our oil and gas properties over the next four quarters is currently estimated to be approximately %.

The following table presents historical production volumes for our properties on a pro forma basis for the Mach Companies for the year ended December 31, 2022 and the twelve months ended June 30, 2023 and on a forecasted basis for the twelve months ending June 30, 2024:

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ending June 30, 2024
Annual production:			
Oil and condensate (MBbl)	5,982	6,612	
Natural gas (MMcf)	70,947	77,255	
Natural gas liquids (MBbl)	4,246	4,234	
Total (MBoe)	**22,053**	**23,721**	
Average net daily production:			
Oil and condensate (MBbl/d)	16.39	18.11	
Natural gas (MMcf/d)	194.38	211.66	
Natural gas liquids (MBbl/d)	11.63	11.60	
Total (MBoe/d)	**60.42**	**64.99**	

We estimate that our total oil and natural gas production for the twelve months ending June 30, 2024 will be MBoe/d as compared to 60 MBoe/d on a pro forma basis for the year ended December 31, 2022 and 65 MBoe/d on a pro forma basis for the twelve months ended June 30, 2023. For the month ended June 30, 2023, our net production was approximately 68 MBoe/d. We intend to maintain our forecasted production level of MBoe/d for the twelve months ending June 30, 2024 with cash generated from operations.

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 December 31, 2020 through June 30, 2023, prices for crude oil and natural gas reached a high of $123.64 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.47 per Bbl and $1.74 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 bases under our Existing Credit Facilities, which are redetermined semi-annually.

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. The differentials to published oil and natural gas prices are based upon our analysis of the historic price differentials for production from the mineral interests with consideration given to gravity, quality and transportation and marketing costs that may affect these differentials. There is no assurance that these assumed differentials will occur. The table below illustrates the relationship between average oil, natural gas and NGLs realized sales prices and average NYMEX prices as of June 30, 2023, on a pro forma basis for the Mach Companies for the year ended December 31, 2022 and the twelve months ended June 30, 2023, as well as our forecast for the twelve months ending June 30, 2024.

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ending June 30, 2024
Average oil sales prices (Bbl):			
Average daily NYMEX-WTI oil price	$ 94.33	$ 81.00	$
Differential to NYMEX-WTI oil (excluding derivatives)	(0.78)%	(0.51)%	%
Realized oil sales price (excluding derivatives)	$ 93.60	$ 80.58	$
Realized oil sales price (including derivatives)	$ 78.94	$ 75.34	$
Average natural gas sales prices (Mcf):			
Average daily NYMEX-Henry Hub natural gas price	$ 6.54	$ 4.81	$
Differential to NYMEX-Henry Hub natural gas (excluding derivatives)	(5.07)%	(7.87)%	%
Realized natural gas sales price (excluding derivatives)	$ 6.21	$ 4.43	$
Realized natural gas sales price (including derivatives)	$ 5.09	$ 3.99	$
Average natural gas liquids sales prices (Bbl):			
Average daily NYMEX-WTI oil price	$ 94.33	$ 81.00	$
Percentage of NYMEX-WTI oil price (excluding derivatives)	41.18%	36.46%	%
Realized natural gas liquids sales price (excluding derivatives)	$ 38.85	$ 29.53	$
Realized natural gas liquids sales price (including derivatives)	$ 38.85	$ 29.53	$

Hedging Activities. 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. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosure About Market Risk — Commodity price risk — Commodity derivative activities" for more information.

As of the date of this prospectus, our commodity derivative contracts will cover MBbl, or approximately %, of our forecasted total oil production of MBbl, MBbl, or approximately %, of our forecasted total NGL production of MBbl, and Mcf, or approximately %, of our forecasted total natural gas production of Mcf, for the twelve months ending June 30, 2024. Our commodity derivative contracts consist of swap agreements based upon NYMEX-WTI prices and NYMEX-Henry Hub prices. The table below shows the volumes and prices covered by the commodity derivative contracts for the twelve months ending June 30, 2024. For purposes of our forecast, we have assumed that we will not enter into additional natural gas or oil derivative contracts during the forecast period, although we may do so on an opportunistic basis if market conditions are favorable. See "Risk Factors — Risks Related to Our Business — Our derivative activities could result in financial losses or could reduce our earnings."

	Swaps	
	Volume per Day	Weighted Avg. Price
Oil:		
July 2023 – June 2024 (Bbl/d)		$
% of Forecasted Production	%	
Natural Gas:		
July 2023 – June 2024 (MMBtu/d)		$
% of Forecasted Production	%	

Operating Revenues and Realized Commodity Derivative Gains. The following table illustrates the primary components of operating revenues and realized commodity derivative gains on a pro forma basis for the year ended December 31, 2022 and the twelve months ended June 30, 2023 and on a forecasted basis for the twelve months ending June 30, 2024:

(in thousands)	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ending June 30, 2024
Oil:			
Oil revenues (excluding the effects of derivative instruments)	$ 559,881	$ 532,782	$
Realized oil derivative instruments gain (loss)	(87,672)	(34,655)	
Total	$ 472,209	$ 498,127	$
Natural gas:			
Natural gas revenues (excluding the effects of derivative instruments)	$ 440,571	$ 342,601	$
Realized natural gas derivative instruments gain (loss)	(79,380)	(34,297)	
Total	$ 361,191	$ 308,304	$
Natural gas liquids:			
Natural gas liquids revenue (excluding the effects of derivative instruments)	$ 164,968	$ 125,039	$
Realized natural gas liquids derivative instruments gain (loss)	—	—	
Total	$ 164,968	$ 125,039	$
Total:			
Operating revenues	$ 1,165,420	$ 1,000,422	$
Realized derivative instruments gain (loss)	(167,052)	(68,952)	
Operating revenue and realized commodity derivative instruments losses	$ 998,368	$ 931,470	$

Midstream Revenues. Our midstream revenue is generated from owned gathering and compression systems and processing plants. The Company charges a gathering, compression, processing rate per MMBtu transported through the gathering system and processing plant. The Company also gathers and disposes of salt water from producing wells through an owned pipeline system and disposal wells. The Company charges a fixed rate per barrel of water for disposal. The following table summarizes midstream revenues on a pro forma basis for the year ended December 31, 2022 and the twelve months ended June 30, 2023 and on a forecasted basis for the twelve months ending June 30, 2024:

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ended June 30, 2024
Midstream revenue (in thousands)	$ 44,832	$ 38,235	$

Costs and Expenses

Development Costs. Our estimated development costs for the twelve months ending June 30, 2024 of $ million represent our estimate of the annual capital expenditures necessary to achieve our forecasted production level of MBoe/d for the twelve months ending June 30, 2024.

Gathering and Processing Expense. Gathering and processing expense consists primarily of gathering fees and processing fees. Gathering and processing costs are recognized when change of control of the natural gas we sell occurs at the tailgate of the processing plant. This expense can also fluctuate based on acquisitions, commodity prices, and overall product mix. We evaluate gathering and processing on a per Boe basis to monitor costs to ensure that they are at acceptable levels. The following table summarizes gathering and processing expense on a pro forma basis for the year ended December 31, 2022 and the twelve months ended June 30, 2023 and on a forecasted basis for the twelve months ending June 30, 2024:

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ended December 31, 2023
Gathering and processing expense (in thousands)	$ 87,887	$ 80,989	$
Gathering and processing expense (per Boe)	$ 3.99	$ 3.41	$

Lease Operating Expenses. The following table summarizes lease operating expenses on an aggregate basis and on a per Boe basis for the year ended December 31, 2022, pro forma and the twelve months ended June 30, 2023, pro forma, and on a forecasted basis for the twelve months ending June 30, 2024:

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ended June 30, 2024
Lease operating expenses (in thousands)	$ 145,267	$ 170,394	$
Lease operating expenses (per Boe)	$ 6.59	$ 7.18	$

We estimate that our lease operating expenses for the twelve months ending June 30, 2024 will be approximately $ million. Lease operating expenses consist of expenses incurred for the operation and maintenance of wells and related equipment. On a pro forma basis, for the year ended December 31, 2022 and the twelve months ended June 30, 2023, and, on a forecasted basis, for the twelve months ended June 30, 2024, lease operating expenses were $ million, $ million and $ million, respectively.

Production Taxes. Production taxes consist primarily of severance taxes. Severance taxes are paid on produced oil and natural gas based on a percentage of 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 evaluate production taxes on a percentage of revenue basis to monitor costs to ensure that they are at acceptable levels. This expense can also fluctuate based on acquisitions, commodity prices, and overall product mix. The following table summarizes production taxes on a pro forma basis for the year ended December 31, 2022 and the twelve months ended June 30, 2023 and on a forecasted basis for the twelve months ending June 30, 2024:

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ended June 30, 2024
Production taxes (in thousands)	$ 65,194	$ 53,681	$
Production taxes (% of oil, natural gas and NGL sales)	5.6%	5.4%	%

Midstream Operating Expense. Our midstream operating expense is generated from expenses incurred in the operation of our owned gathering and compression systems and processing plants. The Company also incurs expenses related to the gathering and disposal of salt water from producing wells through an owned pipeline system and disposal wells. The following table summarizes midstream operating expense on a pro forma basis for the year ended December 31, 2022 and the twelve months ended June 30, 2023 and on a forecasted basis for the twelve months ending June 30, 2024:

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ended June 30, 2024
Midstream operating expense (in thousands)	$ 15,618	$ 14,186	$

General and Administrative Expenses. General and administrative expenses consist primarily of personnel related costs, professional fees and services and general office expenses and are partially offset by certain reimbursements of overhead expenses. In connection with the consummation of this offering, we expect to incur additional costs related to being a public company. However, we do not expect to experience a material change in our cash cost structure, except as may be affected by our recent property acquisitions, the volatility of commodity prices, increased expenses as a publicly traded partnership, the effects of our commodity derivative contracts, and the effects of impairment on our producing properties. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting the Comparability of Our Financial Condition and Results of Operations." The following table summarizes general and administrative expenses on a pro forma basis for the year ended December 31, 2022 and the twelve months ended June 30, 2023 and on a forecasted basis for the twelve months ending June 30, 2024:

	Pro Forma Year Ended December 31, 2022	Pro Forma Twelve Months Ended June 30, 2023	Forecasted Twelve Months Ended June 30, 2024
General and administrative expenses (in thousands)	$ 19,278	$ 20,163	$
General and administrative expenses (per Boe)	$ 0.87	$ 0.85	$

Interest Expense. Interest expense is primarily the result of borrowings on our New 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.

Regulatory, Industry and Economic Factors

Our forecast for the twelve months ending June 30, 2024 is based on the following significant assumptions related to regulatory, industry and economic factors:

- There will not be any new federal, state or local regulation of portions of the energy industry in which we operate, or any interpretation of existing regulations, that will be materially adverse to our business;
- There will not be any material nonperformance or credit-related defaults by suppliers, customers or vendors, or shortage of skilled labor;
- All supplies and commodities necessary for production and sufficient transportation will be readily available;
- There will not be any major adverse change in commodity prices or the energy industry in general;
- There will not be any material accidents, releases, weather-related incidents, unscheduled downtime or similar unanticipated events, including any events that could lead to force majeure under any of our marketing agreements;
- There will not be any adverse change in the markets in which we operate resulting from supply or production disruptions, reduced demand for our product or significant changes in the market prices for our product; and
- Market, insurance, regulatory and overall economic conditions will not change substantially.

Sensitivity Analysis

Our ability to generate sufficient cash from operations to pay cash distributions to our unitholders is a function of two primary variables: (i) production volumes; and (ii) commodity prices. In the tables below, we illustrate the effect that changes in either of these variables, while holding all other variables constant, would have on our ability to generate sufficient cash from our operations to pay the forecasted cash distributions on our outstanding common units for the twelve months ending June 30, 2024.

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 that have interdependent effects on the potential outcome.

Production Volume Changes

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 shows estimated Adjusted EBITDA under production levels of 80%, 100% and 120% of the production level we have forecasted for the twelve months ending June 30, 2024. The estimated Adjusted EBITDA amounts shown below are based on the assumptions used in our forecast.

	Percentage of Forecasted Net Production		
	80%	**100%**	**120%**
	(in thousands, except per unit amounts)		
Forecasted net production:			
Oil (MBbl)			
Natural gas (MMcf)			
Natural gas liquids (MBbl)			
Total (MBoe)			
Oil (MBbl/d)			
Natural gas (MMcf/d)			
Natural gas liquids (MBbl/d)			
Total (MBoe/d)			
Forecasted prices:			
NYMEX-WTI oil price (per Bbl)	$	$	$
Realized oil price (per Bbl) (excluding derivatives)			
Realized oil price (per Bbl) (including derivatives)			
Realized natural gas liquids price (per Bbl) (excluding derivatives)			
Realized natural gas liquids price (per Bbl) (including derivatives)			
NYMEX-Henry Hub natural gas price (per MMBtu)	$	$	$
Realized natural gas price (per Mcf) (excluding derivatives)			
Realized natural gas price (per Mcf) (including derivatives)			
Estimated Net Income[(1)]	**$**	**$**	**$**
Interest expense, net			
Depreciation, depletion and amortization			
Unrealized (gain) loss on derivative settlements[(2)]			
Equity-based compensation expense			
Loss on contingent consideration			
(Gain) loss on sale of assets[(3)]			
Estimated Adjusted EBITDA[(4)]			
Settlement of asset retirement obligations			
Cash interest expense, net			
Development costs			
Settlement of contingent consideration			
Change in accrued realized derivative settlements			
Estimated Cash Available for Distribution[(5)]	$	$	$

(1) Includes the forecasted effect of cash settlements of commodity derivative instruments. This amount does not include unrealized commodity derivative gains (losses), as such amounts represent non-cash items and cannot be reasonably estimated in the forecast period.

(2) Does not include an estimate of unrealized derivative (gain)/loss because the forecast period assumes the commodity prices set forth below under "— Assumptions and Considerations — Operations and Revenue — Prices" remain constant during the period. For additional information regarding the impact of changes in commodity prices, please see "— Commodity Price Changes" below.
(3) Does not include estimated non-cash (gain)/loss, which cannot be accurately forecasted for future periods.
(4) Adjusted EBITDA is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.
(5) Cash available for distribution is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.

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, while maintaining a conservative financial profile. 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" for a discussion of these and other risks affecting our proved reserves and production.

Commodity Price Changes

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 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. While there is a risk we may not be able to realize the full benefits of rising prices, these hedging activities are intended to limit our exposure to product price volatility and to maintain stable cash flows.

The following table shows estimated Adjusted EBITDA under various assumed NYMEX-WTI oil and NYMEX-Henry Hub natural gas prices for the twelve months ending June30, 2024. For the twelve months ending June 30, 2024, we have assumed that commodity derivative contracts will cover (i) MBbl, or approximately % of our estimated total oil production from proved reserves for the twelve months ending June 30, 2024, at a weighted average floor price of $ per Bbl, (ii) per barrel, or approximately % of our estimated total NGL production from proved reserves for the twelve months ending June 30, 2024, at a weighted average floor price of $ per barrel and (iii) MMBtu, or approximately % of our estimated total natural gas production from proved reserves for the twelve months ending June 30, 2024, at a weighted average floor price of $ per MMBtu. In addition, the estimated Adjusted EBITDA amounts shown below are based on forecasted realized commodity prices that take into account assumptions based on our average historical NYMEX commodity price differentials as set forth in our June 30, 2023 reserve report. We have assumed no changes in our production based on changes in prices. The estimated Adjusted EBITDA amounts shown below are based on forecasted realized commodity prices that take into account our average NYMEX commodity price differential assumptions.

	Percentage of Forecasted Prices		
	80%	**100%**	**120%**
	(in thousands, except per unit amounts)		
Forecasted net production:			
Oil and condensate (MBbl)			
Natural gas (MMcf)			
Natural gas liquids (MBbl)			
Total (MBoe)			
Oil and condensate (MBbl/d)			
Natural gas (MMcf/d)			
Natural gas liquids (MBbl/d)			
Total (MBoe/d)			
Forecasted prices:			
NYMEX-WTI oil price (per Bbl)	$	$	$
Realized oil price (per Bbl) (excluding derivatives)			
Realized oil price (per Bbl) (including derivatives)			
Realized natural gas liquids price (per Bbl) (excluding derivatives)			
Realized natural gas liquids price (per Bbl) (including derivatives)			
NYMEX-Henry Hub natural gas price (per MMBtu)	$	$	$
Realized natural gas price (per Mcf) (excluding derivatives)			
Realized natural gas price (per Mcf) (including derivatives)			
Estimated Net Income[(1)]	**$**	**$**	**$**
Interest expense, net			
Depreciation, depletion and amortization			
Unrealized (gain) loss on derivative settlements[(2)]			
Equity-based compensation expense			
Loss on contingent consideration			
(Gain) loss on sale of assets[(3)]			
Estimated Adjusted EBITDA[(4)]			
Settlement of asset retirement obligations			
Cash interest expense, net			
Development costs			
Settlement of contingent consideration			
Change in accrued realized derivative settlements			
Estimated Cash Available for Distribution[(5)]	$	$	$

(1) Includes the forecasted effect of cash settlements of commodity derivative instruments. This amount does not include unrealized commodity derivative gains (losses), as such amounts represent non-cash items and cannot be reasonably estimated in the forecast period.
(2) Does not include an estimate of unrealized derivative (gain)/loss because the forecast period assumes the commodity prices set forth below under "— Assumptions and Considerations — Operations and Revenue — Prices" remain constant during the period.
(3) Does not include estimated non-cash (gain)/loss, which cannot be accurately forecasted for future periods.
(4) Adjusted EBITDA is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.
(5) Cash available for distribution is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.

If NYMEX oil, NGLs and natural gas prices decline, our estimated Adjusted EBITDA would not decline proportionately for two reasons: (1) the effects of our commodity derivative contracts; and (2) production taxes, which are calculated as a percentage of our oil, NGLs and natural gas revenues, excluding the effects of our commodity derivative contracts, and which decrease as commodity prices decline. Furthermore, we have assumed no decline in estimated production or oil, NGLs and natural gas operating costs during the twelve months ending June 30, 2024. However, over the long-term, a sustained decline in prices would likely lead to a decline in production and operating costs, as well as a reduction in our realized oil, NGLs and natural gas prices. Therefore, the foregoing table is not illustrative of all of the potential effects of changes in commodity prices for periods subsequent to June 30, 2024.

PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Distributions of Available Cash

General

Our partnership agreement requires that, within 60 days after the end of each quarter (other than the fourth quarter) and within 90 days after the end of the fourth quarter, beginning with the quarter ending , we distribute all of our available cash to unitholders of record on the applicable record date. We will adjust the amount of our cash distribution for the period from the closing of this offering through , based on the actual length of that period.

Definition of Available Cash

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 will 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 and cash equivalents 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 and cash equivalents 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.

Methods of Distribution

We intend to distribute available cash to our unitholders, pro rata. Our partnership agreement permits, but does not require, us to borrow funds to make distributions to our unitholders. Accordingly, there is no guarantee that we will pay any distribution on the units in any quarter.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future acquire common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Distributions of Cash Upon Liquidation

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment (or establishing a reserve for payment) of our creditors. We will distribute any remaining proceeds to our unitholders, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The selected historical consolidated financial data set forth below as of and for each of the years ended December 31, 2022 and 2021 have been derived from our predecessor's audited consolidated financial statements included elsewhere in this prospectus. The selected historical consolidated financial data set forth below as of June 30, 2023 and for the six months ended June30, 2023 and 2022 are derived from our unaudited financial statements and related notes included elsewhere in this prospectus.

The selected unaudited pro forma financial data as of June30, 2023 and for the six months ended June30, 2023 are derived from the unaudited pro forma condensed financial statements of Mach Natural Resources included elsewhere in this prospectus, which reflect the historical results of our predecessor, BCE-Mach LLC and BCE-Mach II LLC on a pro forma basis to give effect to the following transactions, which are described in further detail below, as if they had occurred on June 30, 2023, for pro forma balance sheet purposes, and on January 1, 2022, for pro forma statements of operations purposes:

- the Reorganization Transactions as described in "— Reorganization Transactions, Partnership Structure and New Credit Facility" elsewhere in this prospectus summary; and
- the issuance and sale by us to the public of common units in this offering and the application of the net proceeds as described in "Use of Proceeds."

  Contemporaneously with the closing of this offering, we expect to use the proceeds of this offering to pay down the balances of the Existing Credit Facilities. We also expect to enter into a New Credit Facility contemporaneously with the closing of this offering. The New Credit Facility (under which no amounts will be outstanding at the closing of this offering) is expected to have a total facility size of $ million, an initial borrowing base of $ million and available capacity of $ million.

We have not given pro forma effect to the incremental general and administrative expenses that we expect to incur annually as a result of being a publicly traded partnership.

The unaudited pro forma historical financial data are presented for illustrative purposes only and are not necessarily indicative of the financial position that would have existed or the financial results that would have occurred if this offering and the Reorganization Transactions had occurred on the dates indicated, nor are they necessarily indicative of the financial position or results of our operations in the future. The pro forma adjustments, as described in the notes to the unaudited pro forma condensed combined financial statements, are preliminary and based upon currently available information and certain assumptions that our management believes are reasonable. The selected historical consolidated financial data are qualified in their entirety by, and should be read in conjunction with, the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section included in this prospectus and the consolidated financial statements and related notes and other financial information included in this prospectus. Among other things, those historical financial statements and unaudited pro forma condensed combined financial statements include more detailed information regarding the basis of presentation for the following information. Historical results are not necessarily indicative of results that may be expected for any future period.

You should read the following table in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations," our historical financial statements and our unaudited pro forma condensed combined financial statements and the notes thereto included elsewhere in this prospectus. Among other things, those historical financial statements and the unaudited pro forma condensed combined financial statements include more detailed information regarding the basis of presentation for the following information.

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(in thousands, except per unit amounts)	Predecessor Historical				Mach Natural Resources Pro Forma	
	Six Months Ended June 30,		Year Ended December 31,		Six Months Ended June 30,	Year Ended December 31,
	2023	2022	2022	2021	2023	2022
Statement of Operations Data:						
Revenues:						
Oil, natural gas, and NGL sales	$ 312,613	$ 408,442	$ 860,388	$ 397,500	$ 399,686	$ 1,165,420
Midstream revenue	13,318	19,883	44,373	31,883	13,531	44,832
Loss (gain) on oil and natural gas derivatives, net	15,742	(72,857)	(67,543)	(67,549)	22,618	(113,322)
Product sales	17,421	47,960	100,106	30,663	17,421	100,106
Total operating revenues	$ 359,094	$ 403,428	$ 937,414	$ 392,497	$ 453,256	$ 1,197,036
Operating Expenses:						
Gathering and processing expense	$ 17,510	$ 20,812	$ 47,484	$ 27,987	$ 33,430	$ 87,887
Lease operating expense	60,615	39,592	95,941	45,391	87,439	145,267
Midstream operating expense	5,538	6,976	15,157	12,248	5,761	15,618
Cost of product sales	15,575	44,958	94,580	28,687	15,575	94,580
Production taxes	15,526	22,675	47,825	21,165	20,003	65,194
Depreciation, depletion, amortization and accretion expense – oil and natural gas	58,095	29,374	84,070	37,537	72,117	119,359
Depreciation and amortization expense – other	2,793	2,008	4,519	3,148	3,171	5,445
General and administrative	9,905	13,648	25,454	60,927	11,750	19,278
Total operating expenses	$ 185,557	$ 180,043	$ 415,030	$ 237,090	$ 249,246	$ 552,628
Operating income	$ 173,537	$ 223,385	$ 522,384	$ 155,407	$ 204,010	$ 644,408
Other income (expenses):						
Interest expense	$ (3,789)	$ (1,876)	$ (4,852)	$ (1,656)	$ —	$ —
Other (expense) income, net	(245)	1,121	(691)	1,023	(4,966)	(1,083)
Loss on contingent considerations	—	—	—	(16,400)	—	—
Total other expenses	$ (4,034)	$ (755)	$ (5,543)	$ (17,033)	$ (4,966)	$ (1,083)
Net income	$ 169,503	$ 222,630	$ 516,841	$ 138,374	$ 199,044	$ 643,325
Net income per limited partner unit:						
Basic	$	$	$	$	$	$
Diluted	$	$	$	$	$	$
Weighted average number of limited partner units outstanding (basic and diluted):						
Basic						
Diluted						
Other Financial Data:						
Adjusted EBITDA[(1)]	$ 227,261	$ 276,408	$ 594,429	$ 248,617	$ 255,709	$ 714,305
Cash Available for Distribution[(2)]	$ 35,308	$ 159,701	$ 300,944	$ 184,445	$ 45,632	$ 405,888
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 275,145	$ 227,936	$ 553,542	$ 198,462		
Investing activities	$ (187,812)	$ (212,951)	$ (372,660)	$ (194,743)		
Financing activities	$ (67,904)	$ (27,236)	$ (210,737)	$ (4,584)		
Balance Sheet Data (at period end):						
Total assets	$ 979,312		$ 887,441	$ 525,379	$ 1,458,331	
Total long-term liabilities	$ 150,354		$ 141,570	$ 117,241	$ 115,143	
Members'/Partners' capital	$ 689,527		$ 593,230	$ 278,699	$ 1,139,866	

(1) Adjusted EBITDA is a non-GAAP financial measure, please see "Prospectus Summary — Non-GAAP Financial Measures" above.

(2) Cash available for distribution is a non-GAAP financial measure, please see “Prospectus Summary — Non-GAAP Financial Measures” above.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the "Selected Historical and Pro Forma Financial and Operating Data" and the audited and unaudited historical financial statements and related notes of BCE-Mach III (our predecessor), BCE-Mach and BCE-Mach II, as well as the unaudited pro forma financial statements included elsewhere in this prospectus. Unless otherwise indicated, the historical financial information in this "Management's Discussion and Analysis of Financial Condition and Results of Operation" reflects the historical financial results of our predecessor, and each of BCE-Mach and BCE-Mach II, on an individual basis and does not include the results of, or give pro forma effect to, the offering and the Reorganization Transactions described in "Prospectus Summary — Reorganization Transactions, Partnership Structure and New Credit Facility.*" Where indicated, certain financial information and operating data of our predecessor, BCE-Mach and BCE-Mach II are presented on a pro forma combined basis to give effect to the Reorganization Transactions.*

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance, which may affect the Mach Companies' future operating results and financial position. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Actual results and the timing of the events could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGLs, production volumes, estimates of proved and probable reserves, capital expenditures, economic, inflationary and competitive conditions, drilling results, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this prospectus, particularly under "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.

Our Company

We are an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas. Our assets are located throughout Western Oklahoma, Southern Kansas and the panhandle of Texas and consist of approximately 4,500 gross operated PDP wells. We view our assets in two groupings, our Focus Drilling Area and our Legacy Producing Assets. We define our "Focus Drilling Area" assets as all of our horizontal properties that are located in Kingfisher and Logan Counties, Oklahoma, and we define our "Legacy Producing Assets" as all of our legacy producing properties which are not in the Focus Drilling Area.

Within our operating areas, our assets are prospective for multiple formations, most notably the Oswego, Meramec/Osage and Mississippi Lime formations. Our experience in the Anadarko Basin and these formations allows us to generate significant cash available for distribution from these low declining assets in a variety of commodity price environments. We also own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure. Our midstream assets enhance the value of our properties by allowing us to optimize pricing, increase flow assurance and eliminate third-party costs and inefficiencies. In addition, our owned midstream systems generate third-party revenue.

Market Outlook

Our financial results depend on many factors, particularly commodity prices and our ability to find, develop and market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand. The oil and natural gas industry is cyclical and commodity prices are highly volatile and we expect continued and increased pricing volatility in the crude oil and natural gas markets. Oil prices have been affected by increased demand, domestic supply reductions, OPEC control measures and market disruptions resulting from the Russia-Ukraine war and sanctions on Russia. For example, during the period from December 31, 2020 through June 30, 2023, prices for crude oil and natural gas reached a high of $123.64 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.47 per Bbl and $1.74 per MMBtu, respectively. Starting in 2022, NYMEX oil and natural gas futures prices strengthened following the reduction of pandemic-related restrictions and increased OPEC+ cooperation. During the first quarter of 2023, the price of crude oil decreased as the global oil market saw higher inventory levels; however, prices remained above the 10-year average from 2010 through 2019. The increase in inventory levels was followed by an early June announcement from OPEC+ oil producers to further reduce oil output. The Energy Information Administration ("EIA") forecasts global oil inventories to fall slightly in each of the next five quarters and projects these draws will put upward pressure on crude oil prices, notably in late-2023 and early-2024. Also during the first quarter of 2023, natural gas prices remained above the 10-year range, despite declining significantly in the quarter as milder weather eased demand for natural gas heating, allowing storage levels to increase above historical averages in the United States and Europe. The EIA projects that the U.S. benchmark Henry Hub natural gas spot price to rise in the summer months due to rising natural gas use in the electric power sector and flattening production growth, which together contribute to storage injections that are less than the five-year average from 2018 through 2022 in the coming months.

Further, 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 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 7.5% in January 2022 to a peak of 9.1% in June 2022 and then decreased to 6.5% in December 2022. In June 2023, inflation further decreased to 3.0%. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience cost increases in our operations, including costs for drill rigs, workover rigs, tubulars and other well equipment, as well as increased labor costs. We continue to evaluate actions to mitigate supply chain and inflationary pressures and work 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 may be insufficient. Further, 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.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our operations, including the following sources of our revenue, principal components of our cost structure and other financial metrics:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs;
- lease operating expense ("LOE");
- Adjusted EBITDA; and
- cash available for distribution.

Sources of Our Revenue

Our oil and gas revenue is derived from the sale of our oil and natural gas production and the sale of NGLs that are extracted from our natural gas during processing, and in addition, our derivative instruments may result in a loss or gain in any given period depending on commodity prices for such period. Our midstream infrastructure not only allows us to eliminate certain third-party costs and increase efficiencies for gathering and processing a large portion of our production, but generates revenue from third-parties as well.

Net production volumes

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through drilling wells in our properties in the Oswego formation as well as low-risk acquisitions when economical to do so. 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. Please read "Risk Factors — Risks Related to the Oil and Natural Gas Industry and Our Business" for a discussion of these and other risks affecting our proved reserves and production.

Realized prices

The NYMEX WTI and Henry Hub futures prices are widely used benchmarks in the pricing of domestic and imported oil, and natural gas, respectively, in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI and NYMEX Henry Hub prices as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the ability to transport crude oil to the Cushing, Oklahoma transport hub and refineries. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds.

The following table presents our predecessor's average realized commodity prices for the periods specified below. Prices are before the effects of derivative settlements except where noted below.

	Six Months Ended June 30, 2023	Year Ended December 31, 2022
Average realized prices:		
Oil (per Bbl)	$ 75.46	$ 93.43
Natural Gas (per Mcf)	$ 2.56	$ 6.34
NGL (per Bbl)	$ 25.29	$ 39.27
Total (Boe)	$ 36.10	$ 55.37
Total (Boe) (after effects of derivative settlements)	$ 36.97	$ 49.53

Derivative arrangements

To mitigate the risk associated with volatile commodity prices and to further enhance the stability of our cash flow available for distribution, from time to time, we may opportunistically hedge a portion of our production volumes at prices we deem attractive. All derivative instruments are recorded on the consolidated balance sheets included elsewhere in this prospectus as an asset or liability measured at fair value, with changes in the fair value of the derivatives recorded currently in the consolidated statements of operations. For the years ended December 31, 2022 and 2021 and for the six months ended June 30, 2023 and 2022, we elected not to designate any of our derivative contracts as cash flow hedges.

Our hedging instruments provide only partial price protection against declines in prices and may partially limit our potential gains from future price increases. In addition, in times of low commodity prices, our ability to enter into additional commodity derivative contracts with favorable commodity price terms may be limited, which may adversely impact our future operating income and cash flows as compared to historical periods during which we were able to hedge a portion of our production at higher prices. See "— Quantitative and Qualitative Disclosure About Market Risk" below for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

Product sales

Product sales are generated from the Company's sale of natural gas, oil and NGL production purchased from third parties and subsequently gathered and processed through the Company's owned midstream facilities. Product sales includes activity from certain third-party percent-of-proceeds contracts where the Company keeps a contractually based percentage of proceeds from the sale of natural gas and NGL production, as payment for processing natural gas from the third parties. The costs of buying natural gas, oil and NGL production from third party shippers are included as costs of product sales on the statement of operations.

Midstream revenues and expenses

We believe a key competitive advantage that we have over other operators is that we own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure. The revenue generated by our midstream assets enhances the value of our properties and can eliminate third-party costs and inefficiencies for our production. In addition, our owned midstream systems generate third-party revenue, which effectively reduces the cost of operating our midstream assets and reduces our average breakeven costs compared to other operators. Revenues associated with hydrocarbon and water volumes that flow through our midstream infrastructure for third-parties (including volumes associated with third-party non-operating working interests in our wells) are reflected within our financial statements in midstream revenue, and the operating expenses of our midstream infrastructure associated with these volumes are reflected in our financial statements as midstream operating expense. The economic effect of natural gas and water volumes associated with our working interest in our operating wells that flow through our midstream infrastructure is not reflected in our midstream revenue or midstream operating expense. Instead, the economic effect for natural gas volumes is netted out and reflected in our gathering and processing costs while the economic effect of water volumes are netted out and reflected in our lease operating expense.

Principal Components of our Cost Structure

The sections below summarize the primary operating costs we typically incur. Some of these costs vary with commodity prices, some trend with the type and volume of production, and others are a function of the number of wells we own.

Gathering and processing expense. Gathering and processing expense primarily includes costs to transport our production to the various points of sale and tends to vary with production volumes. We own substantial gathering and processing assets, which improves our cost structure and enhances the stability of our hydrocarbon flows. The economic effect of natural gas volumes associated with our working interest in our operating wells that flow through our midstream infrastructure is not reflected in our midstream revenue or midstream operating expense, but instead are netted out and reflected in our gathering and processing costs. The amount of these expenses is the portion of the operating cost of our midstream assets allocated to our produced volumes on a proportional basis. As a result, our midstream assets result in attractive rates for gathering and processing our production, which results in reduced gathering and processing expense.

Lease operating expense. LOE includes the costs incurred in the operation of producing properties, ad valorem taxes and workover costs. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. Certain of our LOE components are variable and increase or decrease as our production and water volumes increase or decrease. The economic effect of water volumes associated with our working interest in our operating wells that flow through our midstream infrastructure is not reflected in our midstream revenue or midstream operating expense, but instead are netted out and reflected in our lease operating expense. The amount of these expenses is the portion of the operating cost of our midstream assets allocated to our produced volumes on a proportional basis. As a result, our midstream assets result in attractive rates for water handling and saltwater disposal, which results in reduced lease operating expense.

We constantly monitor and evaluate our LOE to ensure we are maximizing profitability. Analyzing trends and costs within our various development areas allows us to optimize for current and future development. Although we strive to reduce LOE, these expenses can increase or decrease on a per Boe basis as a result of various factors that arise as we operate our properties or make acquisitions and dispositions of properties. For example, we may increase field-level expenditures to optimize our operations, incurring higher expenses in one quarter relative to another, or we may acquire or dispose of properties that have differing LOE per Boe. These activities would influence our overall operating cost and could cause fluctuations when comparing LOE on a period-to-period basis.

Our LOE includes the costs of the legacy vertical wells associated with certain of our acquisitions. We have historically seen our per Boe costs decrease as a result of increased efficiencies after taking over operations.

Production taxes. We pay taxes on a portion of our production based on a percentage of revenue at rates established by state taxing authorities. We attempt to take full advantage of all credits and exemptions in our taxing jurisdictions.

Depreciation, depletion, amortization and accretion expense. Depreciation, depletion, amortization and accretion expense is the systematic expensing of the capitalized costs incurred to acquire and develop oil and gas producing properties. We use the full cost method of accounting for our oil and gas producing activities. See "— Critical Accounting Policies and Estimates" included below, for a discussion of this accounting method and unit-of-production depreciation and amortization.

General and administrative expense. General and administrative expense primarily reflects payroll and benefits, including equity-based compensation, for our corporate staff and management of our production and development operations, costs of maintaining our headquarters, information technology expenses, and legal and other fees for professional services, including audit and acquisition-related expenses. In connection with the consummation of this offering, we expect to incur additional costs related to being a publicly-traded partnership. 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."

Gain (Loss) on Derivative Instruments: We are required to recognize our derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. We have not designated our derivative instruments as hedges for accounting purposes and, as a result, mark our derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments for each period in the statements of operations.

Interest Expense: We finance a portion of our working capital requirements and capital expenditures with borrowings under our Existing Credit Facilities. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders under our Existing Credit Facilities in interest expense.

Non-GAAP Financial Measures

Adjusted EBITDA

We include in this prospectus the supplemental non-GAAP financial performance measure Adjusted EBITDA and provide our calculation of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income, our most directly comparable financial measures calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income before (1) interest expense, (2) depreciation, depletion and amortization, (3) unrealized (gain) loss on derivative settlements, (4) equity-based compensation expense, (5) loss on contingent consideration and (6) (gain) loss on sale of assets.

Adjusted EBITDA is used as a supplemental financial performance measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to more effectively evaluate our operating performance and our results of operation from period to period and against our peers without regard to financing methods, capital structure or historical cost basis. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA is not a measurement of our financial performance under GAAP and should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as indicators of our operating performance. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax burden, as well as the historic costs of depreciable assets, none of which are reflected in Adjusted EBITDA. Our presentation of Adjusted EBITDA should not be construed as an inference that our results will be unaffected by unusual items. Our computations of Adjusted EBITDA may not be identical to other similarly titled measures of other companies.

Cash Available for Distribution

Cash available for distribution is not a measure of net income or net cash flow provided by or used in operating activities as determined by GAAP. Cash available for distribution is a supplemental non-GAAP financial performance measure used by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, 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 net income less (1) interest expense, (2) depreciation, depletion and amortization, (3) unrealized (gain) loss on derivative settlements, (4) equity-based compensation expense, (5) loss on contingent consideration, (6) (gain) loss on sale of assets, (7) settlement of asset retirement obligations, (8) net cash interest expense, (9) development costs, (10) settlement of contingent consideration and (11) change in accrued realized derivative settlements. Development costs include all of our capital expenditures, other than acquisitions. Cash available for distribution will not reflect changes in working capital balances. Cash available for distribution is not a measurement of our financial performance or liquidity under GAAP and should not be considered as an alternative to, or more meaningful than, net income or net cash provided by or used in operating activities as determined in accordance with GAAP or as indicators of our financial performance and liquidity. The GAAP measures most directly comparable to cash available for distribution are net income and net cash provided by operating activities. Cash available for distribution should not be considered as an alternative to, or more meaningful than, net income or net cash provided by operating activities.

Factors Affecting the Comparability of Our Future Results of Operations to Our Historical Results of Operations

Our future results of operations may not be comparable to our historical results of operations for the periods presented, primarily for the reasons described below.

Acquisitions

We have completed eight acquisitions since 2021. These acquisitions are reflected in our results of operations as of and after the date of completion for each such acquisition. As a result, periods prior to each such acquisition will not contain the results of such acquired assets which will affect the comparability of our results of operations for certain historical periods. We may continue to grow our operations through acquisitions when economical, including by funding such acquisitions under our New Credit Facility.

Reorganization Transactions

The historical consolidated financial statements included in this prospectus are of our predecessor, BCE-Mach and BCE-Mach II prior to the Reorganization Transactions described in “Prospectus Summary — Reorganization Transactions, Partnership Structure and New Credit Facility.” Our historical financial data may not yield an accurate indication of what our actual results would have been if the Reorganization Transactions had been completed at the beginning of the periods presented or of what our future results of operations are likely to be. For our results of operation of our predecessor, BCE-Mach and BCE-Mach II presented on a combined basis and pro forma for the Reorganization Transactions and this offering, please see “Selected Historical and Pro Forma Financial and Operating Data” presented elsewhere in this prospectus.

Public company expenses

Upon the completion of this offering, we expect to incur incremental non-recurring costs related to our transition to a publicly traded partnership, including the costs of this initial public offering and the costs associated with the initial implementation of our internal control 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 and Schedule K-1 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 expenses are not included in our historical or pro forma financial statements; however, we expect those expenses to be approximately $ per year.

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.

Results of Operations

Six Months Ended June 30, 2023 Compared to the Six Months Ended June 30, 2022

Predecessor

Revenue

The following table provides the components of our predecessor's revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

	Predecessor			
	Six Months Ended June 30,		Change	
($ in thousands)	**2023**	**2022**	**Amount**	**Percent**
Revenues:				
Oil	$ 208,315	$ 219,126	$ (10,812)	(5)%
Natural gas	69,580	129,893	(60,313)	(46)%
Natural gas liquids	34,718	59,423	(24,704)	(42)%
Total oil, natural gas, and NGL sales	312,613	408,442	(95,829)	(23)%
Gain (loss) on oil and natural gas derivatives, net	15,742	(72,857)	88,599	122%
Midstream revenue	13,318	19,883	(6,565)	(33)%
Product sales	17,421	47,960	(30,539)	(64)%
Total revenues	$ 359,094	$ 403,428	$ (44,334)	(11)%
Average Sales Price[1]:				
Oil ($/Bbl)	$ 75.46	$ 102.35	$ (26.89)	(26)%
Natural gas ($/Mcf)	$ 2.56	$ 6.32	$ (3.76)	(59)%
NGL ($/Bbl)	$ 25.29	$ 44.95	$ (19.66)	(44)%
Total ($/Boe) – before effects of realized derivatives	$ 36.10	$ 59.27	$ (23.17)	(39)%
Total ($/Boe) – after effects of realized derivatives	$ 36.97	$ 51.12	$ (14.15)	(28)%
Net Production Volumes:				
Oil (MBbl)	2,760	2,141	619	29%
Natural gas (MMcf)	27,157	20,569	6,588	32%
NGL (MBbl)	1,373	1,322	51	4%
Total (MBoe)	8,660	6,891	1,769	26%
Average daily total volumes (MBoe/d)	47.84	38.07	9.77	26%

(1) Average sales prices reflected above exclude gathering and processing expense and the separate benefit of third party midstream revenues.

Revenue and other operating income

Oil, natural gas and NGL sales. Revenues from oil, natural gas and NGL sales decreased $95.8million, or 23% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was primarily a result of a 26% decrease in the average selling price on oil resulting in a decrease in oil sales revenue of $57.6 million, a 59% decrease in the average selling price on natural gas resulting in a decrease in natural gas sales revenue of $77.2 million, and a 44% decrease on the average selling price on NGLs resulting in a decrease in NGL sales revenue of $26.0 million. An increase in production of 1,769 MBoe for the six-month period ended June 30, 2023, compared to the six-month period ended June 30, 2022, resulted in an increase in oil, natural gas and NGL revenues of $64.9 million.

Oil and Natural Gas Derivatives. For the six-month period ended June 30, 2023, our predecessor had realized gains on derivative instruments of $7.5 million and unrealized gains of $8.2 million for total gains of $15.7 million. For the six-month period ended June 30, 2022, our predecessor had realized losses on derivative instruments of $56.1 million and unrealized losses of $16.7 million for total losses of $72.9 million. The increase in realized gains is primarily from the overall decrease in oil and gas prices in 2023.

Production. Production increased 1,769 MBoe, or 26% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase was primarily attributable to an increase in new production from wells that were brought on-line as a result of increased drilling activity subsequent to June 30, 2022.

Product sales. Product sales decreased $30.5 million, or 64% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was primarily a result of decreases in non-operated production resulting in less product sales of $22.0million. The decrease in the average selling price on natural gas and NGLs resulted in a decrease of $7.9 million and $5.0 million, respectively. These decreases were partially offset with the acquisition of midstream gathering and plant facilities in June 2022 contributed to an increase of $3.7 million in product sales.

Midstream revenue. Midstream revenue decreased $6.6 million, or 33% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, primarily due to lower non-operated volumes running through the Company’s midstream facilities. Of the total decrease, $3.4 million relates to decreases in fee revenue related to gathering and processing, and $3.2 million is due to decreased saltwater gathering and disposal revenue.

Operating expenses

The following table summarizes our predecessor’s expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	Predecessor			
	Six Months Ended June 30,		Change	
($ in thousands)	2023	2022	Amount	Percent
Operating Expenses:				
Gathering and processing expense	$ 17,510	$ 20,812	$ (3,302)	(16)%
Lease operating expense	$ 60,615	$ 39,592	$ 21,023	53%
Midstream operating expense	$ 5,538	$ 6,976	$ (1,438)	(21)%
Cost of product sales	$ 15,575	$ 44,958	$ (29,383)	(65)%
Production taxes	$ 15,526	$ 22,675	$ (7,149)	(32)%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 58,095	$ 29,374	$ 28,721	98%
Depreciation and amortization expense – other	$ 2,793	$ 2,008	$ 785	39%
General and administrative	$ 9,905	$ 13,648	$ (3,743)	(27)%
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 2.02	$ 3.02	$ (1.00)	(33)%
Lease operating expense	$ 7.00	$ 5.75	$ 1.25	22%
Production taxes (% of oil, natural gas and NGL sales)	$ 5.0%	5.6%	(0.6)%	(11)%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 6.71	$ 4.26	$ 2.45	57%
Depreciation and amortization expense – other	$ 0.32	$ 0.29	$ 0.03	11%
General and administrative	$ 1.14	$ 1.98	$ (0.84)	(42)%

Gathering and processing expense. Gathering and processing expense decreased by $3.3 million, or 16% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, primarily due to decreased natural gas prices leading to lower fuel costs. Gathering and processing expense per Boe produced decreased by $1.00 due to lower fuel expense that fluctuated with the decrease in commodity gas prices.

Lease operating expense. Lease operating expense increased $21.0 million, or 53% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. Of the total increases, wells brought on-line as a result of the increased drilling activity subsequent to 2023 caused an increase of $13.6 million. Approximately $6.6 million was attributable to acquisitions that closed in first two quarters of 2022. Lease operating expenses per Boe increased $1.25 due to the reasons noted above.

Midstream operating expense. Midstream operating expense decreased $1.4 million, or 21% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, primarily due to a decrease in plant operating expense of $0.9 million and a decrease in water disposal costs of $0.8 million.

Cost of product sales. Cost of product sales decreased $29.4 million, or 65% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was primarily a result of decreases in non-operated production resulting in additional cost of product sales of $21.1million. The increase in the average purchase price on natural gas and NGLs resulted in an increase of $7.6 million and $4.8 million, respectively. This was partially offset with the acquisition of midstream gathering and plant facilities in June 2022 which contributed to an increase of $3.6 million.

Production taxes. Production taxes decreased $7.1 million, or 32% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was primarily a result of a decrease in the average selling price on all products, resulting in a decrease of $12.0 million, partially offset by an increase in production, resulting in an increase of $4.8 million. Production taxes as a percentage of revenue decreased from 5.6% for the six-month period ended June 30, 2022, to 5.0% for the six-month period ended June 30, 2023.

Depreciation, depletion, amortization and accretion expense. Depreciation, depletion, amortization and accretion expense for oil and natural gas properties increased by $28.7 million, or 98% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase is primarily attributable to additional drilling activities and acquisitions in 2022 that added to the depletable base and increased overall production. Depreciation, depletion, amortization and accretion expense for other assets increased $0.8 million, or 39% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, primarily due to additional assets acquired during the year.

General and administrative costs. General and administrative costs decreased $3.7 million, or 27% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in general and administrative costs was primarily due to a $2.5 million reduction in equity compensation expense recorded in the six-month period ended June 30, 2023, in comparison to the six-month period ended June 30, 2022.

BCE-Mach

Revenue

The following table provides the components of BCE-Mach's revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

	BCE-Mach			
	Six Months Ended June 30,		Change	
($ in thousands)	2023	2022	Amount	Percent
Revenues:				
Oil	$ 38,873	$ 52,878	$ (14,005)	(26)%
Natural gas	20,033	46,467	(26,434)	(57)%
Natural gas liquids	11,804	22,019	(10,215)	(46)%
Total oil, natural gas, and NGL sales	70,710	121,364	(50,654)	(42)%
Gain (Loss) gain on oil and natural gas derivatives, net	6,048	(42,710)	48,758	114%
Total revenues	$ 76,758	$ 78,654	$ (1,896)	(2)%
Average Sales Price:				
Oil ($/Bbl)	$ 72.68	$ 101.09	$ (28.41)	(28)%
Natural gas ($/Mcf)	$ 2.51	$ 5.75	$ (3.24)	(56)%
NGL ($/Bbl)	$ 25.43	$ 43.88	$ (18.45)	(42)%
Total ($/Boe)–before effects of realized derivatives	$ 30.32	$ 51.15	$ (20.83)	(41)%
Total ($/Boe)–after effects of realized derivatives	$ 28.32	$ 35.83	$ (7.51)	(21)%
Net Production Volumes:				
Oil (MBbl)	535	523	12	2%
Natural gas (MMcf)	7,997	8,088	(91)	(1)%
NGL (MBbl)	464	502	(38)	(8)%
Total (MBoe)	2,332	2,373	(41)	(2)%
Average daily total volumes (MBoe/d)	12.88	13.11	(0.23)	(2)%

Revenue and other operating income

Oil, natural gas and NGL sales. Revenues from oil, natural gas and NGL sales decreased $50.7million, or 42% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was primarily a result of a decrease in the average selling price on oil of 28% resulting in a decrease in oil revenue of $14.9 million, on natural gas of 56% resulting in a decrease in gas revenue of $26.2 million, and on NGLs of 42% resulting in a decrease in NGL sales revenue of $9.3million.

Production. Production decreased 41 MBoe for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, due to natural production declines in our existing producing wells, which was partially offset by production from newly drilled wells.

Oil and Natural Gas Derivatives. For the six-month period ended June 30, 2023, BCE-Mach had realized losses on derivative instruments of $4.7 million and unrealized gains of $10.7 million for total gains of $6.0 million. For the six-month period ended June 30, 2022, BCE-Mach had realized losses on derivative instruments of $36.3 million and unrealized losses of $6.4 million for total losses of $42.7 million. The decrease in realized losses is primarily from the overall decrease in oil and gas prices in 2023.

Operating expenses

The following table summarizes BCE-Mach's expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	BCE-Mach			
	Six Months Ended June 30,		Change	
($ in thousands)	2023	2022	Amount	Percent
Operating Expenses:				
Gathering and processing expense	$ 13,928	$ 16,746	$ (2,818)	(17)%
Lease operating expense	$ 20,514	$ 16,565	$ 3,949	24%
Production taxes	$ 3,644	$ 6,875	$ (3,231)	(47)%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 12,678	$ 12,822	$ (144)	(1)%
Depreciation and amortization expense – other	$ 4,454	$ 4,094	$ 360	9%
General and administrative	$ 4,791	$ 2,667	$ 2,124	80%
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 5.97	$ 7.06	$ (1.09)	(15)%
Lease operating expense	$ 8.80	$ 6.98	$ 1.82	26%
Production taxes (% of oil, natural gas and NGL sales)	$ 5.2%	5.7%	(0.5)%	(9)%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 5.44	$ 5.40	$ 0.04	1%
Depreciation and amortization expense – other	$ 1.91	$ 1.73	$ 0.18	11%
General and administrative	$ 2.05	$ 1.12	$ 0.93	83%

Gathering and processing expense. Gathering and processing expense decreased by $2.8 million, or 17% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, primarily due to decreased natural gas prices leading to lower fuel costs. Gathering and processing expense per Boe produced decreased by $1.09 primarily lower fuel expense that fluctuated with the decrease in commodity gas prices, as well as the decrease in production volume.

Lease operating expense. Lease operating expense increased $3.9 million, or 24% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase in lease operating expense was primarily due to an increase of $2.7 million in workovers, repairs and maintenance, an increase of $0.6 million in compression costs, and an increase of $0.6 million in compensation related expense for field employees. Lease operating expenses per Boe produced increased $1.82 primarily due to the reasons noted above, as well as the decrease in production.

Production taxes. Production taxes decreased $3.2 million, or 47% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was a result of a decrease in the average selling price on all products. Production taxes as a percentage of revenue decreased from 5.7% for the six-month period ended June 30, 2022, to 5.2% for the six-month period ended June 30, 2023.

Depreciation, depletion, amortization and accretion expense. Depreciation, depletion, amortization and accretion expense for oil and natural gas properties decreased by $0.1 million, or 1% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. Depreciation, depletion, and amortization and for other assets increased $0.4 million, or 9% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, primarily due to additional assets acquired during the year.

General and administrative costs. General and administrative costs increased $2.1 million, or 80% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase in general and administrative costs was primarily due to a $2.0 million increase in compensation and benefits in the six-month period ended June 30, 2023.

BCE-Mach II

Revenue

The following table provides the components of BCE-Mach II's revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

	BCE-Mach II			
	Six Months Ended June 30,		Change	
($ in thousands)	2023	2022	Amount	Percent
Revenues:				
Oil	$ 5,349	$ 7,630	$ (2,282)	(30)%
Natural gas	6,970	18,194	(11,224)	(62)%
Natural gas liquids	4,044	9,054	(5,010)	(55)%
Total oil, natural gas, and NGL sales	16,363	34,878	(18,515)	(53)%
Gain (loss) on oil and natural gas derivatives, net	828	(1,679)	2,507	149%
Midstream revenue	213	245	(32)	(13)%
Total revenues	$ 17,404	$ 33,444	$ (16,040)	(48)%
Average Sales Price[1]:				
Oil ($/Bbl)	$ 71.38	$ 99.77	$ (28.39)	(28)%
Natural gas ($/Mcf)	$ 1.98	$ 4.90	$ (2.92)	(60)%
NGL ($/Bbl)	$ 19.40	$ 38.73	$ (19.33)	(50)%
Total ($/Boe) – before effects of realized derivatives	$ 18.80	$ 37.56	$ (18.76)	(50)%
Total ($/Boe) – after effects of realized derivatives	$ 20.11	$ 35.77	$ (15.66)	(44)%
Net Production Volumes:				
Oil (MBbl)	75	76	(1)	(2)%
Natural gas (MMcf)	3,521	3,711	(190)	(5)%
NGL (MBbl)	208	234	(26)	(11)%
Total (MBoe)	870	929	(59)	(6)%
Average daily total volumes (MBoe/d)	4.81	5.13	(0.32)	(6)%

(1) Average sales prices reflected above exclude gathering and processing expense and the separate benefit of third party midstream revenues.

Revenue and other operating income

Oil, natural gas and NGL sales. Revenues from oil, natural gas and NGL sales decreased $18.5 million, or 53% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was primarily a result of a decrease in the average selling price on oil of 28% resulting in a decrease in oil revenue of $2.2 million, on natural gas of 60% resulting in a decrease in gas revenue of $10.9 million, and on NGLs of 50% resulting in a decrease in NGL sales revenue of $4.5 million. The decrease in production from the natural decline on our producing wells resulted in a decrease in oil, natural gas and NGL revenues of $1.0 million.

Production. Production decreased 59 MBoe, or 6% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease was primarily attributable to a decrease in production from natural production declines in our existing producing wells.

Oil and Natural Gas Derivatives. For the six-month period ended June 30, 2023, BCE-Mach II had realized gains on derivative instruments of $1.1 million and unrealized losses of $0.3 million for total gains of $0.8 million. For the six-month period ended June 30, 2022, BCE-Mach II had realized losses on derivative instruments of $1.6 million and unrealized losses of $33 thousand for total losses of $1.7 million. The increase in realized gains is primarily from the overall decrease in oil and gas prices in 2023.

Midstream revenue. Midstream revenue decreased $32 thousand, or 13% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in midstream revenue can be attributed to a decrease production on wells that flow into the gathering system.

Operating expenses

The following table summarizes BCE-Mach II's expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	BCE-Mach II			
	Six Months Ended June 30,		Change	
($ in thousands)	2023	2022	Amount	Percent
Operating Expenses:				
Gathering and processing expense	$ 1,992	$ 2,770	$ (778)	(28)%
Lease operating expense	$ 6,310	$ 6,155	$ 155	3%
Midstream operating expense	$ 223	$ 217	$ 6	3%
Production taxes	$ 833	$ 1,966	$ (1,133)	(58)%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 2,167	$ 2,211	$ (44)	(2)%
Depreciation and amortization expense – other	$ 346	$ 341	$ 5	1%
General and administrative	$ (1,536)	$ (1,349)	$ (187)	(14)%
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 2.29	$ 2.98	$ (0.69)	(23)%
Lease operating expense	$ 7.25	$ 6.63	$ 0.62	9%
Production taxes (% of oil, natural gas and NGL sales)	$ 5.1%	5.6%	(0.5)%	(10)%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 2.49	$ 2.38	$ 0.11	5%
Depreciation and amortization expense – other	$ 0.40	$ 0.37	$ 0.03	8%
General and administrative	$ (1.77)	$ (1.45)	$ (0.32)	22%

Gathering and processing expense. Gathering and processing expense decreased by $0.8 million, or 28% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022, primarily due to decreased natural gas prices leading to lower fuel costs as well as a decrease in production. Gathering and processing expense per Boe produced decreased by $0.69 primarily due to lower fuel expense that fluctuated with the decrease in commodity gas prices.

Lease operating expense. Lease operating expense increased $0.2 million, or 3% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. Lease operating expense per Boe produced increased $0.62 due to decreases in production stemming from natural well declines.

Midstream operating expense. Midstream operating expense increased by $6 thousand, or 3% for the six months ended June 30, 2023, as compared to the six months ended June30, 2022.

Production taxes. Production taxes decreased $1.1 million, or 58% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. This decrease was primarily a result of a decrease in the average selling price on all products. Production taxes as a percentage of revenue decreased from 5.6% for the six-month period ended June 30, 2022, to 5.1% for the six-month period ended June 30, 2023.

Depreciation, depletion, amortization and accretion expense. Depreciation, depletion, amortization and accretion expense for oil and natural gas properties decreased by $44 thousand, or 2% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. Depreciation and amortization expense for other assets increased $5 thousand, or 1% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022.

General and administrative costs. General and administrative costs decreased $0.2 million, or 14% for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in general and administrative costs was primarily due to a $0.2 million reduction in equity compensation expense recorded in the six-month period ended June 30, 2023. General and administrative expense includes cost recoveries from joint interest owners using contractual rates established by our joint operating agreements. Costs recovered for both the six-month period ended June 30, 2023, and 2022 was $3.3 million.

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

Predecessor

Revenue

The following table provides the components of our predecessor's revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

	Predecessor			
	Year Ended December 31,		Change	
($ in thousands)	2022	2021	Amount	Percent
Revenues:				
Oil	$ 448,567	$ 189,827	$ 258,740	136%
Natural gas	301,423	131,819	169,604	129%
Natural gas liquids	110,398	75,854	34,544	46%
Total oil, natural gas, and NGL sales	860,388	397,500	462,888	116%
(Loss) gain on oil and natural gas derivatives, net	(67,453)	(67,549)	96	0%
Midstream revenue	44,373	31,883	12,490	39%
Product sales	100,106	30,663	69,443	226%
Total revenues	$ 937,414	$ 392,497	$ 544,917	139%
Average Sales Price[1]:				
Oil ($/Bbl)	$ 93.43	$ 68.35	$ 25.08	37%
Natural gas ($/Mcf)	$ 6.34	$ 4.08	$ 2.26	55%
NGL ($/Bbl)	$ 39.27	$ 34.80	$ 4.47	13%
Total ($/Boe) – before effects of realized derivatives	$ 55.37	$ 38.43	$ 16.93	44%
Total ($/Boe) – after effects of realized derivatives	$ 49.53	$ 32.51	$ 17.02	52%
Net Production Volumes:				
Oil (MBbl)	4,801	2,777	2,024	73%
Natural gas (MMcf)	47,561	32,313	15,249	47%
NGL (MBbl)	2,812	2,180	632	29%
Total (MBoe)	15,539	10,343	5,197	50%
Average daily total volumes (MBoe/d)	42.57	28.34	14.24	50%

(1) Average sales prices reflected above exclude gathering and processing expense and the separate benefit of third party midstream revenues.

Revenue and other operating income

Oil, natural gas and NGL sales. Revenues from oil, natural gas and NGL sales increased $462.9 million, or 116% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of an increase in production from additional drilling activities, as well as new wells acquired during the year, resulting in an increase in oil, natural gas and NGL revenues of $310.5 million. Incrementally, a 37% increase in the average selling price on oil resulted in an increase in oil production revenue of $69.7 million, a

55% increase in the average selling price on natural gas resulted in an increase in natural gas production revenue of $73.0 million, and a 13% increase on the average selling price on NGLs resulted in an increase in NGL production revenue of $9.7 million.

Oil and Natural Gas Derivatives. For the year ended December 31, 2022, our predecessor had realized losses on derivative instruments of $90.8 million and an unrealized gain of $23.3 million for total losses of $67.5 million. For the year ended December 31, 2021, our predecessor had realized losses on derivative instruments of $61.3 million and an unrealized loss of $6.3 million for total losses of $67.5 million. The increase in realized losses is primarily from the overall increase in oil and gas prices in 2022.

Production. Production increased 5,197 MBoe, or 50% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase was primarily attributable to an increase in production of 1,672 MBoe as a result of additional production from acquisitions that closed in 2022 and 3,525 MBoe of new production from wells that were brought on-line as a result of increased drilling activity throughout 2022.

Product sales. Product sales increased $69.4 million, or 226% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of increases in production resulting in additional product sales of $51.2 million. Additionally, the acquisition of midstream gathering and plant facilities in 2021 and 2022 contributed to an increase of $10.8 million. The increase in the average selling price on natural gas and NGLs resulted in an increase of $3.2 million and $0.8 million, respectively.

Midstream revenue. Midstream revenue increased $12.5 million, or 39% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to increased drilling activity resulting in increased throughput in our gathering and processing assets. Of the total increase, $7.2 million relates to increases in fee revenue related to gathering and processing, and $5.3 million is due to increased saltwater gathering and disposal revenue.

Operating expenses

The following table summarizes our predecessor's expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	Predecessor			
	Year Ended December 31,		Change	
($ in thousands)	2022	2021	Amount	Percent
Operating Expenses:				
Gathering and processing expense	$ 47,484	$ 27,987	$ 19,497	70%
Lease operating expense	$ 95,941	$ 45,391	$ 50,550	111%
Midstream operating expense	$ 15,157	$ 12,248	$ 2,909	24%
Cost of product sales	$ 94,580	$ 28,687	$ 65,893	230%
Production taxes	$ 47,825	$ 21,165	$ 26,660	126%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 84,070	$ 37,537	$ 46,533	124%
Depreciation and amortization expense – other	$ 4,519	$ 3,148	$ 1,371	44%
General and administrative	$ 25,454	$ 60,927	$ (35,473)	(58)%
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 3.06	$ 2.71	$ 0.35	13%
Lease operating expense	$ 6.17	$ 4.39	$ 1.79	41%
Production taxes (% of oil, natural gas and NGL sales)	5.6%	5.3%	0.2%	4%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 5.41	$ 3.63	$ 1.78	49%
Depreciation and amortization expense – other	$ 0.29	$ 0.30	$ (0.01)	(4)%
General and administrative	$ 1.64	$ 5.89	$ (4.25)	(72)%

Gathering and processing expense. Gathering and processing expense increased by $19.5 million, or 70% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to increased natural gas prices leading to higher fuel costs as well as an increase in production. Gathering and processing expense per Boe produced increased by $0.35 due to higher fuel expense that fluctuated with the increase in commodity gas prices.

Lease operating expense. Lease operating expense increased $50.6 million, or 111% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. Of the total increases, approximately $28.0 million was attributable to acquisitions that closed in the last half of 2021 and first two quarters of 2022. The wells brought on-line as a result of the increased drilling activity throughout 2022 caused an increase of $14.9 million. Additionally, our predecessor had increases with respect to its non-operated lease operating expense of $4.3 million, general equipment repairs of $2.5 million, and compression rentals of $1.8 million. Overall increases were also partially attributable to the inflationary environment throughout 2022. Lease operating expenses per Boe increased $1.79 due to the reasons noted above.

Midstream operating expense. Midstream operating expense increased $2.9 million, or 24% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to an increase in water disposal costs of $2.6 million stemming from increases in utility costs of $1.0 million and contract labor of $0.9 million.

Cost of product sales. Cost of product sales increased $65.9 million, or 230% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of increases in production resulting in additional cost of product sales of $48.6 million. Additionally, the acquisition of midstream gathering and plant facilities in 2021 and 2022 contributed to an increase of $10.3 million. The increase in the average purchase price on natural gas and NGLs resulted in an increase of $3.0 million and $0.8 million, respectively.

Production taxes. Production taxes increased $26.7 million, or 126% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of an increase in the average selling price on all products, resulting in an increases of $8.8 million, and an increase in production, resulting in an increase of $17.9 million. Production taxes as a percentage of revenue increased from 5.3% for the year ended December 31, 2021 to 5.6% for the year ended December 31, 2022.

Depreciation, depletion, amortization and accretion expense. Depreciation, depletion, amortization and accretion expense for oil and natural gas properties increased by $46.5 million, or 124% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase is primarily attributable to additional drilling activities and acquisitions in 2022 that added to the depletable base. Depreciation, depletion, amortization and accretion expense for other assets increased $1.4 million, or 44% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to additional assets acquired during the year.

General and administrative costs. General and administrative costs decreased $35.5 million, or 58% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The decrease in general and administrative costs was primarily due to a $37.8 million reduction in equity compensation expense recorded in the year ended December 31, 2022.

BCE-Mach

Revenue

The following table provides the components of BCE-Mach's revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

	BCE-Mach			
	Year Ended December 31,		Change	
($ in thousands)	2022	2021	Amount	Percent
Revenues:				
Oil	$ 96,734	$ 86,404	$ 10,330	12%
Natural gas	98,469	61,164	37,306	61%
Natural gas liquids	38,441	35,497	2,944	8%
Total oil, natural gas, and NGL sales	233,644	183,065	50,579	28%
Gain (Loss) gain on oil and natural gas derivatives, net	(42,334)	(59,959)	17,625	(29)%
Total revenues	$ 191,310	$ 123,106	$ 68,204	55%
Average Sales Price:				
Oil ($/Bbl)	$ 94.54	$ 66.52	$ 28.02	42%
Natural gas ($/Mcf)	$ 6.24	$ 3.40	$ 2.84	83%
NGL ($/Bbl)	$ 39.65	$ 31.40	$ 8.25	26%
Total ($/Boe) – before effects of realized derivatives	$ 50.55	$ 33.75	$ 16.80	50%
Total ($/Boe) – after effects of realized derivatives	$ 35.28	$ 27.79	$ 7.49	27%
Net Production Volumes:				
Oil (MBbl)	1,023	1,299	(276)	(21)%
Natural gas (MMcf)	15,776	17,967	(2,191)	(12)%
NGL (MBbl)	969	1,131	(161)	(14)%
Total (MBoe)	4,622	5,424	(802)	(15)%
Average daily total volumes (MBoe/d)	12.66	14.86	(2.20)	(15)%

Revenue and other operating income

Oil, natural gas and NGL sales. Revenues from oil, natural gas and NGL sales increased $50.6 million, or 28% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of an increase in the average selling price on oil of 42% resulting in an increase in production revenue of $36.4 million, on natural gas of 83% resulting in an increase in production revenue of $51.0 million, and on NGLs of 26% resulting in an increase in oil, natural gas and NGL sales revenue of $9.3 million. The increases in revenue from increases in the average selling price were partially offset by a decrease in revenue from lower production of $46.1 million.

Production. Production decreased 802 MBoe, or 15% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The decline in production is primarily attributable to natural production declines in our existing producing wells.

Oil and Natural Gas Derivatives. For the year ended December 31, 2022, BCE-Mach had realized losses on derivative instruments of $70.6 million and an unrealized gain of $28.3 million for total losses of $42.3 million. For the year ended December 31, 2021, BCE-Mach had realized losses on derivative instruments of $32.3 million and an unrealized loss of $27.6 million for total losses of $60.0 million. The increase in realized losses is primarily from the overall increase in oil and gas prices in 2022.

Operating expenses

The following table summarizes BCE-Mach's expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	BCE-Mach			
	Year Ended December 31,		Change	
($ in thousands)	2022	2021	Amount	Percent
Operating Expenses:				
Gathering and processing expense	$ 34,437	$ 30,729	$ 3,708	12%
Lease operating expense	$ 35,605	$ 24,578	$ 11,027	45%
Production taxes	$ 13,246	$ 9,645	$ 3,601	37%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 26,621	$ 26,977	$ (356)	(1)%
Depreciation and amortization expense – other	$ 8,318	$ 7,778	$ 540	7%
General and administrative	$ 4,577	$ 10,429	$ (5,852)	(56)%
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 7.45	$ 5.67	$ 1.79	32%
Lease operating expense	$ 7.70	$ 4.53	$ 3.17	70%
Production taxes (% of oil, natural gas and NGL sales)	5.7%	5.3%	0.4%	8%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 5.76	$ 4.97	$ 0.79	16%
Depreciation and amortization expense – other	$ 1.80	$ 1.43	$ 0.37	26%
General and administrative	$ 0.99	$ 1.92	$ (0.93)	(48)%

Gathering and processing expense. Gathering and processing expense increased by $3.7 million, or 12% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to increased natural gas prices leading to higher fuel costs. Gathering and processing expense per Boe produced increased by $1.79 primarily due to a decline in production volumes, coupled with higher fuel expense that fluctuated with the increase in commodity gas prices.

Lease operating expense. Lease operating expense increased $11.0 million, or 45% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in lease operating expense was primarily due to an increase of $4.9 million in workovers, repairs and maintenance, and an increase of $2.6 million in compression costs. Overall increases were also partially attributable to the inflationary environment throughout 2022. Lease operating expenses per Boe produced increased $3.17 primarily due to the reasons noted above, as well as the decrease in production.

Production taxes. Production taxes increased $3.6 million, or 37% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of an increase in the average selling price on all products, resulting in an increase of $6.9 million, partially offset with a decrease in production, resulting in a decrease of $3.3 million. Production taxes as a percentage of revenue increased from 5.3% for the year ended December 31, 2021 to 5.7% for the year ended December 31, 2022.

Depreciation, depletion, amortization and accretion expense. Depreciation, depletion, amortization and accretion expense for oil and natural gas properties decreased by $0.4 million, or 1% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The decrease was primarily attributable to a lower depreciable balance of properties because of previously recorded depreciation expense. Depreciation, depletion, amortization and accretion expense for other assets increased $0.5 million, or 7% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to additional assets acquired during the year.

General and administrative costs. General and administrative costs decreased $5.9 million, or 56% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The decrease in general and administrative costs was primarily due to a $3.5 million reduction in equity compensation expense recorded in the year ended December 31, 2022.

BCE-Mach II

Revenue

The following table provides the components of BCE-Mach II's revenue, net of transportation and marketing costs for the periods indicated, as well as each period's respective average realized prices and net production volumes. Some totals and changes throughout the below section may not sum or recalculate due to rounding.

	BCE-Mach II			
	Year Ended December 31,		Change	
($ in thousands)	2022	2021	Amount	Percent
Revenues:				
Oil	$ 14,580	$ 10,225	$ 4,355	43%
Natural gas	40,679	21,735	18,944	87%
Natural gas liquids	16,129	12,885	3,244	25%
Total oil, natural gas, and NGL sales	71,388	44,845	26,543	59%
(Loss) gain on oil and natural gas derivatives, net	(3,535)	(4,494)	959	(21)%
Midstream revenue	459	541	(82)	(15)%
Total revenues	$ 68,312	$ 40,892	$ 27,420	67%
Average Sales Price(1):				
Oil ($/Bbl)	$ 92.39	$ 63.78	$ 28.62	45%
Natural gas ($/Mcf)	$ 5.35	$ 3.12	$ 2.23	71%
NGL ($/Bbl)	$ 34.68	$ 26.80	$ 7.88	29%
Total ($/Boe) – before effects of realized derivatives	$ 37.75	$ 24.89	$ 12.86	52%
Total ($/Boe) – after effects of realized derivatives	$ 34.75	$ 23.27	$ 11.48	49%
Net Production Volumes:				
Oil (MBbl)	158	160	(3)	(2)%
Natural gas (MMcf)	7,610	6,965	645	9%
NGL (MBbl)	465	481	(16)	(3)%
Total (MBoe)	1,891	1,802	89	5%
Average daily total volumes (MBoe/d)	5.18	4.94	0.24	5%

(1) Average sales prices reflected above exclude gathering and processing expense and the separate benefit of third party midstream revenues.

Revenue and other operating income

Oil, natural gas and NGL sales. Revenues from oil, natural gas and NGL sales increased $26.5 million, or 59% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of an increase in the average selling price on oil of 45% resulting in an increase in production revenue of $4.6 million, on natural gas of 71% resulting in an increase in production revenue of $15.5 million, and on NGLs of 29% resulting in an increase in production revenue of $3.8 million. The increase in production from new wells acquired during the year, which was partially offset by decline on our existing wells, resulted in an increase in oil, natural gas and NGL revenues of $2.7 million.

Production. Production increased 89 MBoe, or 5% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase was primarily attributable to an increase in production of 195 MBoe as a result of additional production from acquisitions that closed during the first quarter of 2022, partially offset by 106 MBoe of natural production declines in our existing producing wells.

Oil and Natural Gas Derivatives. For the year ended December 31, 2022, BCE-Mach II had realized losses on derivative instruments of $5.8 million and an unrealized gain of $2.3 million for total losses of $3.5 million. For the year ended December 31, 2021, BCE-Mach II had realized losses on derivative instruments of $2.7 million and an unrealized loss of $1.8 million for total losses of $4.5 million. The increase in realized losses is primarily from the overall increase in oil and gas prices in 2022.

Midstream revenue. Midstream revenue decreased $0.1 million, or 15% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The decrease in midstream revenue can be attributed to a decrease production on wells that flow into the gathering system.

Operating expenses

The following table summarizes BCE-Mach II's expenses for the periods indicated and includes a presentation of certain expenses on a per Boe basis, as we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis:

	BCE-Mach II			
	Year Ended December 31,		Change	
($ in thousands)	**2022**	**2021**	**Amount**	**Percent**
Operating Expenses:				
Gathering and processing expense	$ 5,966	$ 3,787	$ 2,179	58%
Lease operating expense	$ 13,721	$ 10,755	$ 2,966	28%
Midstream operating expense	$ 461	$ 424	$ 37	9%
Production taxes	$ 4,123	$ 2,273	$ 1,850	81%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 4,487	$ 4,284	$ 203	5%
Depreciation and amortization expense – other	$ 679	$ 654	$ 25	4%
General and administrative	$ (2,551)	$ 743	$ (3,294)	(443)%
Operating Expenses ($/Boe)				
Gathering and processing expense	$ 3.15	$ 2.10	$ 1.05	50%
Lease operating expense	$ 7.26	$ 5.97	$ 1.29	22%
Production taxes (% of oil, natural gas and NGL sales)	5.8%	5.1%	0.7%	14%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 2.37	$ 2.38	$ (0.01)	0%
Depreciation and amortization expense – other	$ 0.36	$ 0.36	$ (0.00)	(1)%
General and administrative	$ (1.35)	$ 0.41	$ (1.76)	(427)%

Gathering and processing expense. Gathering and processing expense increased by $2.2 million, or 58% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to increased natural gas prices leading to higher fuel costs as well as an increase in production. Gathering and processing expense per Boe produced increased by $1.05 primarily due to higher fuel expense that fluctuated with the increase in commodity gas prices.

Lease operating expense. Lease operating expense increased $3.0 million, or 28% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. Of the total increases, $0.6 million was attributable to acquisitions that closed in the first quarter of 2022, and $1.5 million was attributable to an increase in workovers, repairs and maintenance, field office expenses, and non-operated costs. Overall increases were also partially attributable to the inflationary environment throughout 2022. Lease operating expense per Boe produced increased $1.29 primarily due to the reasons noted above.

Midstream operating expense. Midstream operating expense increased $37 thousand, or 9% for the year ended December 31, 2022, as compared to the year ended December 31, 2021.

Production taxes. Production taxes increased $1.9 million, or 81% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. This increase was primarily a result of an increase in the average selling price on all products, resulting in an increase of $1.7 million, and an increase in production, resulting in an increase of $0.2 million. Production taxes as a percentage of revenue increased from 5.1% for the year ended December 31, 2021 to 5.8% for the year ended December 31, 2022.

Depreciation, depletion, amortization and accretion expense. Depreciation, depletion, amortization and accretion expense for oil and natural gas properties increased by $0.2 million, or 5% for the year ended December 31, 2022, as compared to the year ended December31, 2021. The increase is primarily attributable to the increased production associated with the acquisitions that closed during 2022. Depreciation and amortization expense for other assets increased $25 thousand, or 4% for the year ended December 31, 2022, as compared to the year ended December 31, 2021, primarily due to additional assets acquired during the year.

General and administrative costs. General and administrative costs decreased $3.3 million, or 443% for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The decrease in general and administrative costs was primarily due to a $3.4 million reduction in equity compensation expense recorded in the year ended December 31, 2022. General and administrative expense includes cost recoveries from joint interest owners using contractual rates established by our joint operating agreements. Costs recovered for the years ended December 31, 2022 and 2021 were $6.5 million and $6.3 million, respectively.

Liquidity and Capital Resources

As a publicly traded partnership, our primary sources of liquidity and capital resources will be from cash flow generated by operating activities and borrowings under our New 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 following the completion of this offering. 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 and funding our development plan with our cash flow from operating activities. 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 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 lower decline nature of our Legacy Producing Assets and large inventory of horizontal drilling locations with average royalty burdens of less than 25%, coupled with our lower cash operating costs and owned midstream infrastructure, will support our ability to make cash distributions to our unitholders. We expect to maintain a conservative capital structure with the long-term goal of remaining substantially debt free. 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 commodity prices. Any such variations may be significant, and as a result, we may pay limited or even no cash distributions to our unitholders.

Historically, our business plan has focused on acquiring and then exploiting the development and production of our assets. We spent approximately $290.6 million in 2022 on development costs and our budget for 2023 is approximately $ million (of which $ million has been incurred as of June 30, 2023). For purposes of calculating our cash available for distribution, we define development costs as all of our capital expenditures, other than acquisitions. Our development efforts and capital for 2023 is focused on drilling Oswego wells given their high oil reserves and low breakeven costs.

During the year ended December 31, 2022, we spent approximately $270.2 million to drill 87.9 net wells and on related equipment, $9.1 million on remedial workovers and other capital projects, $11.3 million on midstream and other property and equipment capital projects, and $142.9 million on acquisitions.

Our 2023 capital expenditures program is largely discretionary and within our control. We could choose to defer a portion of these planned 2023 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, including acid to be used for our acid stimulation completion, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows and reduce our cash available for distribution to unitholders.

Based on current oil and natural gas price expectations for 2023, following the closing of this offering, we believe that our cash flow from operations, together with borrowings from time to time under our New Credit Facility, will be sufficient to fund our operations through 2023. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. For example, we expect a portion of our future capital expenditures to be financed with cash flows from operations derived from wells drilled on drilling locations not classified as proved reserves in our December 31, 2022 reserve report. The failure to achieve anticipated production and cash flow from operations from such wells could result in a reduction in future capital spending and/or our ability to pay distributions to unitholders. We cannot assure you that operations and other needed capital will be available on acceptable terms or at all.

Cash flows

The following table summarizes our predecessor's cash flows for the periods indicated:

	Predecessor			
	Six Months ended June 30,		Year ended December 31,	
(in thousands)	**2023**	**2022**	**2022**	**2021**
Net cash provided by operating activities	$ 275,145	$ 227,936	$ 553,542	$ 198,462
Net cash used in investing activities	$ (187,812)	$ (212,951)	$ (372,660)	$ (194,743)
Net cash used in financing activities	$ (67,904)	$ (27,236)	$ (210,737)	$ (4,584)

The following table summarizes BCE-Mach's cash flows for the periods indicated:

	BCE-Mach			
	Six Months ended June 30,		Year ended December 31,	
(in thousands)	**2023**	**2022**	**2022**	**2021**
Net cash provided by operating activities	$ 15,367	$ 42,802	$ 74,317	$ 68,696
Net cash used in investing activities	$ (20,192)	$ (2,500)	$ (11,401)	$ (5,109)
Net cash used in financing activities	$ (2,000)	$ (30,500)	$ (69,200)	$ (44,000)

The following table summarizes BCE-Mach II's cash flows for the periods indicated:

	BCE-Mach II			
	Six Months ended June 30,		Year ended December 31,	
(in thousands)	**2023**	**2022**	**2022**	**2021**
Net cash provided by operating activities	$ 12,620	$ 23,581	$ 44,735	$ 28,484
Net cash provided by (used in) investing activities	$ 1,643	$ (13,901)	$ (13,073)	$ (1,167)
Net cash used in financing activities	$ (22,245)	$ (16,500)	$ (41,947)	$ (10,400)

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

Predecessor

Net cash provided by operating activities.

Net cash provided by operating activities increased by $47.2 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase in net cash provided by operating activities is primarily attributable to the increase in production stemming from acquisitions throughout 2022 and additional drilling activities. The increase in production was partially offset with the decline in pricing of all products. Additionally, there was an increase of $61.0 million in cash received in relation to derivative settlements.

Net cash provided by (used in) investing activities.

Net cash used in investing activities decreased $25.1 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in net cash used in investing activities is primarily attributable to a decrease in cash used for acquisitions of $128.0 million, partially offset by an increase of cash used for drilling and completion activities of $99.6 million.

Net cash used in financing activities.

Net cash used in financing activities increased $40.7 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase in net cash used in financing activities is primarily attributable to a decrease in contributions from members of $65.0 million. This was partially offset with a decrease in distributions to members of $16.8 million in 2023. Additionally, there was also an increase in borrowings, net of repayments, on the Existing Credit Facilities of $7.9 million.

BCE-Mach

Net cash provided by operating activities.

Net cash provided by operating activities decreased by $27.4 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in cash provided by operating activities is primarily attributable to the decrease in average sales price for all products but was partially offset with a decrease of $27.9 million on cash paid on derivative settlements, due to lower oil and gas prices.

Net cash used in by investing activities.

Net cash used in investing activities increased by $17.7 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase in cash used in investing activities is primarily attributable to increased drilling activity.

Net cash used in financing activities.

Net cash used in financing activities decreased by $28.5 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in cash used in financing activities is primarily attributable to a decrease of $30.5 million in repayments. This was partially offset with an increase in distributions to members of $2.0 million.

BCE-Mach II

Net cash provided by operating activities.

Net cash provided by operating activities decreased by $11.0 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in net cash provided by operating activities is primarily attributable to the decrease in average sales price for all products, as well as a decrease in production. This was partially offset with an increase of $2.4 million on cash received on derivative settlements, due to lower oil and gas prices.

Net cash provided by (used in) investing activities.

Net cash provided by investing activities decreased by $15.5 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The decrease in net cash used in investing activities is primarily attributable a decrease in cash used in acquisitions of $13.7 million, coupled with an increase in cash provided by divestitures of $2.0 million in the period ended June 30, 2023.

Net cash used in financing activities.

Net cash used in financing activities increased by $5.7 million for the six-month period ended June 30, 2023, as compared to the six-month period ended June 30, 2022. The increase in net cash used in financing activities is primarily attributable to a $10.2 million increase in distributions to members made in 2023. This was partially offset by a decrease in cash used in repayments of borrowings of $4.5 million.

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

Predecessor

Net cash provided by operating activities.

Net cash provided by operating activities increased by $355.1 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in net cash provided by operating activities is primarily attributable to the increase in average sales price for all products, as well as an increase in production stemming from acquisitions throughout 2022 and additional drilling activities. This was partially offset with an increase of $34.8 million on cash paid on derivative settlements, due to higher oil and gas prices.

Net cash used in investing activities.

Net cash used in investing activities increased $177.9 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in net cash used in investing activities is primarily attributable to an increase in drilling and completion activity of $195.8 million in 2022. This was partially offset by a decrease in cash used for acquisitions of $20.6 million.

Net cash used in financing activities.

Net cash used in financing activities increased $206.2 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in net cash used in financing activities is primarily attributable to an increase of distributions to members of $128.9 million in 2022, along with a decrease in contributions from members of $36.5 million. Additionally, there was also a decrease in borrowings, net of repayments, on the Existing Credit Facilities of $43.0 million year over year.

BCE-Mach

Net cash provided by operating activities.

Net cash provided by operating activities increased by $5.6 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in cash provided by operating activities is primarily attributable to the increase in average sales price for all products, but was partially offset with an increase of $40.9 million on cash paid on derivative settlements, due to higher oil and gas prices.

Net cash used in by investing activities.

Net cash used in investing activities increased by $6.3 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in cash used in investing activities is primarily attributable to increased drilling activity.

Net cash used in financing activities.

Net cash used in financing activities increased by $25.2 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in cash used in investing activities is primarily attributable to $20.0 million in distributions to members made in 2022.

BCE-Mach II

Net cash provided by operating activities.

Net cash provided by operating activities increased by $16.3 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in net cash provided by operating activities is primarily attributable to the increase in average sales price for all products, as well as an increase in production. This was partially offset with an increase of $3.1 million on cash paid on derivative settlements, due to higher oil and gas prices.

Net cash used in investing activities.

Net cash used in investing activities increased by $11.9 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in net cash used in investing activities is primarily attributable to acquisitions made in 2022 for $12.0 million.

Net cash used in financing activities.

Net cash used in financing activities increased by $31.5 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021. The increase in net cash used in financing activities is primarily attributable to a $31.4 million increase in distributions to members made in 2022.

Debt agreements

Our predecessor, BCE-Mach and BCE-Mach II are currently party to revolving credit facilities. Contemporaneously with the closing of this offering, we will enter into the New Credit Facility and repay in full and terminate each of these Existing Credit Facilities.

Existing Credit Facilities

Predecessor Credit Facility. Our predecessor entered into a credit agreement for a revolving credit facility (the "predecessor credit facility") with a syndicate of banks, including MidFirst Bank, who serves as administrative agent and issuing bank. The predecessor credit facility provides for a maximum of $400.0 million, subject to commitments of $100.0 million as of June 30, 2023 and matures in May 2026. Outstanding obligations under the predecessor credit facility are secured by substantially all of our predecessor's assets. The amount available to be borrowed under the predecessor credit facility is subject to a borrowing base that is redetermined semiannually each May and November in an amount determined by the lenders. As of June 30, 2023, there was $91.9 million outstanding under the predecessor credit facility.

BCE-Mach Credit Facility. BCE-Mach entered into a revolving credit facility (the "BCE-Mach credit facility") on September 2, 2022 with a syndicate of banks, including MidFirst Bank who serves as sole book runner and lead arranger, maturing in September 2026. Outstanding obligations under the BCE-Mach credit facility are secured by substantially all of BCE-Mach's assets. The credit agreement provides for a revolving credit facility in the maximum of $200.0 million, subject to commitments of $100.0 million as of June 30, 2023. As of June 30, 2023, $65.0 million was outstanding under the BCE-Mach credit facility and $5 million in outstanding letters of credit, which reduces the availability under the credit facility on a dollar-for-dollar basis. The amount available to be borrowed under the BCE-Mach credit facility is subject to a borrowing base that is redetermined semiannually each May and November in an amount determined by the lenders.

BCE-Mach II Credit Facility. BCE-Mach II entered into a revolving credit facility (the "BCE-Mach II credit facility") with a syndicate of banks, including East West Bank, who serves as sole book runner and lead arranger, maturing in September 2024. Outstanding obligations under the BCE-Mach II credit facility are secured by substantially all of BCE-Mach II's assets. The credit agreement provides for a revolving credit facility in the maximum of $250.0 million, subject to a borrowing base of $26.0 million as of June 30, 2023. As of June 30, 2023,

$17.1 million was outstanding under the BCE-Mach II credit facility. The amount available to be borrowed under the BCE-Mach II credit facility is subject to a borrowing base that is redetermined semiannually each April and October in an amount determined by the lenders.

New Credit Facility

Contemporaneously with the closing of this offering, we expect to enter into a new credit facility led by (the "New Credit Facility"). The New Credit Facility is expected to have a total facility size of $ million, an initial borrowing base of $ million and available capacity of $ million.

We expect that the credit agreement will contain various affirmative, negative and financial maintenance covenants. These covenants would, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, transactions with affiliates and entering into certain swap agreements and require the maintenance of certain financial ratios. We also expect that the credit agreement will contain customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control.

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.

Firm transportation contracts

We are a party to firm transportation contracts for the transport of natural gas. We paid approximately $3.3 million in firm transportation contracts for the year ended December 31, 2022 and $1.8 million for the six months ended June 30, 2023 and expect to pay approximately $10.6 million in firm transportation contracts for the remainder of 2023 through 2025. For further information on firm transportation contracts, see the notes to our audited financial statements included elsewhere in this prospectus.

Operating lease obligations

Our operating lease obligations include long-term lease payments for office space, vehicles, equipment related to exploration, development and production activities, as well as long-term obligations expected to be incurred for commencing leases commencing. We paid approximately $8.7 million in operating lease obligations for the year ended December 31, 2022 and $7.7 million for the six months ended June 30, 2023 and expect to pay approximately $18.2 million in operating lease obligations for the remainder of 2023 through 2025. For further information on our operating lease obligations, see the notes to our audited financial statements included elsewhere in this prospectus.

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.

Commodity price risk

Oil and gas revenue

Our revenue and cash flow from operations are subject to many variables, the most significant of which is the volatility of commodity prices. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by global economic factors, pipeline capacity constraints, inventory levels, basis differentials, weather conditions and other factors. Commodity prices have long been volatile and unpredictable, and we expect this volatility to continue in the future.

There can be no assurance that commodity prices will not be subject to continued wide fluctuations in the future. A substantial or extended decline in such prices could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and gas reserves that may be economically produced, which could result in impairments of our oil and gas properties.

Commodity derivative activities

To reduce the impact of fluctuations of commodity prices on our total revenue and other operating income, we have historically used, and we expect to continue to use, commodity derivative instruments, primarily swaps, to hedge price risk associated with a portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate the potential effects of the variability in cash flow from operations due to fluctuations in commodity prices and provide increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in prices and may partially limit our potential gains from future increases in prices. We do not enter derivative contracts for speculative trading purposes. The Existing Credit Facilities contain, and the New Credit Facility is expected to contain, various covenants and restrictive provisions which, among other things, limit our ability to enter into commodity price hedges exceeding a certain percentage of production.

Our hedging activities are intended to support oil and natural gas prices at targeted levels and manage our exposure to natural gas price volatility. Under swap contracts, the counterparty is required to make a payment to us for the difference between the swap price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the swap price. We are required to make a payment to the counterparty for the difference between the swap price and the settlement price if the swap price is below the settlement price.

The following table provides a pro forma summary of the financial oil and natural gas derivative contracts that we had in place as of December 31, 2022:

	2023	2024	2025
Swaps – Natural Gas			
Volume (MMBtu)	7,999	—	—
Fixed Price	$ 4.00	$ —	$ —
Swaps – Oil			
Volume (MBbl)	748	—	—
Fixed Price	$ 57.24	$ —	$ —

Counterparty and customer credit risk

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of a contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. 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. The creditworthiness of our counterparties is subject to periodic review. As of December 31, 2022, we had derivative instruments in place with three different counterparties, with Morgan Stanley accounting for more than 50% of the fair value. We believe our counterparties currently represent acceptable credit risks. We are not required to provide credit support or collateral to our counterparties under current contracts, nor are they required to provide credit support or collateral to us.

Substantially all of our revenue and receivables result from oil and gas sales to third parties operating in the oil and gas industry. Our receivables also include amounts owed by joint interest owners in the properties we operate. Both our purchasers and joint interest partners have recently experienced the impact of significant commodity price volatility as discussed above under "— Commodity Price Risk — Oil and Gas Revenue." This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in commodity prices and economic and other conditions. In the case of joint interest owners, we often have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings.

Interest rate risk

Variable rate debt

At June 30, 2023, we had $174 million of debt outstanding under the Existing Credit Facilities, as adjusted for the Reorganization Transactions. Borrowings outstanding under the Existing Credit Facilities bore an effective interest rate between 8.3% and 8.5% as of June 30, 2023. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the assumed weighted average interest rate on our variable interest debt would be approximately $1.7 million per year based on our borrowings outstanding at June 30, 2023.

Interest derivative activities

As of June 30, 2023, we did not have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness, but we may enter into such derivative arrangements in the future. To the extent we enter into any such interest rate derivative arrangement, we would be subject to risk for financial loss.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions we consider to be most significant to our financial statements are discussed below.

Oil and Natural Gas Accounting and Reserves

We account for our oil and natural gas producing activities using the full cost method of accounting, which is dependent on the estimation of proved reserves to determine the rate at which we record depletion on our oil and natural gas properties. On a quarterly basis, using the estimate of proved reserves, we evaluate our oil and natural gas properties to determine whether they have been impaired using the full cost ceiling impairment test. Further, we utilize estimated proved reserves to assign fair value to acquired proved oil and natural gas properties. As such, we consider the estimation of proved reserves to be a critical accounting estimate.

Estimates of natural gas and oil reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from our estimates.

Business Combinations

We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 — Business Combinations, and involves the use of significant judgment. Under the acquisition method of accounting, a business combination is accounted for at a purchase price based on the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values.

The most significant assumptions relate to the estimated fair values assigned to our proved oil and natural gas properties. The assumptions made in performing these valuations include future production volumes, future commodity prices and costs, future operating and development activities, projections of oil and gas reserves and a weighted average cost of capital rate. There is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. In addition, differences between the future commodity prices when acquiring assets and the historical 12-month average trailing price to calculate ceiling test impairments of upstream assets may impact net earnings.

Recently Issued Accounting Pronouncements

A summary of recent accounting pronouncements and our assessment of any expected impact of these pronouncements if known is included in Note 2 to the audited consolidated financial statements of our predecessor included elsewhere in this prospectus.

Internal controls and procedures

We are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC's rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Though we will be required to disclose material changes made to our internal controls and procedures on a quarterly basis, we will not be required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 until the year following our first annual report to be filed with the SEC. We have elected to avail ourselves of the provision of the JOBS Act that permits emerging growth companies to take advantage of an extended transition period to comply with new or revised accounting standards applicable to public companies. We will not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls over financial reporting until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act.

BUSINESS AND PROPERTIES

Our Company

We are an independent upstream oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western Oklahoma, Southern Kansas and the panhandle of Texas. Our experienced management team, led by industry veteran Tom L. Ward, possesses deep operational and industry experience, particularly in Oklahoma and the Anadarko Basin. We leverage our extensive experience to identify the most attractive exploitation and development opportunities and optimize the production of current wells, efficiently drill our existing inventory of undeveloped locations and identify attractive low-risk acquisition opportunities.

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 lower decline nature of our Legacy Producing Assets and large inventory of horizontal drilling locations with average royalty burdens of less than 25%, coupled with our lower cash operating costs and owned midstream infrastructure, will support our ability to make cash distributions to our unitholders. We expect to maintain a conservative capital structure with the long-term goal of remaining substantially debt free. 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 commodity prices. Any such variations may be significant, and as a result, we may pay limited or even no cash distributions to our unitholders.

We seek to maximize cash distributions to unitholders through a combination of the development of our existing properties, primarily using our cash flow from operating activities, and the acquisition of producing properties. Our current acreage position in the Anadarko Basin is characterized as oil-rich with considerable natural gas content, notable historical production, low decline rates and average royalty burdens of less than 25%. Through a series of acquisitions since our inception, we have accumulated an acreage position consisting of approximately 936,000 net acres, of which 99% is held by production, and over 2,000 identified horizontal drilling locations, of which more than 750 of these are located in the Oswego formation, a prolific reservoir in north-central Oklahoma. We consider our large inventory of horizontal drilling locations to be low-risk based on information gained from the large number of existing wells in the area, industry activity surrounding our acreage, and the consistent and predictable geology surrounding our positions. We believe the combination of our large inventory of low-risk drilling locations with the low decline production profile of our Legacy Producing Assets leads to a sustainable production profile.

We focus on controlling costs and maintaining financial discipline, which enables us to prudently develop our assets while generating significant cash available for distribution. Our strategy is to enhance existing production and reduce costs by right-sizing field operations to cost-effectively extract oil and natural gas from producing reservoirs. Our culture of cost control and production optimization has resulted in substantially lower cash operating costs than our peers.

We believe a key competitive advantage that we have over other operators is that we own an extensive portfolio of complementary midstream assets that are integrated with our upstream operations. These assets include gathering systems, processing plants and water infrastructure. Our midstream assets enhance the value of our properties by allowing us to optimize pricing, increase flow assurance and eliminate third-party costs and inefficiencies. In addition, our owned midstream systems generate third-party revenue, which effectively reduces the cost of operating our midstream assets and reduces our average breakeven costs compared to other operators. We believe the Anadarko Basin is uniquely positioned with legacy takeaway pipeline infrastructure enabling our oil, natural gas and NGLs to be easily transported to premium markets, such as Cushing, Oklahoma.

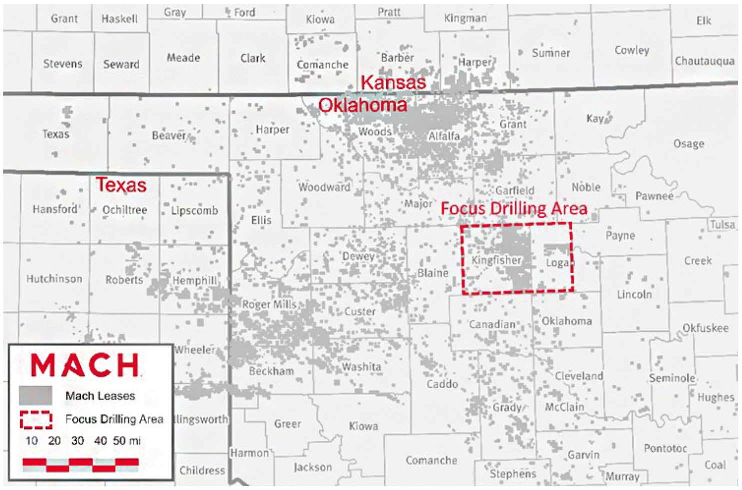
Our Properties

Our assets are located throughout Western Oklahoma, Southern Kansas and the panhandle of Texas and consist of approximately 4,500 gross operated PDP wells. We define our Focus Drilling Area assets as all of our horizontal properties that are located in Kingfisher and Logan Counties, Oklahoma, and we define our "Legacy Producing Assets" as all of our legacy producing properties which are not in the Focus Drilling Area, as shown in the chart below. Based on our reserve report as of June 30, 2023, 57% of our production is attributable to our Legacy Producing Assets, which have an average expected annual decline rate of approximately 15%. Our wells are located almost exclusively in the Anadarko Basin, which has a more predictable production profile compared to less mature basins. Our production benefits from both the diversity of our well vintage and the lack of concentration in any specific sub-area. Within our large and diversified PDP base, no single well accounts for more than 1% of our PDP PV-10.

Within our operating areas, our assets are prospective for multiple formations, most notably the Oswego, Meramec/Osage and Mississippi Lime formations. Our experience in the Anadarko Basin and these formations allows us to generate significant cash available for distribution from these low declining assets in a variety of commodity price environments.

In addition to our portfolio of producing wells, our properties include over 2,000 identified horizontal drilling locations that we believe will allow us to maintain our production and support future cash distributions to our unitholders.

Additionally, we own a portfolio of midstream assets which support our leases. As of June 30, 2023, approximately 75% of our operated PDP reserves (and approximately 66% of our total PDP reserves) are supported by Company-owned midstream infrastructure.



The following table presents our historical estimated oil, natural gas and NGL proved reserves as of June 30, 2023.

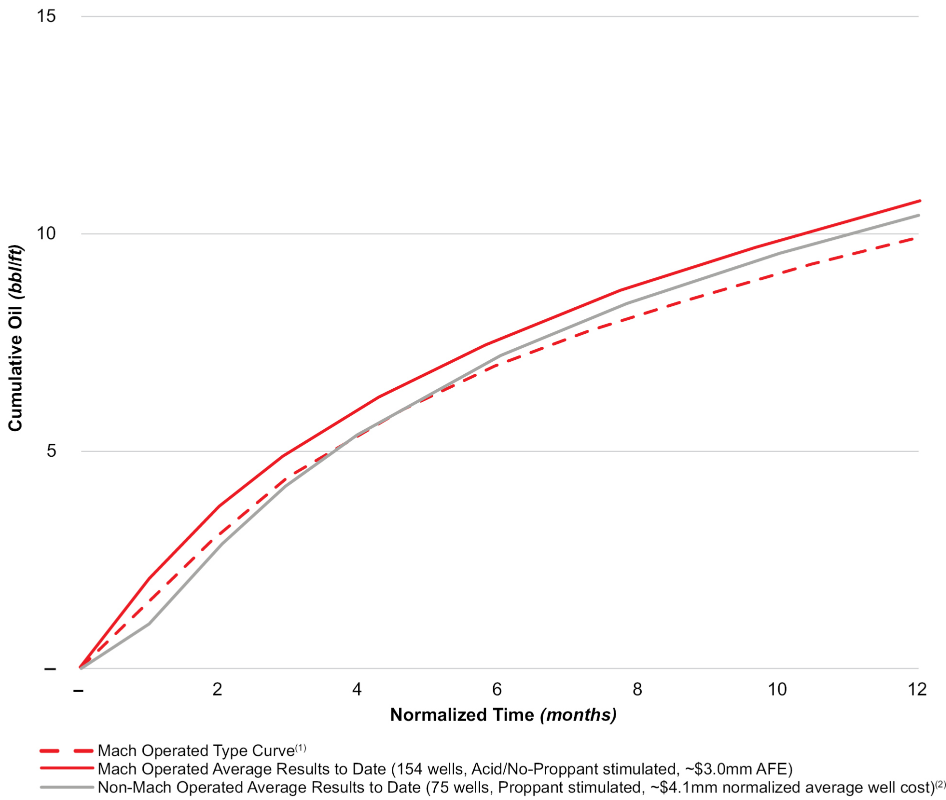
	Estimated Proved Reserves as of June 30, 2023		Estimated Probable Reserves as of June 30, 2023(1)(2)
	Proved Developed Reserves(1)	Proved Reserves(1)	
Oil (MBbl)	40,876	53,029	72,868
Natural gas (MMcf)	782,727	811,507	373,477
NGLs (MBbl)	50,190	50,911	19,576
Total equivalent (MBoe)(3)	221,520	239,191	154,690
PV-10 (in millions)(4)	$ 2,131	$ 2,435	$ 1,039
Standardized Measure (in millions)(5)	$ 2,131	$ 2,435	—

(1) Our estimated net proved and probable reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. For more information on the prices used, see "Prospectus Summary — Summary of Reserve, Production and Operating Data — Summary of Reserves."

(2) Estimates of probable reserves, and the future cash flows related to such estimates, are inherently imprecise and are more uncertain than estimates of proved reserves and the future cash flows related to such estimates but have not been adjusted for risk due to such uncertainty. Therefore, estimates of probable reserves, and the future cash flows related to such estimates, may not be comparable to estimates of proved reserves and the future cash flows related to such estimates and should not be summed arithmetically with estimates of proved reserves and the future cash flows related to such estimates. For more information regarding the presentation of probable reserves, see "Business and Properties — Our Operations — Preparation of Reserve Estimates."

(3) Presented on an oil-equivalent basis using a conversion of six thousand cubic feet of natural gas to one stock tank barrel of oil. This conversion is based on energy equivalence and not on price or value equivalence.
(4) For more information on how we calculate PV-10 and a reconciliation of proved reserves PV-10 to its nearest GAAP measure, see “Prospectus Summary — Summary of Reserve, Production and Operating Data — Summary of Reserves” and “Prospectus Summary — Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure.” With respect to PV-10 calculated as of an interim date, it is not practicable to calculate the taxes for the related interim period because GAAP does not provide for disclosure of Standardized Measure on an interim basis.
(5) For more information on how we calculate Standardized Measure of proved reserves, see “Prospectus Summary — Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure.”

Our near-term drilling program is focused on horizontal development in Kingfisher and Logan Counties, Oklahoma. The two primary, productive formations in this area are the Oswego and Meramec/Osage. The Oswego is the most oil rich and economic formation within our inventory. In the early stages of the Oswego horizontal development, a mixture of standard completion fluids and proppant were utilized in the stimulation. We have successfully further lowered our well costs to $3.0 million per well in the Oswego by using drilling efficiencies and utilizing acid in lieu of proppant within the stimulation. As observed in the chart below, the 154 acid-only stimulated wells that we drilled are performing comparably to the proppant-stimulated 75 Oswego wells producing in Kingfisher County, Oklahoma. The below illustrates the average oil production results from the Oswego as of August 2023:



(1) Based on Management’s estimates.
(2) Data and analytics derived from Enverus Core. Includes all offset horizontal wells drilled in Oswego formation with reported proppant loading. Normalized to 5,121 feet.

In addition to the Oswego, there have been over 775 wells in the Meramec/Osage formations drilled and over 1,850 wells in the Mississippi Lime formation drilled on our acreage. Our assets have extensive production histories and high drilling success rates. Accordingly, we believe our acreage has been significantly delineated by our own drilling success and by the success of offset operators.

The below table summarizes our identified horizontal drilling locations as of June30, 2023.

	Identified Horizontal Drilling Locations(1)(2)			
Target Horizontal Zones	**Focus Drilling Area Operated**	**Focus Drilling Area Non-Operated**	**Legacy Producing Assets**	**Total**
Oswego	437	314	0	751
Meramec/Osage	265	228	0	493
Mississippi Lime	0	0	778	778
Total Horizontal Locations	702	542	778	2,022
Average Working Interest	82.6%	16.4%	29.7%	44.5%
Average Net Revenue Interest	69.0%	14.1%	24.0%	37.0%

(1) "— Our Operations" contains a description of our methodology used to determine our drilling locations.

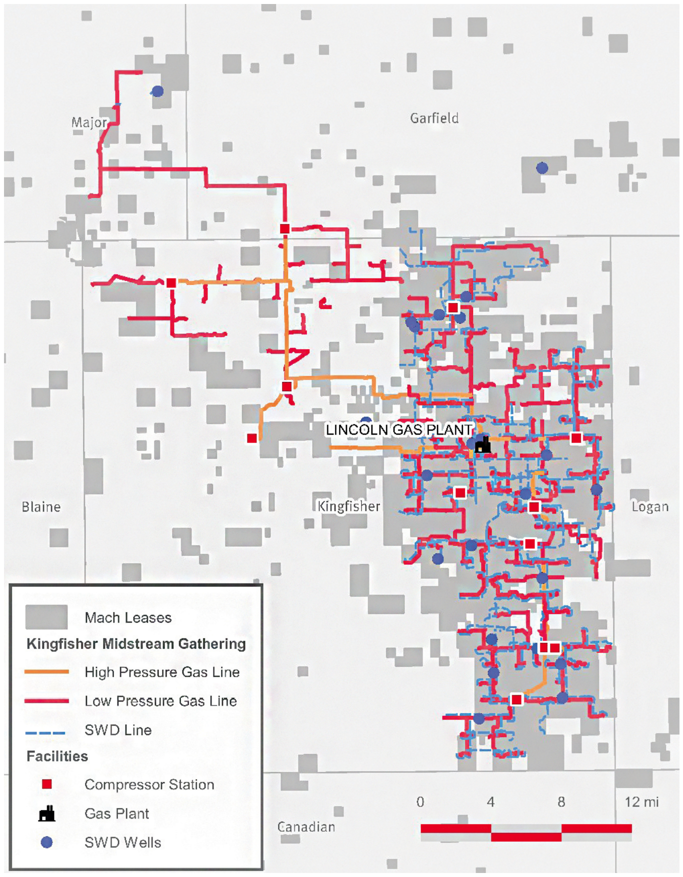
(2) The above table includes 665 drilling locations that have not been evaluated by Cawley, Gillespie & Associates Inc., our independent reserve engineer, that were based solely on the internal evaluations of the Company's management, along with 1,357 of our total drilling locations that have been evaluated by Cawley, Gillespie & Associates Inc., our independent reserve engineer. See "Risk Factors — Risks Related to Our Business — A portion of our estimated drilling locations are based on our management's internal estimates and were not based on evaluations prepared by Cawley, Gillespie & Associates Inc."

We have estimated our drilling locations based on well spacing assumptions for the areas in which we operate and upon the evaluation of our horizontal drilling results and those of other operators in our area, combined with our interpretation of available geologic and engineering data. The drilling locations on which we actually drill will depend on the availability of capital, drilling rigs and labor, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in our ability to add proved reserves to our existing proved reserves. See "Risk Factors — Risks Related to Our Business — Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling."

STACK Area Gas Gathering & Processing ("G&P") and Water Infrastructure

We own a significant complementary portfolio of midstream assets, including gas gathering and processing assets and water infrastructure assets, that supports the development of our properties in Kingfisher County in Oklahoma. For example, the recently constructed Lincoln gas processing plant that we acquired in 2020 has 260 MMcf/d of processing capacity, which is supported by approximately 460 miles of gas gathering lines with approximately 430 receipt point connections, and 27 compressors totaling 35,880 horsepower. Our processing complex has interconnects to both the PEPL and OGT system.

Our STACK water infrastructure consists of approximately 300 miles of owned gathering pipeline, and our water disposal assets consist of 20 disposal wells with approximately 377,000 BWPD permitted capacity.



Other Gas Gathering & Processing and Water Infrastructure

In addition to our STACK midstream assets, we own and/or operate other midstream assets, including gas gathering and processing, water infrastructure and compression assets that provide additional margin enhancement for our upstream business.

Within these other midstream assets, our 56% owned and operated Laredo gas gathering system, located in Roger Mills County, Oklahoma and Hemphill County, Texas, has approximately 166 MMcf/d of gathering capacity, which is supported by approximately 160 miles of pipeline. Our 50% owned and contract operated McLean processing facility, located in Gray County, Texas, has approximately 23 MMcf/d of processing capacity and is supported by our wholly owned McLean gathering assets consisting of approximately 510 miles of pipeline spanning seven counties in western Oklahoma and the Texas Panhandle. Our 50% owned and contract operated Madill processing facility, located in Marshall County, Oklahoma, has approximately 40 MMcf/d of processing capacity and is supported by our wholly owned Madill gathering assets consisting of approximately 180 miles of pipeline spanning Marshall and Bryan Counties, Oklahoma. Our wholly owned and operated Elmore City gas gathering and processing facility, located in Garvin County, Oklahoma has approximately 30 MMcf/d of processing capacity supported by approximately 60 miles of pipeline. Our 50% owned Mississippi Lime water infrastructure, located in Alfalfa, Woods and Grant Counties, Oklahoma, aids in the disposal of produced water generated by our operations consisting of approximately 580 miles of pipeline and 35 disposal wells with approximately 300,000 BWPD permitted capacity. Our compression assets consist of a well site compression fleet of approximately 500 units with approximately 89,000 aggregate horsepower.

Development Plan and Capital Budget

Historically, our business plan has focused on acquiring and then exploiting the development and production of our assets. Funding sources for our acquisitions have included proceeds from borrowings under our revolving credit facilities, contributions from our equity partners and cash flow from operating activities. We spent approximately $290.6 million in 2022 on development costs and our budget for 2023 is approximately $ million (of which $ million has been incurred as of June 30, 2023). For purposes of calculating our cash available for distribution, we define development costs as all of our capital expenditures, other than acquisitions. Our development efforts and capital for 2023 is focused on drilling Oswego wells given their high oil reserves and low breakeven costs.

During the year ended December 31, 2022, we spent approximately $270.2 million to drill 87.9 net wells and on related equipment, $9.1 million on remedial workovers and other capital projects, $11.3 million on midstream and other property and equipment capital projects, and $142.9 million on acquisitions.

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.

Our development plan and capital budget are based on management's current expectations and assumptions about future events. While we consider these expectations and assumptions to be reasonable, they are subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated commodity prices, the availability of necessary equipment, infrastructure, drilling rigs, labor and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions and drilling and completion costs.

Our Business Strategies

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

- ***Focus on low decline Legacy Producing Assets with additional meaningful horizontal development inventory.*** Our ability to generate significant cash flow is supported by the predictable low decline production profile of our Legacy Producing Assets, which have an average expected annual decline rate of approximately 15%. Based on our reserve report as of June 30, 2023, 57% of our production is attributable to our low decline Legacy Producing Assets. In addition, we believe we have the ability to maintain or modestly grow our average annual production with the development of our horizontal Focus Drilling Area inventory. We have identified over 2,000 horizontal drilling locations within our 936,000 net acre position, of which at a 10% internal rate of return, over 750 are currently economic at $50 per barrel of oil, over 1,100 at $70 per barrel of oil and over 2,000 at $90 per barrel of oil, each assuming a flat natural gas price per Mcf of 1/20th of the assumed oil price.

- ***Maximize well economics by leveraging midstream infrastructure.*** Our midstream infrastructure assets both reduce our overall upstream costs and generate incremental third-party revenue. In our Oswego formation drilling locations, we estimate that, the oil price necessary to yield a 10% rate of return on invested capital would be approximately $45.47 per barrel of oil equivalent without our midstream assets. We estimate that our complementary midstream assets reduce our average breakeven costs for our Oswego formation drilling locations tied to our owned midstream infrastructure by approximately $4.18 per barrel of oil equivalent to approximately $41.29 per barrel. This reduction consists of the average net cost savings attributable to our working interest resulting from the utilization of our owned midstream infrastructure for gas processing and transportation and water disposal, and the addition of the incremental third-party midstream revenue attributable to the non-operated portion of the working interest that we do not own. After adding the benefit of our midstream infrastructure, we believe these breakeven costs have comparable economics to the Midland and Delaware Basins.

- ***Maintain low operating cost structure to support meaningful cash available for distribution.*** Our average cash operating costs during the twelve months ended June 30, 2023, including the benefit of our midstream infrastructure assets, were $12.51 per barrel of oil equivalent, which is 16% lower on average than other unconventional focused operators, and 58% lower on average than other conventional focused operators during the same period. We believe that our low cost structure will allow us to make unitholder cash distributions during a negative commodity cycle.

- ***Leverage industry expertise to improve operations and pursue opportunistic acquisitions in Oklahoma.*** Led by industry veteran Tom L. Ward, our senior management team has built lasting relationships with sellers and operators throughout the Anadarko Basin and has developed a track record of acquiring assets at consistently attractive valuations. We believe we can continue to execute opportunistic and accretive transactions that complement our operations in the Anadarko Basin, utilizing our technical expertise to identify acquisition opportunities where our production and cost optimization strategies will yield the greatest returns.

- ***Ensure financial flexibility with conservative leverage and ample liquidity.*** We intend to conduct our operations through cash flow generated from operations with a focus on maintaining a disciplined balance sheet with little to no outstanding debt. Due to our historically 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 strong liquidity profile and remaining substantially debt free. Further, to mitigate the risk associated with volatile commodity prices and to further enhance the stability of our cash flow available for distribution, from time to time we may opportunistically hedge a portion of our production volumes at prices we deem attractive.

Our Strengths

We have a number of differentiated strengths that we believe help us successfully execute our business strategy, including:

- ***Strong production and cash flow across a large acreage position.*** Our average net daily production for the month ended June 30, 2023 was approximately 68 MBoe/d, with approximately 4,500 gross operated wells, and an average working interest of approximately 75%. We own extensive acreage in the Anadarko Basin, with approximately 936,000 net acres, approximately 99% of which is held by production. We believe our large acreage position enables us to optimize our development plan and support significant cash flow generation. For the six months ended June 30, 2023 and year ended December 31, 2022, on a pro forma basis, we generated $199million and $643 million of net income, respectively, $256 million and $714 million of Adjusted EBITDA, respectively, and $46 million and $406 million of cash available for distribution, respectively. See "Prospectus Summary — Non-GAAP Financial Measures" and "Our Cash Distribution Policy and Restrictions on Distributions — Unaudited Pro Forma Cash Available for Distribution for the Year Ended December 31, 2022 and the Twelve Months Ended June 30, 2023."

- ***Attractive portfolio of large and contiguous core acreage blocks supported by company owned midstream infrastructure.*** Since our founding, we have accumulated an acreage position consisting of approximately 936,000 net acres, of which 99% is held by production, and over 2,000 identified horizontal drilling locations, of which more than 750 are located in the Oswego formation. This large acreage position provides flexibility to accelerate our drilling program or execute opportunistic developments as conditions warrant. In addition, we own substantial gathering and processing assets, which improves our cost structure and enhances the stability of our hydrocarbon flows. We believe our acreage footprint and midstream systems allows us to monetize our production at favorable realized prices and reduces our operating costs while providing us with additional incremental third party revenue streams.

- ***Optimized operations designed to make cash distributions to unitholders.*** Our entrepreneurial culture focuses on operational optimization, cost-minimization, and nimble development to ultimately deliver cash distributions to unitholders across commodity cycles. Our asset profile consists of a large, low cost, and low declining PDP asset, complemented by low-cost horizontal development. Our significant operating experience in the Anadarko Basin and economic advantage conferred by our midstream infrastructure significantly reduces lifting costs relative to other operators. For example, for the twelve months ended June 30, 2023, we achieved a cash operating cost of approximately $12.51 per barrel of oil equivalent, inclusive of the benefit received from our midstream assets. Further, in the early stages of the Oswego horizontal development, a mixture of standard completion fluids and proppant were utilized in the stimulation. Since 2021, we have successfully further lowered our well costs to $3.0 million per well in the Oswego by using drilling efficiencies and utilizing acid in lieu of proppant within the stimulation. Due to our low completion costs, low operating costs, and our midstream advantage, we believe the average breakeven price for our Oswego drilling locations is $41.29 price per barrel of oil.

- ***Experienced management team with established record of value creation.*** We believe our management team's experience in the Anadarko Basin offers a distinguishing advantage. The members of management have an average of 32 years of experience in the oil and gas industry and have successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets. Additionally, our Chief Executive Officer, Tom L. Ward, has over a 40-year history in the oil and gas industry. Further, through our team's history of operating in Oklahoma, we have built lasting relationships with sellers and developed a track record of successfully acquiring and integrating assets at attractive valuations. Since our founding, we have successfully executed 15 acquisitions for an aggregate purchase price of approximately $950 million, increasing our net acreage to 936,000, and our average net daily production for the month ended June 30, 2023 was approximately 68 MBoe/d. Additionally, during the same period, we distributed approximately $616 million in cash to our members. We believe our management team has the experience, expertise and commitment to create significant value in the form of cash distributions to our unitholders.

- ***Conservatively capitalized balance sheet and strong liquidity profile.*** Since our founding, we have practiced financial conservatism and maintained a strong balance sheet with low leverage. Due to our significant existing low-decline production base, our business generates significant operating cash flow. Upon consummation of this offering, we expect to have little to no debt and substantial liquidity, which will provide us further financial flexibility to fund our capital expenditures and execute our strategic plan.

Our Operations

Oil and Gas Reserves and Operating Data

Reserve data

The information with respect to our estimated proved and probable reserves based on SEC pricing presented below has been prepared in accordance with the rules and regulations of the SEC.

Reserves Presentation

The following tables provide a summary of our estimated proved and probable reserves and related PV-10 of proved and probable reserves as of June 30, 2023 and our estimated proved reserves and related PV-10 of proved reserves as of December 31, 2022, using SEC pricing, based on evaluations prepared by Cawley, Gillespie & Associates Inc., our independent reserve engineer. See "— Preparation of Reserve Estimates" for the definitions of proved and probable reserves and the technologies and economic data used in their estimation. Prices were adjusted for quality, energy content, transportation fees and market differentials, as applicable. The risk factors contained in this prospectus including "Risk Factors — Risks Related to Our Business — Oil and natural gas and NGL prices are volatile. A sustained decline in prices could adversely affect our business, financial condition, cash available for distribution and results of operations, liquidity and our ability to meet our financial commitments or cause us to delay our planned capital expenditures" and "Risk Factors — Risks Related to Our Business — Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves," contain more information regarding the uncertainty associated with price and reserve estimates.

Pro Forma Summary Reserve Data

Our historical SEC reserves, PV-10 and Standardized Measure of proved reserves were calculated using oil and gas price parameters established by current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions ("SEC Pricing"). These prices were adjusted for differentials on a per-property basis, which may include local basis differential, fuel costs and shrinkage. All prices are held constant throughout the lives of the properties.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "— Oil and Gas Reserves and Operating Data — Reserve Data" in evaluating the material presented below.

	Pro Forma Combined As of June 30, 2023 SEC Pricing[(1)]	Pro Forma Combined As of December 31, 2022 SEC Pricing[(1)]
Proved Developed:		
Oil (MBbl)	40,876	43,306
Natural gas (MMcf)	782,727	838,298
Natural gas liquid (MBbl)	50,190	59,761
Oil equivalent (MBoe)	221,520	242,782
PV-10 (in millions)[(2)]	$ 2,131	$ 3,334
Proved Undeveloped:		
Oil (MBbl)	12,153	23,438
Natural gas (MMcf)	28,781	144,380
Natural gas liquid (MBbl)	721	9,978
Oil equivalent (MBoe)	17,671	57,480
PV-10 (in millions)[(2)]	$ 304	$ 724
Total Proved:		
Oil (MBbl)	53,029	66,744
Natural gas (MMcf)	811,507	982,678
Natural gas liquid (MBbl)	50,911	69,739
Oil equivalent (MBoe)	239,191	300,262
Standardized Measure (in millions)[(2)]	$ 2,435	$ 4,058
PV-10 (in millions)[(2)]	$ 2,435	$ 4,058
Probable:[(3)]		
Oil (MBbl)	72,868	—
Natural gas (MMcf)	373,477	—
Natural gas liquid (MBbl)	19,576	—
Oil equivalent (MBoe)	154,690	—
PV-10 (in millions)[(2)]	$ 1,039	$ —

(1) Our estimated net proved and probable 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 $6.358 per Mcf for natural gas at January 1, 2023 and $82.82 per barrel for oil and $4.763 per MMBtu for natural gas at June 30, 2023. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, fuel costs and shrinkage.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved and probable oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. For more information on how we calculate PV-10 and a reconciliation of proved reserves PV-10 to its nearest GAAP measure, see "Prospectus Summary — Non-GAAP Financial Measures — Reconciliation of PV-10 to Standardized Measure." With respect to PV-10 calculated as of an interim date, it is not practicable to calculate the taxes for the related interim period because GAAP does not provide for disclosure of Standardized Measure on an interim basis.

(3) Estimates of probable reserves, and the future cash flows related to such estimates, are inherently imprecise and are more uncertain than estimates of proved reserves and the future cash flows related to such estimates but have not been adjusted for risk due to such uncertainty. Therefore, estimates of probable reserves, and the future cash flows related to such estimates, may not be comparable to estimates of proved reserves and the future cash flows related to such estimates and should not be summed arithmetically with estimates of proved reserves and the future cash flows related to such estimates. For more information regarding the presentation of probable reserves, see "Business and Properties — Our Operations — Preparation of Reserve Estimates."

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2022 and June 30, 2023 included in this prospectus are based on evaluations prepared by the independent petroleum engineering firm of Cawley, Gillespie & Associates Inc. 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 expire, unless evidence indicates that renewal is reasonably certain. 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. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data and well-test data.

Estimates of probable reserves, and the future cash flows related to such estimates, are inherently imprecise and are more uncertain than estimates of proved reserves and the future cash flows related to such estimates but have not been adjusted for risk due to such uncertainty. Because of such uncertainty, estimates of probable reserves, and the future cash flows related to such estimates, may not be comparable to estimates of proved reserves and the future cash flows related to such estimates and should not be summed arithmetically with estimates of proved reserves and the future cash flows related to such estimates. When producing an estimate of the amount of natural gas, NGLs and oil that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. All of our probable reserves as of June 30, 2023 were estimated using a deterministic method, which involves two distinct determinations: (i) an estimation of the quantities of recoverable oil and natural gas and (ii) an estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves uses the same generally accepted analytical procedures as are used in estimating proved reserves, namely production performance-based methods, material balance-based methods, volumetric-based methods and analogy. In the case of probable reserves, the recoverable reserves cannot be said to have a "high degree of confidence that the quantities will be recovered", but are "as likely as not to be recovered." The lower degree of certainty can come from several factors including: (1) direct offset production that does not meet an economic threshold, despite localized averages that do meet that threshold, (2) an increased distance from offset production to the probable location of over one mile but under three miles, (3) a perceived risk of communication or depletion from nearby producers, (4) a perceived risk of attempting new drilling or completion technologies that have not been used in direct offset production or (5) an uncertainty regarding geologic positioning that could affect recoverable reserves. When considering the factors referenced above, the lower degree of certainty of our probable reserves came from a combination of these factors. Many of the probable locations assigned in our reserve report as of June 30, 2023 had few uncertainties and resemble proved undeveloped locations except for their distance from commercial production. Other probable locations had uncertainties related to not only distance from commercial production, but also related to well spacing and development timing. In general, we did not book probable locations if there was geologic uncertainty or if there was not commercial production to support such locations.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable natural gas that cannot be measured in an exact manner. 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 natural gas that are ultimately recovered. Estimates of economically recoverable natural gas and of future net cash flows are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See “Risk Factors” appearing elsewhere in this prospectus.

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 — Reserve estimates depend on many assumptions that may turn out to 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 Paul Lupardus, our Executive Vice President — Engineering. Mr. Lupardus is primarily responsible for overseeing the preparation of our reserve estimates and has more than 38 years of experience as a reserve engineer. The reserves engineering group is independent of any of our operating areas. Mr. Lupardus 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 J. Zane Meekins, P.E., Executive Vice President at Cawley, Gillespie & Associates.

Mr. Meekins has been with Cawley, Gillespie & Associates since 1989 and graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins is a State of Texas registered professional engineer (License #71055) and a member of the Society of Petroleum Evaluation Engineers and the Society of Petroleum Engineers. Mr. Meekins 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. Meekins 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 23,438 MBbls of oil, and 9,978 MBbls of NGLs and 144,380 MMcf of natural gas for a total of 57,480 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 year ended December 31, 2022 (in MBoe):

Balance, December 31, 2021	27,891
Purchases of reserves	168
Revisions of previous estimates	37,468
Transfers to proved developed	(8,047)
Balance, December 31, 2022	57,480

Revisions of previous estimates of 37,468 MBoe during the year ended December31, 2022 included the addition of 256 PUDs (41,178 MBoe) based on increasing our drilling activity within proven areas of development, the deletion of 71 PUDs (-4,230 MBoe) due to five year development limitations and higher commodity prices (898 MBoe). Additionally, changes to reflect current market conditions on lease operating expenses and product price differentials totaled -378 MBoe.

We converted 8,047 MBoe of any PUDs into proved developed reserves in 2022. Costs incurred relating to the development of all oil and natural gas reserves were $279.3 million during the year ended December 31, 2022.

We drilled or participated in the drilling of 134 gross wells during 2022. We expect to drill or participate in the drilling of approximately 109 gross wells during 2023, and we expect to drill or participate in the drilling of approximately 116 gross wells during 2024.

All of our PUD drilling locations are scheduled to be drilled within five years of December 31, 2022. We expect to drill and complete or participate in the drilling and completion of approximately 109 PUD locations during 2023. We anticipate drilling and completing or participating in the drilling and completion of approximately 116 PUD locations during 2024, 115 during 2025, 73 during 2026 and 36 during 2027. These PUD locations relate to 57,480 MBoe of PUD reserves. Our development costs relating to the development of our PUDs at December 31, 2022 were expected to be approximately $283.0 million in 2023, and are projected to be $270.5 million in 2024, $198.0 million in 2025, $62.7 million in 2026 and $44.4 million in 2027 for a total of $858.6 million of future development costs. All of these PUD drilling locations are part of a development plan adopted by management. We expect that the substantial cash flow generated by our existing wells, in addition to availability under our New Credit Facility and the proceeds of this offering, 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 — Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.”

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Oil, Natural Gas and NGL Production Prices and Production Costs

Production and Price History

We currently only have production in the Anadarko Basin. The following table sets forth information regarding our production and operating data for the periods indicated.

Production data:

	Six Months Ended June 30,		Year Ended December 31,	
	2023	2022	2022	2021
Predecessor				
Oil sales (MBbl)	2,760	2,141	4,801	2,777
Natural gas sales (MMcf)	27,157	20,569	47,561	32,313
Natural gas liquids sales (MBbl)	1,373	1,322	2,812	2,180
Total (MBoe)	8,660	6,891	15,539	10,343
Total (MBoe/d)	47.84	38.07	42.57	28.34
BCE-Mach				
Oil sales (MBbl)	535	523	1,023	1,299
Natural gas sales (MMcf)	7,997	8,088	15,776	17,967
Natural gas liquids sales (MBbl)	464	502	969	1,131
Total (MBoe)	2,332	2,373	4,622	5,424
Total (MBoe/d)	12.88	13.11	12.66	14.86
BCE-Mach II				
Oil and condensate sales (MBbl)	75	76	158	160
Natural gas sales (MMcf)	3,521	3,711	7,610	6,965
Natural gas liquids sales (MBbl)	208	234	465	481
Total (MBoe)	870	929	1,891	1,802
Total (MBoe/d)	4.81	5.13	5.18	4.94
Total Pro Forma (MBoe)	11,861	10,193	22,053	17,568

Average realized sales prices:

	Six Months Ended June 30,		Year Ended December 31,	
	2023	2022	2022	2021
Predecessor				
Oil and condensate excluding effects of derivatives (per Bbl)	$ 75.46	$ 102.35	$ 93.43	$ 68.35
Natural gas excluding effects of derivatives (per Mcf)	$ 2.56	$ 6.32	$ 6.34	$ 4.08
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 25.29	$ 44.95	$ 39.27	$ 34.80
BCE-Mach				
Oil and condensate excluding effects of derivatives (per Bbl)	$ 72.68	$ 101.09	$ 94.54	$ 66.52
Natural gas excluding effects of derivatives (per Mcf)	$ 2.51	$ 5.75	$ 6.24	$ 3.40
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 25.43	$ 43.88	$ 39.65	$ 31.40
BCE-Mach II				
Oil and condensate excluding effects of derivatives (per Bbl)	$ 71.38	$ 99.77	$ 92.39	$ 63.78
Natural gas excluding effects of derivatives (per Mcf)	$ 1.98	$ 4.90	$ 5.35	$ 3.12
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 19.40	$ 38.73	$ 34.68	$ 26.80
Pro Forma ($/Boe)	$ 33.70	$ 55.40	$ 52.85	$ 35.60

Expense per Boe:

	Six Months Ended June 30,		Year Ended December 31,	
	2023	2022	2022	2021
Predecessor				
Gathering and processing expense	$ 2.02	$ 3.02	$ 3.06	$ 2.71
Lease operating expense	$ 7.00	$ 5.75	$ 6.17	$ 4.39
Production taxes (% of oil, natural gas and NGL sales)	5.0%	5.6%	5.6%	5.3%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 6.71	$ 4.26	$ 5.41	$ 3.63
Depreciation and amortization expense – other	$ 0.32	$ 0.29	$ 0.29	$ 0.30
General and administrative expense	$ 1.14	$ 1.98	$ 1.64	$ 5.89
BCE-Mach				
Gathering and processing expense	$ 5.97	$ 7.06	$ 7.45	$ 5.67
Lease operating expense	$ 8.80	$ 6.98	$ 7.70	$ 4.53
Production taxes (% of oil, natural gas and NGL sales)	5.2%	5.7%	5.7%	5.3%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 5.44	$ 5.40	$ 5.76	$ 4.97
Depreciation and amortization expense – other	$ 1.91	$ 1.73	$ 1.80	$ 1.43
General and administrative expense	$ 2.05	$ 1.12	$ 0.99	$ 1.92
BCE-Mach II				
Gathering and processing expense	$ 2.29	$ 2.98	$ 3.15	$ 2.10
Lease operating expense	$ 7.25	$ 6.63	$ 7.26	$ 5.97
Production taxes (% of oil, natural gas and NGL sales)	5.1%	5.6%	5.8%	5.1%
Depreciation, depletion, amortization and accretion expense – oil and natural gas	$ 2.49	$ 2.38	$ 2.37	$ 2.38
Depreciation and amortization expense – other	$ 0.40	$ 0.37	$ 0.36	$ 0.36
General and administrative expense	$ (1.77)	$ (1.45)	$ (1.35)	$ 0.41

Operating Data

The following table sets forth information regarding our pro forma revenues, net production volumes, average realized prices and operating expenses for the year ended December 31, 2022 and the six months ended June 30, 2023:

	Pro Forma Combined	
	Six Months Ended June 30, 2023	Year Ended December 31, 2022
	($ in thousands)	
Revenues:		
Oil	$ 252,537	$ 559,881
Natural gas	96,583	440,571
Natural gas liquids	50,566	164,968
Total oil, natural gas, and NGL sales	399,686	1,165,420
Gain (loss) on oil and natural gas derivatives, net	22,618	(113,322)
Total revenues	$ 422,304	$ 1,052,098
Average Sales Price[1]:		
Oil ($/Bbl)	$ 74.93	$ 93.60
Natural gas ($/Mcf)	$ 2.50	$ 6.21
NGL ($/Bbl)	$ 24.72	$ 38.85
Total ($/Boe) – before effects of realized derivatives	$ 33.70	$ 52.85
Total ($/Boe) – after effects of realized derivatives	$ 34.03	$ 45.27
Net Production Volumes:		
Oil (MBbl)	3,370	5,982
Natural gas (MMcf)	38,675	70,947
NGL (MBbl)	2,045	4,246
Total (MBoe)	11,861	22,053
Average daily total volumes (MBoe/d)	65.53	60.42

(1) Average sales prices exclude gathering and processing expense and the benefit of third party midstream revenues.

	Pro Forma Combined			
($ in thousands)	Six Months Ended June 30, 2023 ($)	Six Months Ended June 30, 2023 ($/Boe)	Year Ended December 31, 2022 ($)	Year Ended December 31, 2022 ($/Boe)
Operating Expenses:				
Gathering and processing expense	$ 33,430	$ 2.82	$ 87,887	$ 3.99
Lease operating expense	87,439	7.37	145,267	6.59
Midstream operating expense[1]	5,761	—	15,618	—
Cost of product sales[1]	15,575	—	94,580	—
Production taxes[1]	20,003	—	65,194	—
Depreciation, depletion, amortization and accretion expense – oil and natural gas	72,117	6.08	119,359	5.41
Depreciation and amortization expense – other	3,171	0.27	5,445	0.25
General and administrative	11,750	0.99	19,278	0.87

(1) $/Boe is not a useful metric for evaluating midstream operating expense, cost of product sales and production taxes.

Proved Developed Producing Wells

The following table sets forth information regarding our proved developed producing wells as of June 30, 2023:

	As of June 30, 2023 Proved Developed Producing Wells		Average Working Interest
	Gross	Net	
Combined Total:			
Natural gas	5,668	2,194	39%
Oil	3,861	1,729	45%
Total	9,529	3,923	41%

Developed and Undeveloped Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of June 30, 2023:

	Developed Acres	Undeveloped Acres	Total Acres
Gross	2,609,159	18,446	2,627,605
Net	922,808	12,760	935,568

Undeveloped acreage expirations

The following table sets forth the number of total net undeveloped acres as of June 30, 2023 that will expire in 2024, 2025, 2026 and 2027 unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed. This undeveloped acreage includes approximately 705 acres that PUD locations have been assigned to, however, within 2023, we have since drilled or scheduled drilling on nearly all of these acres.

	2023	2024	2025	2026
Total	1,457	2,058	6,964	1,541

All of our acreage is located in the Anadarko Basin.

Drilling Results

The table below sets forth the results of our operated drilling activities 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. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Six Months Ended June 30, 2023		Year Ended December 31, 2022		Year Ended December 31, 2021		Year Ended December 31, 2020	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells Operated:								
Productive	61	54	91	78	20	18	12	11
Dry holes	—	—	—	—	—	—	—	—
Total Development	61	54	91	78	20	18	12	11
Development Wells Non-Operated:								
Productive	14	3	14	2	1	—	1	—
Dry holes	—	—	—	—	—	—	—	—
Total Development	14	3	14	2	1	—	1	—
Exploratory Wells:								
Productive	—	—	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—	—	—
Total Development	—	—	—	—	—	—	—	—
Total Wells:								
Productive	75	57	105	80	21	18	13	11
Dry holes	—	—	—	—	—	—	—	—
Total Development	75	57	105	80	21	18	13	11

The following table sets forth information regarding our drilling activities as of June 30, 2023 and December 31, 2022, including with respect to our operated wells we have begun drilling and those which are drilled and awaiting completion.

	As of June 30, 2023		As of December 31, 2022	
	Gross	Net	Gross	Net
Drilling	3.0	2.8	6.0	5.1
Drilled and Completing	3.0	2.9	5.0	4.4

As of June 30, 2023, the Company was in process of drilling 3.0 gross wells (2.8 net), and had finished drilling and was completing or awaiting completion on 3.0 gross wells (2.9 net). Additionally, as of June 30, 2023, the Company had elected to participate in 14.0 non-operated gross wells (0.1 net) that were in process of drilling and completion.

As of December 31, 2022, the Company was in process of drilling 6.0 gross wells (5.1 net), and had finished drilling and was completing or awaiting completion on 5.0 gross wells (4.4 net). Additionally, as of December 31, 2022, the Company had elected to participate in 11.0 non-operated gross wells (2.3 net) that were in process of drilling and completion.

As of June 30, 2023, we were not a party to any long-term drilling rig contracts.

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Productive Wells

As of June 30, 2023, we owned interests in the following number of productive wells:

	Oil Wells	Gas Wells	Total
Predecessor			
Gross	2,047	3,412	5,459
Net	1,182	1,765	2,947
BCE-Mach			
Gross	1,553	478	2,031
Net	503	105	607
BCE-Mach II			
Gross	261	1,778	2,039
Net	44	324	368
Total			
Gross	3,861	5,668	9,529
Net	1,729	2,194	3,923

Marketing and Customers

We market production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices.

For the year ended December 31, 2022 and the six months ended June30, 2023, purchases by the following companies exceeded 10% of our predecessor's receipts from oil and gas sales:

	Year Ended December 31, 2022
Hinkle Oil and Gas Inc.	31.5%
NextEra Energy Marketing, LLC	17.0%
Phillips 66 Company	16.9%
Total	65.4%

	Six Months Ended June 30, 2023
Phillips 66 Company	52.0%
NextEra Energy Marketing, LLC	16.7%
Total	68.7%

For the year ended December 31, 2022 and the six months ended June30, 2023, purchases by the following companies exceeded 10% of BCE-Mach's receipts from oil and gas sales:

	Year Ended December 31, 2022
NextEra Energy Marketing, LLC	34.0%
Southwest Energy, LP	23.8%
ONEOK Hydrocarbon, L.P.	13.0%
Sandridge Energy, Inc.	11.9%
Coffeyville Resources, LLC	11.6%
Total	94.3%

	Six Months Ended June 30, 2023
Coffeyville Resources, LLC	40.5%
NextEra Energy Marketing, LLC	29.5%
Sandridge Energy, Inc.	11.4%
ONEOK Hydrocarbon, L.P.	10.3%
Total	91.7%

For the year ended December 31, 2022 and the six months ended June30, 2023, purchases by the following companies exceeded 10% of BCE-Mach II's receipts from oil and gas sales:

	Year Ended December 31, 2022
NextEra Energy Marketing, LLC	27.4%
ETC Field Services LLC	23.2%
Wheeler Midstream LLC	10.6%
Total	61.2%

	Six Months Ended June 30, 2023
ETC Field Services LLC	20.2%
NextEra Energy Marketing, LLC	16.0%
Wheeler Midstream LLC	13.7%
Enbridge Inc.	10.2%
Total	60.1%

Gathering & Processing Agreements and Firm Transportation

In some areas, we own our own gathering and/or processing assets but in other areas we incur gathering and processing expense under various gathering and/or processing agreements with third-party midstream providers. Only one of our gathering and/or processing agreements includes minimum volume commitments.

We are party to four firm transportation agreements to assist in transporting our natural gas from processing plants to various markets. Any unutilized capacity is monetized if market conditions allow by releasing the capacity to others or transporting third party gas. For the years ended December 31, 2022 and 2021, we incurred approximately $3.3 million and $2.9 million, respectively, of transportation charges under these agreements. For the six months ended June 30, 2023, we incurred approximately $1.8million of transportation charges under these agreements.

The following table sets forth certain information regarding certain of our firm transportation agreements:

	Midcontinent Express	Southern Star	OGT – Lincoln	OGT – Elmore City
Daily Quantity (MMBtu)	25,000	150,000	25,000	5,250
Average Rate (per MMBtu)	$ 0.33	$ 0.09	$ 0.17	$ 0.05
Expiration	July 31, 2024	January 1, 2025	May 31, 2024	October 31, 2023

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 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 or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. 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. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in evaluating and bidding for oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. 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 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 developing natural gas and may prevent or delay the commencement or continuation of a given operation. 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.

Seasonality of business

Generally, demand for natural gas, oil and NGL decreases during the spring and fall months and increases during the summer and winter months. However, certain natural gas and NGL markets utilize storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. In addition, seasonal anomalies such as mild winters or mild summers can have a significant impact on prices. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages, increased costs or delay operations.

Title to properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on 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 opinions 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 leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to 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 prospectus.

Legislative and regulatory environment

Our natural gas, oil and NGL exploration, development, production and related operations and activities are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with such rules and regulations can result in administrative, civil or criminal penalties, compulsory remediation and imposition of natural resource damages or other liabilities. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, we believe these obligations generally do not impact us differently or to any greater or lesser extent than they affect other operators in the natural gas and oil industry with similar operations and types, quantities and locations of production.

Regulation of production

In many states, oil and natural gas companies are generally required to obtain permits for drilling operations, provide drilling bonds, file reports concerning operations and meet other requirements related to the exploration, development and production of natural gas, oil and NGL. Such states also have statutes and regulations addressing conservation matters, including provisions for unitization or pooling of natural gas and oil interests, rights and properties, the surface use and restoration of properties upon which wells are drilled and disposal of water produced or used in the drilling and completion process. These regulations include the establishment of maximum rates of production from natural gas and oil wells, rules as to the spacing, plugging and abandoning of such wells, restrictions on venting or flaring natural gas and requirements regarding the ratability of production, as well as rules governing the surface use and restoration of properties upon which wells are drilled.

These laws and regulations may limit the amount of natural gas, oil and NGL that can be produced from wells in which we own an interest and may limit the number of wells, the locations in which wells can be drilled, or the method of drilling wells. Additionally, the procedures that must be followed under these laws and regulations may result in delays in obtaining permits and approvals necessary for our operations and therefore our expected timing of drilling, completion and production may be negatively impacted. These regulations apply to us directly as the operator of our leasehold. The failure to comply with these rules and regulations can result in substantial penalties.

Regulation of sales and transportation of liquids

Sales of condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress has enacted price controls in the past and could reenact such controls in the future.

Our sales of NGLs are affected by the availability, terms and cost of transportation. The transportation of NGLs in common carrier pipelines is subject to rate and access regulation. The Federal Energy Regulatory Commission ("FERC") regulates interstate oil, NGL and other liquid pipeline transportation rates under the Interstate Commerce Act. In general, interstate liquids pipeline rates are set using an annual indexing methodology, however, a pipeline may also use a cost-of-service approach, settlement rates or market-based rates in certain circumstances.

Intrastate liquids pipeline transportation rates 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. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of liquids transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of Natural Gas Policy Act of 1978 (the "NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 (“NGA”) and the NGPA, and by regulations and orders promulgated by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The Energy Policy Act of 2005 (the “EPAct of 2005”) amended the NGA and NGPA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EPAct of 2005 also provided FERC with the power to assess civil penalties of up to $1,000,000 per day (adjusted annually for inflation) for violations of the NGA and NGPA. As of 2023, the new adjusted maximum penalty amount is $1,496,035 per violation, per day. The civil penalty provisions are applicable to entities that engage in the sale and transportation of natural gas for resale in interstate commerce.

On January 19, 2006, FERC issued Order No. 670, implementing the anti-market manipulation provision of the EPAct of 2005, and subsequently denied rehearing. The resulting rules 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: (i) use or employ any device, scheme or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-FERC jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services. FERC also interprets its authority to reach otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704, described below. However, in October 2022, the Fifth Circuit ruled that FERC’s jurisdiction to regulate market manipulation is limited to interstate transactions only and does not reach intrastate natural gas transactions.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. As a result of these orders, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including oil and natural gas producers, gatherers and marketers, are now required to report, by May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance provided by FERC. Market participants must also indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC’s policy statement on price reporting.

Gathering service, which occurs upstream of jurisdictional transportation services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering facilities gathering function or a jurisdictional transportation function, FERC’s determinations as to the classification of facilities are done on a case-by-case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transportation facilities as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of getting gas to point of sale locations may increase. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transportation services and federally unregulated gathering services could be the subject of ongoing litigation, so the classification and regulation of our gathering facilities could be subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

In addition, the pipelines in the gathering systems on which we rely may be subject to regulation by the U.S. Department of Transportation. The Pipeline and Hazardous Materials Safety Administration (“PHMSA”) has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. Over the past several years PHMSA has taken steps to expand the regulation of rural gathering lines and impose a number of reporting and inspection requirements on regulated pipelines, and additional requirements are expected in the future. On November 15, 2021, PHMSA released a final rule that expands the definition of regulated gathering pipelines and imposes safety measures on certain currently unregulated gathering pipelines. The final rule also imposes reporting requirements on all gathering pipelines and specifically requires operators to report safety information to PHMSA. The future adoption of laws or regulations that apply more comprehensive or stringent safety standards could increase the expenses we incur for gathering service.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical and financial sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC under the EPAct of 2005 and by the Commodity Futures Trading Commission ("CFTC") under the Commodity Exchange Act ("CEA") as amended by the Dodd-Frank Wall Street Reform and Consumer Protection Act, and regulations promulgated thereunder. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity as well as certain disruptive trading practices. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. As such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC, PHMSA, the CFTC, or state policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC, PHMSA, the CFTC, or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other oil and natural gas producers and marketers with which we compete.

Regulation of environmental and occupational safety and health matters generally

Our operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing environmental protection, occupational safety and health, and the release, discharge or disposal of materials into the environment, some of which carry substantial administrative, civil and criminal penalties for failure to comply. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), the CWA and the CAA. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the prevention and cleanup of pollutants, and other matters. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling, and production operations; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit construction or drilling activities in sensitive areas such as wilderness, wetlands, frontier and other protected areas; require investigatory or remedial actions to prevent or mitigate pollution conditions caused by our operations; impose obligations to reclaim and abandon well sites and pits; establish specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties, loss of leases, the imposition of investigatory or remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas. 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 gas industry increases the cost of doing business in the industry and consequently affects profitability. It is possible that, over time, environmental regulation could evolve to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or reinterpretation 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 require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations and financial position. 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 be sure 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. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our business, there can be no assurance that this will continue in the future.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are 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

CERCLA, also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These classes of persons, or, as termed in CERCLA, potentially responsible parties, include the current and past owners or operators of a disposal site or site where the release occurred and anyone who disposed or arranged for the disposal of the hazardous substances found at such sites. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances under CERCLA and other environmental laws but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect our business operations. While petroleum and crude oil fractions are generally not considered hazardous substances under CERCLA and its analogues because of the so-called "petroleum exclusion," adulterated petroleum products containing other hazardous substances have been treated as hazardous substances in the past.

We also generate solid and hazardous wastes that may be subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and analogous state laws. RCRA regulates the generation, handling, storage, treatment, transport and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes "drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy" from regulation as hazardous wastes. With the approval of the EPA, individual states can administer some or all of the provisions of RCRA and some states have adopted their own, more stringent requirements. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent handling, disposal and clean-up requirements. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes are determined to have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease or operate numerous properties that may have been used by prior owners or operators for oil and natural gas development and production activities 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 off-site locations where such substances have been taken for recycling or disposal. In addition, some of our properties may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and/or 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.

Water discharges

The Federal Water Pollution Control Act, also known as the CWA, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including spills and leaks of oil and other natural gas wastes, into or near waters of the United States or state waters. 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. The discharge of dredge and fill material into regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the “Corps”). The EPA and the Corps issued a final rule on the federal jurisdictional reach over waters of the United States in 2015, which never took effect before being replaced by the Navigable Waters Protection Rule (the “NWPR”) in December 2019. A coalition of states and cities, environmental groups, and agricultural groups challenged the NWPR, which was vacated by a federal district court in August 2021. The EPA is undergoing a two-phase rulemaking process to attempt to redefine the definition of waters of the United States. A final rule, known as “Rule 1” was announced by the EPA and the Corps in December 2022. The EPA and Corps are expected to propose a second rule, known as “Rule 2”, further refining Rule 1 by November 2023 and issue a final rule by July 2024. However, EPA’s rulemaking process could be impacted by the U.S. Supreme Court’s recent decision in Sackett v. EPA, which invalidated the test used by the EPA to determine whether wetlands qualify as navigable waters of the United States. To the extent a stay of recent rules or the implementation of a revised rule expands the scope of the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits, including for dredge and fill activities in wetland areas.

The process for obtaining permits also has the potential to delay our operations. For example, in April 2020, the U.S. District Court for the District of Montana vacated Nationwide Permit (“NWP”) 12, the general permit issued by the Corps for pipelines and utility projects. On May 11, 2020, the court narrowed its ruling, vacating and enjoining the use of NWP 12 only as it relates to construction of new oil and gas pipelines. The Corps appealed the decision to the U.S. Court of Appeals for the Ninth Circuit. On July 6, 2020, the U.S. Supreme Court granted in part and denied in part the Corps’ application for stay of the order issued by the district court. The U.S. Supreme Court stayed the lower court order except as it applies to the Keystone XL pipeline. On January 5, 2021, the Corps released the final version of a rule renewing twelve of its NWPs, including NWP 12. The new rule, which took effect on March 15, 2021, splits NWP 12 into three parts; NWP 12 will continue to be available to oil and gas pipelines. On March 28, 2022, the Corps published a notice announcing that it is undertaking formal review of NWP 12 and sought public comments. The comment period ended on through May 27, 2022 and the review remains pending. Any further changes to NWP 12 could have an impact on our business. We cannot predict at this time how the new Corps rule will be implemented, because permits are issued by the local Corps district offices. If new oil and gas pipeline projects are unable to utilize NWP 12 or identify an alternate means of CWA compliance, such projects could be significantly delayed. Additionally, spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” are required by federal law in connection with on-site storage of significant quantities of oil. Compliance may require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak.

Safe Drinking Water Act

The SDWA grants the EPA broad authority to take action to protect public health when an underground source of drinking water is threatened with pollution that presents an imminent and substantial endangerment to humans. The SDWA also regulates saltwater disposal wells under the Underground Injection Control Program. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of “underground injection,” but disposal of hydraulic fracturing fluids and produced water or their injection for enhanced oil recovery is not excluded. In 2014, the EPA issued permitting guidance governing hydraulic fracturing with diesel fuels. While we do not currently use diesel fuels in our hydraulic fracturing fluids, we may become subject to federal permitting under SDWA if our fracturing formula changes.

Air emissions

The CAA and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and other requirements. 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. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (“NAAQS”) for ozone from 75 to 70 parts per billion. In December 2020, the EPA announced its intention to leave the ozone NAAQS unchanged at 70 parts per billion. Further, in June 2016, the EPA also finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. These rules could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements.

State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the EPA has adopted new rules under the CAA that require the reduction of volatile organic compound (“VOC”) and methane emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most 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. In addition, the regulations place new requirements to detect and repair volatile organic compound and methane at certain well sites and compressor stations. On November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule imposes emissions reduction standards on both new and existing sources in the oil and natural gas industry, expands the scope of CAA regulation, and imposes emissions reductions targets to meet the stated goals of the U.S. federal administration. On November 11, 2022, the EPA issued the proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as “super emitters.” The EPA is currently expected to issue a final rule by August 2023. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas projects and increase our costs of development, which costs could be significant.

Climate change

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply with such laws and regulations. These requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. The EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations.

On November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule imposes emissions reduction standards on both new and existing sources in the oil and natural gas industry, expands the scope of CAA regulation, and imposes emissions reductions targets to meet the stated goals of the U.S. federal administration. On November 11, 2022, the EPA issued the proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as “super emitters.” The EPA is currently expected to issue a final rule by August 2023. We cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility. There are also a number of state and regional efforts to regulate emissions of methane from new and existing sources within the oil and natural gas source category. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment, and increased frequency of maintenance and repair activities to address emissions leakage at certain well sites and compressor stations, and also may require hiring additional personnel to support these activities or the engagement of third-party contractors to assist with and verify compliance.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and the current U.S. presidential administration has taken and supported action aiming to limit GHG emissions. At the international level, in April 2016, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, which resulted in an agreement intended to nationally determine their contributions and set GHG emission reduction goals every five years beginning in 2020. In November 2019, plans were formally announced for the U.S. to withdraw from the Paris Agreement with an effective exit date in November 2020. In February 2021, the current administration announced reentry of the U.S. into the Paris Agreement along with a new "nationally determined contribution" for U.S. GHG emissions that would achieve emissions reductions of at least 50% relative to 2005 levels by 2030. In August 2022, President Biden signed the Inflation Reduction Act into law, which focuses on incentivizing the reduction of methane emissions and would impose a fee on methane produced by petroleum and natural gas facilities in excess of a specified threshold, among other initiatives.

Separately, many U.S. state and local leaders and foreign governments have intensified or stated their intent to intensify efforts to support international climate commitments and treaties and have developed programs that are aimed at reducing GHG emissions, such as by means of cap and trade programs, carbon taxes, encouraging the use of renewable energy or alternative low-carbon fuels, or imposing new climate-related reporting requirements. Cap and trade programs, for example, typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

Financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. President Biden signed an executive order calling for the development of a "climate finance plan" and, separately, the Federal Reserve in 2020 announced that it joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. In 2022, the Federal Reserve launched a pilot climate scenario analysis exercise to learn about certain large banking organizations' climate risk-management practices and challenges and help ensure that supervised institutions are appropriately managing material financial risks related to climate change. Limitation of investments in and financing for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Additionally, on March 21, 2022, the SEC issued a proposed rule regarding the enhancement and standardization of mandatory climate-related disclosures for investors. The proposed rule would require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including, but not limited to, information about the registrant's governance of climate-related risks and relevant risk management processes; climate-related risks that are reasonably likely to have a material impact on the registrant's business, results of operations, or financial condition and their actual and likely climate-related impacts on the registrant's business strategy, model, and outlook; climate-related targets, goals and transition plan (if any); certain climate-related financial statement metrics in a note to their audited financial statements; Scope 1 and Scope 2 GHG emissions; and Scope 3 GHG emissions and intensity, if material, or if the registrant has set a GHG emissions reduction target, goal or plan that includes Scope 3 GHG emissions. The proposed rule's ultimate date of effectiveness and the final form and substance of these requirements is not yet known. Regulations requiring the disclosure of similar climate-related information have also been proposed at the state-level, including in California.

Any legislation or regulatory programs aimed at reducing GHG emissions, addressing climate change more generally, or requiring the disclosure of climate-related information could increase the cost of consuming, and thereby reduce demand for, the natural gas we produce or otherwise have an adverse effect on our business, financial condition and results of operations.

Hydraulic fracturing

Hydraulic fracturing is a common practice that is used to stimulate production of oil and/or natural gas from low permeability subsurface rock formations and is important to our business. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the hydrocarbon-bearing rock formation and stimulate production of hydrocarbons. We regularly use hydraulic fracturing as part of our operations. Presently, hydraulic fracturing is primarily regulated at the state level, typically by state natural gas commissions, but the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. In June 2016, the EPA issued additional New Source Performance Standards rules, known as Subpart OOOOa, focused on achieving additional methane and volatile organic compound reductions from new and modified oil and natural gas production and natural gas processing and transmission facilities. Among other things, these revisions imposed new requirements for leak detection and repair, control requirements for oil well completions, and additional control requirements for gathering, boosting, and compressor stations. In September 2020, the EPA finalized two sets of amendments to the 2016 OOOOa standards. The first, known as the “2020 Technical Rule” reduced the 2016 rule’s fugitive emissions monitoring requirements and expended exceptions to pneumatic pump requirements, among other changes. The second, known as the “2020 Policy Rule” rescinded the methane specific requirements for certain oil, NGL and natural gas sources in the production and processing segments.

In addition, there are heightened concerns by the public about hydraulic fracturing causing damage to aquifers and there is potential for future regulation to address those concerns. 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 certain activities associated with hydraulic fracturing may impact drinking water resources under some circumstances.

At the state level, several states have adopted or are considering legal requirements that require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. Local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and attendant permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential legislation or regulation governing hydraulic fracturing, and any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Oil Pollution Act

The Oil Pollution Act of 1990 (the “OPA”) establishes strict liability for owners and operators of facilities that are the source of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties, including owners and operators of certain facilities from which oil is released, related to the prevention of oil spills and liability for damages resulting from such spills. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of an environmental assessment and, if necessary, an environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action have the potential to significantly impact the environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, may increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases. On July 16, 2020, the Council on Environmental Quality ("CEQ") revised NEPA's implementing regulations to make the NEPA process more efficient, effective and timely. The rule required federal agencies to develop procedures consistent with the new rule within one year of the rule's effective date (which was extended to two years in June 2021). These regulations are subject to ongoing litigation in several federal district courts, and in October 2021, CEQ issued a notice of proposed rulemaking to amend the NEPA regulatory changes adopted in 2020 in two phases. Phase I of the CEQ's rulemaking process was finalized on April 20, 2022, and generally restored provisions that were in effect prior to 2020. CEQ sent its Phase II proposal to the Office of Management and Budget on January 7, 2023. The Phase II proposal is expected to be published in 2023. However, several states and environmental groups have filed challenges to this rulemaking, and CEQ's amendments are subject to reconsideration and may be subject to reversal or change under the Biden administration. Further, the Infrastructure and Investment Jobs Act, Pub.L. 117-58, signed into law in November 2021, codified some of the July 2020 amendments in statutory text. These amendments must be implemented into each agency's implementing regulations, and each of those individual rulemakings could be subject to legal challenge. The impact of changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our operations and our ability to obtain governmental permits.

Endangered Species Act and Migratory Bird Treaty Act

The ESA restricts activities that may affect endangered or threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"). We may conduct operations on natural gas leases in areas where certain species that are or could be listed as threatened or endangered are known to exist. In February 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for natural gas development. The Trump administration issued rules that narrowed the definition of "habitat" and altered a policy in a way that made it easier to exclude territory from critical habitat. In October 2021, the Biden administration published two rules that reversed those changes, and in June and July 2022, the FWS issued final rules rescinding Trump-era regulations concerning the definition of "habitat" and critical habitat exclusions. The designation of previously unprotected species as threatened or endangered or new critical or suitable habitat designations in areas where we conduct operations could result in limitations or prohibitions on our operations and could adversely impact our business, and it is possible the new rules could increase the portion of our lease areas that could be designated as critical habitat. It is possible the October 2021 rules could increase the portion of our lease areas that could be designated as critical habitat. 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.

The Department of the Interior also issued an opinion in December 2017 that would narrow certain protections afforded to migratory birds pursuant to the MBTA. The MBTA makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit, and concurrently finalized a rule limiting application of the MBTA. The Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment to the Department of the Interior's plan to develop regulations that authorize incidental take under certain prescribed conditions. The notice of proposed rulemaking was expected in March 2023, though it has not been published yet, and is expected to be finalized by the end of 2023. 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 or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. 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.

Worker health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. For example, 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 maintain, 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. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

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 oil and 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 contamination risks associated with our development activities, including a coverage policy for gradual pollution events. However, this insurance is limited to activities at the well site and 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

We aim to provide a safe, healthy, respectful, and fair workplace for all employees. We believe our employees' talent and wellbeing is foundational to delivering on our corporate strategy, and that intentional human capital management strategies enable us to attract, develop, retain and reward our dedicated employees.

As of December 31, 2022, Mach Resources had 399 total employees, 397 of which were full-time employees. From time to time, we utilize the services of independent contractors to perform various field and other services. Neither we nor Mach Resources are 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.

Employee Safety and Health

The health, safety, and well-being or our employees is a top priority. In addition to our commitment to complying with all applicable safety, health, and environmental laws and regulations, we are focused on minimizing the risk of workplace incidents and preparing for emergencies as a priority element of our culture. We work to reduce safety incidents in our business and actively seek opportunities to make safety culture and procedural improvements.

Legal proceedings

The Company may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of business. The Company is not currently a party to any material legal proceedings. In addition, the Company is not aware of any material legal proceedings contemplated to be brought against the Company.

The Company, as an owner and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution cleanup resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage that is customary in the industry, although the Company is not fully insured against all environmental risks.

The Company is not aware of any environmental claims existing as of June 30, 2023. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered on the Company s oil and gas properties.

MANAGEMENT

Management of Mach Natural Resources

We are managed and operated by our general partner, which is managed by the Board and executive officers of our general partner. The members of our general partner are BCE-Mach Aggregator, which is controlled by our Sponsor, and certain members of management. All of our independent directors will be appointed prior to the date our common units are listed for trading on the NYSE. Our unitholders will not be 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.

Upon the closing of this offering, we expect that our general partner will have five directors, each of whom will be appointed by the Sponsor and certain members of management, as the members of our general partner. The NYSE does not require a listed publicly traded limited 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 this offering. We will have at least independent members of the audit committee by the date our common units first trade on the NYSE.

Our operations will be conducted through, and our assets will be owned by, various subsidiaries. However, we will 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, such as pursuant to the MSA, but we sometimes refer to these individuals, for drafting convenience only, in this prospectus as our employees because they provide services directly to us.

Following the consummation of this offering, neither our general partner nor the Sponsor 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, including Mach Resources, 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. Please read "Certain Relationships and Related Party Transactions."

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.

Executive Officers and Directors of Our General Partner

The following table sets forth certain information regarding the current executive officers and directors of our general partner upon consummation of this offering.

Name	Age	Position
Tom L. Ward	64	Chief Executive Officer and Director
Kevin R. White	66	Chief Financial Officer
Daniel T. Reineke, Jr.	40	Executive Vice President, Business Development
Michael E. Reel	37	General Counsel
William McMullen	38	Chairman of the Board
		Director
		Director
		Director

Tom L. Ward — Chief Executive Officer and Director. Mr. Ward has served as our Chief Executive Officer since our founding in 2017. Prior to joining the Company, he served as Chairman and Chief Executive Officer of Tapstone Energy from 2013 to 2017 and Sandridge Energy (NYSE: SD) from 2006 to 2013. Prior to joining SandRidge Energy, he served as President, Chief Operating Officer and a director of Chesapeake Energy Corporation (NYSE: CHK) from the time he co-founded the company in 1989 until February 2006. Mr. Ward graduated from the University of Oklahoma in 1981 with a Bachelor of Business Administration in Petroleum Land Management.

We believe that Mr. Ward's extensive industry background, his previous experience as a director and executive of public companies, and deep knowledge of our business as founder make him well suited to serve as a member of our board of directors.

Kevin R. White — Chief Financial Officer. Mr. White has served as our Chief Financial Officer since March 2017. Prior to joining the Company, he served as Chief Financial Officer of Petroflow Energy Corporation from June 2016 to March 2017 and as SVP — Business Development and Investor Relations of SandRidge Energy from January 2008 to September 2013. Mr. White served as Executive Vice President of Corporate Development and Strategic Planning for Louis Dreyfus Natural Gas Corp. from 1993 until the company was sold in 2001. He attended Oklahoma State University, receiving his Bachelor of Science degree in Accounting in 1979 and a Master of Science degree in Accounting and his Certified Public Accountant qualification in 1980.

Daniel T. Reineke, Jr. — Executive Vice President, Business Development. Mr. Reineke has served as Executive Vice President, Business Development since our founding in 2017. Prior to joining the Company, he served as Chief Investment Officer for TLW Trading since 2013. Prior to his time with TLW Trading, Mr. Reineke served as a Vice President at RBC Wealth Management, Vice President/General Counsel for Stampede Farms, and Associate General Counsel at Gulfport Energy Corporation (NYSE: GPOR). Mr. Reineke graduated from the University of Oklahoma School of Law receiving his Juris Doctorate in 2007 after receiving his Bachelor of Business Administration in Finance in 2004 from the University of Oklahoma.

Michael E. Reel — General Counsel. Mr. Reel joined the Company in July 2017 and currently serves as General Counsel. Prior to joining the Company, he served as Senior Counsel for Accelerate Resources. Prior to his time at Accelerate Resources, Mr. Reel served as internal counsel for White Star Petroleum, LLC, American Energy Partners, LP and Chesapeake Energy Corporation. Mr. Reel graduated from Oklahoma State University in 2008 with a Bachelor of Science degree in Political Science and received his Juris Doctorate from Oklahoma City University School of Law in 2011.

William W. McMullen — Chairman of the Board. Mr. McMullen has served as Founder and Managing Partner of BCE since 2015, leading the firm's investment strategy and capital allocation decisions. Prior to founding BCE in 2015, Mr. McMullen worked at White Deer Energy from 2012 to 2014. Previously, Mr. McMullen worked at Denham Capital Management from 2010 to 2012 and UBS Investment Bank's Global Energy Group from 2008 to 2010. Mr. McMullen earned his AB in Economics, with Honors, from Harvard University.

We believe that Mr. McMullen'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.

Reimbursement of Expenses of Our General Partner

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

Board of Directors

Prior to the date that our common units are first traded on the NYSE, we expect our general partner to have a -member board of directors.

In evaluating director candidates, the members of our general partner 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

Our independent directors will meet the independence standards established by the NYSE listing rules.

Committees of the Board of Directors

The Board will have 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 will assist 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 will have 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 will also be 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. Effective upon the consummation of this offering, , and will serve on the audit committee. will serve as chair of the audit committee.

Conflicts Committee

In accordance with the terms of our partnership agreement, at least 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. We expect that , and will serve as members of our conflicts committee. Please read "Conflicts of Interest and Duties."

Compensation Committee

Effective upon the consummation of this offering, the members of our compensation committee will be , and , who will also serve as chair of the compensation committee. Each of the members of our compensation committee will be independent under the applicable rules and regulations of the NYSE, will be a "non-employee director" as defined in Rule 16b-3 promulgated under the Exchange Act and will be an "outside director" as that term is defined in Section 162(m) of the Code (Section 162(m)). The compensation committee will operate under a written charter that satisfies the applicable standards of the SEC and the NYSE.

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.

Board Leadership Structure

Leadership of our general partner's board of directors is vested in a Chairman of the Board. Mr. William McMullen will serve as a Director and the Chairman of the Board. 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. Directors of the Board are designated or elected by the Sponsor and certain members of management as the members of our general partner. Accordingly, unlike holders of common stock in a corporation, our unitholders will have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Board Role in Risk Oversight

Our corporate governance guidelines will 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 will be 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.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

General

We do not directly employ directors, officers or employees; instead, all of the employees that conduct our business are either employed by Mach Resources or its subsidiaries. We depend on Mach Resources and such employees to provide us and our general partner with services necessary to operate our business. In connection with this offering, the Company will enter into the MSA under which Mach Resources will manage and perform all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, we will reimburse our general partner and its affiliates for certain expenses they incur and payments they make on our behalf pursuant to the MSA. 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, 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. The reimbursement of expenses to our general partner and its affiliates will reduce the amount of cash available for distribution to our unitholders. During the year ended December 31, 2022, we paid $67.0 million to Mach Resources, which consists of $3.4 million for an annual management fee and $63.6 million for reimbursements of its costs and expenses under the existing management services agreements among Mach Resources and the Mach Companies (the "Existing MSAs").

For a description of our other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions." Although all of the employees that conduct our business are employed by Mach Resources, we sometimes refer to these individuals in this prospectus as our employees.

Emerging Growth Company Status

We are currently considered an "emerging growth company," within the meaning of the Securities Act, for purposes of the SEC's executive compensation disclosure rules. In accordance with these rules, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures regarding executive compensation for our last completed fiscal year. Furthermore, our reporting obligations extend only to our "named executive officers," who are the individuals who served as our principal executive officer during 2022 and our next two most highly compensated executive officers at the end of 2022. Accordingly, our "Named Executive Officers" for 2022 are:

Name	Principal Position
Tom L. Ward	Chief Executive Officer
Kevin R. White	Chief Financial Officer
Daniel T Reineke, Jr.	Executive Vice President — Business Development

This discussion may contain forward-looking statements that are based on our current plans, considerations, expectations and determinations regarding future compensation programs. Actual compensation programs that we adopt in the future may differ materially from the currently planned programs summarized in this discussion.

2022 Summary Compensation Table

The following table summarizes the compensation awarded to, earned by or paid to our Named Executive Officers for the fiscal year ended December 31, 2022.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	All Other Compensation ($)(2)	Total ($)
Tom L. Ward *Chief Executive Officer*	2022	600,000	—	27,000	627,000
Kevin R. White *Chief Financial Officer*	2022	475,000	47,500	27,000	549,500
Daniel T. Reineke, Jr *Executive Vice President, Business Development*	2022	660,960	66,096	20,500	747,556

(1) The amounts in this column represent discretionary short-term cash incentive awards paid for 2022. Bonus amounts were determined as more specifically discussed under "Narrative Disclosure to Summary Compensation Table — Annual Bonuses."

(2) The amounts in this column reflect the Company's matching contributions to the Company's 401(k) plan for the Named Executive Officers.

Narrative Disclosure to Summary Compensation Table

No Employment Agreements and/or Offer Letters

We have not entered into any employment agreement, offer letter or similar employment contract with any of our Named Executive Officers.

Base Salary

Each Named Executive Officer's base salary is a fixed component of compensation for performing specific job duties and functions. Base salaries are generally set at levels deemed necessary to attract and retain individuals with superior talent commensurate with their relative expertise and experience.

Annual Bonuses

Annual cash bonuses are used to motivate and reward our executives and other employees. The annual bonuses paid to our Named Executive Officers (other than Mr. Ward) for the 2022 fiscal year were discretionary bonuses ultimately determined by Mr. Ward and not linked to any performance metrics of the Company or otherwise. Mr. Ward historically has not been considered for annual bonuses and, accordingly, Mr. Ward did not receive an annual bonus in 2022. The target annual bonus opportunity for each of Messrs. White and Reineke is not memorialized in any written plan or other document but has historically been approximately 10% of their base salaries. For 2022, the payments of annual bonuses for Messrs. White and Reineke were divided into two installments, with half of the bonuses becoming payable in July 2022 and the remaining half becoming payable in January 2023.

Equity Incentives

In connection with the formation of each of the Mach Companies, each of our Named Executive Officers received one-time awards of Mach Company Class B Units. The Mach Companies Class B Units are equity incentive awards intended to qualify as "profits interests" for U.S. federal income tax purposes. The Mach Companies Class B Units held by our Named Executive Officers are subject to service-based vesting requirements and are described in more detail in the footnotes to the "Outstanding Equity Awards at 2022 Fiscal Year-End" table below.

For more details regarding the treatment of the Mach Companies Class B Units upon certain terminations of employment, including in connection with a change in control of the Company, please see the section entitled "— Additional Narrative Disclosure — Potential Payments Upon Termination or Change in Control" below.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth information regarding all outstanding equity incentive awards held by each of our Named Executive Officers as of December 31, 2022.

	Option Awards[1]				
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price ($)[2]	Option Expiration Date[2]
Tom L. Ward	3/29/2018	16,000[3]	—	N/A	N/A
	3/25/2021	12,000[4]	6,000[4]	N/A	N/A
	3/25/2021	12,000[5]	6,000[5]	N/A	N/A
Kevin R. White	3/29/2018	1,000[6]	—	N/A	N/A
	3/25/2021	606.7[7]	303.3[7]	N/A	N/A
	3/25/2021	606.7[8]	303.3[8]	N/A	N/A

	Option Awards[1]				
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price ($)[2]	Option Expiration Date[2]
Daniel T. Reineke, Jr.	3/29/2018	1,000[6]	—	N/A	N/A
	3/25/2021	606.7[7]	303.3[7]	N/A	N/A
	3/25/2021	606.7[8]	303.3[8]	N/A	N/A

(1) All awards in this table consist of Mach Companies Class B Units representing membership interests in the Mach Companies that are intended to constitute profits interests for federal income tax purposes. These awards are not traditional options, and therefore, there is no exercise price or expiration date associated with them. Despite Mach Companies Class B Units not requiring the payment of an exercise price, they are most similar economically to stock options. The awards in this table are rounded to the nearest tenth.

(2) The Mach Companies Class B Units are not traditional options; therefore, there is no exercise price or option expiration date associated therewith.

(3) 16,000 Class B Units of BCE-Mach were granted to Mr. Ward on March 29, 2018, all of which were vested as of December 31, 2022.

(4) 18,000 Class B Units of BCE-Mach II were granted to Mr. Ward on March 25, 2021, of which 9,000 Class B Units were immediately vested as of the grant date and the remainder are scheduled to vest in equal, annual installments on January 1 of the first three calendar years following the grant date, subject to Mr. Ward's continued service through the applicable vesting date, such that 3,000 Class B Units vested on each of January 1, 2022 and January 1, 2023, and the remaining 3,000 Class B Units will vest on January 1, 2024, subject to Mr. Ward's continued service through the vesting date.

(5) 18,000 Class B Units of BCE-Mach III were granted to Mr. Ward on March 25, 2021, of which 9,000 Class B Units were immediately vested as of the grant date and the remainder are scheduled to vest in equal, annual installments on January 1 of the first three calendar years following the grant date, subject to Mr. Ward's continued service through the applicable vesting date, such that 3,000 Class B Units vested on each of January 1, 2022 and January 1, 2023, and the remaining 3,000 Class B Units will vest on January 1, 2024, subject to Mr. Ward's continued service through the vesting date.

(6) 1,000 Class B Units of BCE-Mach were granted to each of Messrs. White and Reineke on March 29, 2018, all of which were vested as of December 31, 2022.

(7) 910 Class B Units of BCE-Mach II were granted to each of Messrs. White and Reineke on March 25, 2021, of which 303.3 Class B Units were immediately vested as of the grant date and the remainder are scheduled to vest in equal, annual installments on January 1 of the first two calendar years following the grant date, subject to continued service through the applicable vesting date, such that 303.3 Class B Units vested on each of January 1, 2022 and January 1, 2023. As of the date of this prospectus, all of these Class B Units are fully vested.

(8) 910 Class B Units of BCE-Mach III were granted to each of Messrs. White and Reineke on March 25, 2021, of which 303.3 Class B Units were immediately vested as of the grant date and the remainder are scheduled to vest in equal, annual installments on January 1 of the first two calendar years following the grant date, subject to continued service through the applicable vesting date, such that 303.3 Class B Units vested on each of January 1, 2022 and January 1, 2023. As of the date of this prospectus, all of these Class B Units are fully vested.

Additional Narrative Disclosure

Retirement Benefits

We do not have a defined benefit pension plan or nonqualified deferred compensation plan. We currently maintain a retirement plan intended to provide benefits under Section 401(k) of the Code, pursuant to which employees, including the Named Executive Officers, can make voluntary pre-tax contributions. We match 100% of elective deferrals up to 10% of salary for our Named Executive Officers. Our employer matching contributions vest in equal, annual installments on the first four anniversaries of a participant's commencement of service, and our Named Executive Officers are 100% vested in employer matching contributions. All contributions under the retirement plan are subject to certain annual dollar limitations, which are periodically adjusted for changes in the cost of living.

Potential Payments Upon Termination or Change in Control

Under the applicable equity agreements between each of the Named Executive Officers and the Mach Companies, if a Named Executive Officer's employment is terminated due to his death or disability, then the next tranche of unvested Mach Companies Class B Units, as applicable, held by the Named Executive Officer scheduled to vest on the next vesting date following the termination date will immediately vest as of the termination date. In addition, each Named Executive Officer's unvested Mach Companies Class B Units of the Mach Companies will become fully vested immediately prior to a "Change of Control" (as defined in the applicable operating agreement of the Mach Companies and including an initial public offering), subject to the Named Executive Officer's continued employment through the Change of Control. Accordingly, in connection with the completion of this offering, any unvested Mach Company Class B Units held by the Named Executive Officers are expected to fully vest immediately prior to the consummation of the offering. As described in the footnotes to the "Outstanding Equity Awards at Fiscal Year-End" table above, all of the Class B Units of BCE-Mach held by the Named Executive Officers, and the Class B Units of BCE-Mach II and BCE-Mach III held by Messrs. White and Reineke, were fully vested as of January 1, 2023.

Non-competition Payments

Under the operating agreements of the Mach Companies, if, as of December 31, 2022, (a) Mr. Ward's employment was terminated without "Cause" or for "Good Reason" or (b) any of the Existing MSAs were terminated (subject to limited exceptions), the Company could have extended Mr. Ward's post-termination non-competition and non-solicitation period so long as the Company continued to pay Mr. Ward his annualized compensation (including cash and the value of any equity grants) for the year preceding his (or the applicable Existing MSA's) termination, not to exceed 12 months following the termination. If Mr. Ward's employment (or an Existing MSA) was terminated for any other reason, then Mr. Ward's post-termination non-competition and non-solicitation period would have lasted for six months following such termination without any severance or other consideration required to be paid.

"Cause" is generally defined to mean (subject to customary notice and cure provisions for clauses (iv) and (v)): (i) conviction of, or plea of guilty or *nolo contendere* to, any felony or any crime involving theft, embezzlement, dishonesty or moral turpitude; (ii) any act constituting theft, embezzlement, fraud or similar conduct in the performance of the employee's duties; (iii) any act constituting willful misconduct, deliberate malfeasance, or gross negligence in the performance of the employee's duties; (iv) willful and continued failure to perform any of the employee's duties; or (v) any material breach by the employee of the applicable operating agreement or any other agreement between the employee and the Company.

"Good Reason" is generally defined to mean (subject to customary notice and cure provisions for clauses (i), (ii) and (iii)): (i) a material diminution in title, position or duties; (ii) relocation of the employee's primary office location by more than 50 miles; (iii) any material breach by the Company of any agreement with the employee; (iv) a termination of any of the Existing MSAs pursuant to certain sections thereunder; or (v) any reduction by the Company in any component of the employee's compensation, unless mutually agreed.

Other Restrictive Covenants

Under their equity agreements, Messrs. White and Reineke are subject to non-competition and non-solicitation covenants while they are employees of Mach Resources and providing services to the Company.

Long-Term Incentive Plan

In order to incentivize our employees following the completion of this offering, we anticipate that our general partner will adopt a new long-term incentive plan (the "Long-Term Incentive Plan") for employees, consultants and directors in connection with this offering. Our directors, officers, employees, consultants, and other individual service providers (including our Named Executive Officers) will be eligible to participate in the Long-Term Incentive Plan, which we expect will become effective upon the consummation of this offering. We currently expect that the board of directors of our general partner or a committee thereof will be designated as the plan administrator. The following description reflect the terms that are currently expected to be included in the Long-Term Incentive Plan.

General

We anticipate that the Long-Term Incentive Plan will provide for the grant, at the discretion of the plan administrator, of cash awards, options to purchase common units of the Company ("Options"), unit appreciation rights ("UARs"), restricted units, phantom units, unit awards, distribution equivalent rights and other unit-based awards intended to align the interests of service providers, including our Named Executive Officers, with those of the unitholders. The Long-Term Incentive Plan will limit the number of units that may be delivered pursuant to vested awards, subject to proportionate adjustment in the event of unit splits and similar events or certain transactions in accordance with the Long-Term Incentive Plan. Common units subject to awards that are cancelled, forfeited, withheld to satisfy exercise prices or tax withholding obligations, exchanged or otherwise terminated without delivery of common units will again be available for delivery pursuant to other awards under the Long-Term Incentive Plan.

Types of Awards

Cash Awards. Awards denominated in cash may be granted on terms and conditions, including vesting conditions, and for the consideration, including no consideration or minimum consideration as required by applicable law, as the plan administrator determines in its sole discretion.

Options and UARs. The Long-Term Incentive Plan may also permit the grant of Options, which represent the right to purchase a number of common units at a specified exercise price. UARs 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. Options and UARs may be granted to eligible individuals with any terms as the plan administrator of the Long-Term Incentive Plan may determine, consistent with the Long-Term Incentive Plan; however, an Option or UAR must have an exercise price equal to at least the fair market value of a common unit on the date of grant.

Restricted Units and Phantom Units. A restricted unit is a common unit subject to the restrictions on transferability and risk of forfeiture imposed by the plan administrator. 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 participant 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 Long-Term Incentive Plan may make grants of restricted units and phantom units under the Long-Term Incentive Plan that contain terms, consistent with the Long-Term Incentive Plan, 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 Long-Term Incentive Plan may, in its discretion, base vesting on the participant'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 Long-Term Incentive Plan) or as otherwise described in an award agreement. In the discretion of the plan administrator or as set forth in the applicable award agreement, distributions distributed with respect to restricted units prior to vesting may be subject to the same restrictions and risk of forfeiture as the restricted units with respect to which the distribution was made.

Distribution Equivalent Rights. The plan administrator of the Long-Term Incentive Plan, 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 Awards. Awards covering common units may be granted under the Long-Term Incentive Plan with terms and conditions, including restrictions on transferability, as the plan administrator of the Long-Term Incentive Plan may establish.

Other Unit-Based Awards. Other unit-based awards are awards denominated or payable in, valued in whole or in part by reference to, or otherwise based on or related to, the value of our common units. The vesting of other unit-based awards 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, other unit-based awards may be paid in cash and/or in units (including restricted units) or any combination thereof as the plan administrator of the Long-Term Incentive Plan 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.

Certain Transactions

If any change is made to our capitalization, such as a unit split, unit combination, unit distribution, exchange of units or other recapitalization, merger or otherwise, that results in an increase or decrease in the number of outstanding common units, appropriate adjustments will be made by the plan administrator in the number and type of common units subject to an award under the Long-Term Incentive Plan. The plan administrator will also have the discretion to make certain adjustments to awards in the event of a change in control, such as accelerating the vesting or exercisability of awards, requiring the surrender of an award, with or without consideration, or making any other adjustment or modification to the award that the plan administrator determines is appropriate in light of the transaction.

Clawback

All awards granted under the Long-Term Incentive Plan will be subject to clawback, cancellation, recoupment, rescission, payback, reduction or other similar action in accordance with any Company clawback policy or similar policy or any applicable law related to such actions.

Termination of Service

The consequences of the termination of a participant's membership on the board of directors of our general partner or other service arrangement will generally be determined by the plan administrator and set forth in the relevant award agreement.

Plan Amendment and Termination

The plan administrator may amend or terminate any award, award agreement or the Long-Term Incentive Plan at any time; however, unitholder approval will be required for any amendment to the extent necessary to comply with applicable law. Unitholder approval will be required to make amendments that (i) increase the aggregate number of common units that may be issued under the Long-Term Incentive Plan or (ii) change the classification of individuals eligible to receive awards under the Long-Term Incentive Plan. The Long-Term Incentive Plan will remain in effect for a period of 10 years (unless earlier terminated by the board of directors of our general partner).

Non-Employee Director Compensation

We did not pay any compensation, make any equity awards or non-equity awards to, or pay any other compensation to, any of the non-employee directors of our board of directors in 2022. We intend to implement a non-employee director compensation program in connection with this offering, but the details of this program have not yet been determined.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our common units that, upon the consummation of this offering and the related transactions, will be owned by:

- beneficial owners of more than 5% of our common units;
- each named executive officer of our general partner; and
- all directors, director nominees and executive officers of our general partner as a group.

The table assumes the underwriters' option to purchase additional common units from us is not exercised. The percentage of units beneficially owned is based on common units being outstanding immediately following this offering.

	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned
Name of Beneficial Owner[(1)]		
5% Unitholders:		
Bayou City Energy, L.P.[(2)]		
Named Executive Officers, Directors and Director Nominees		
Tom L. Ward		
Kevin R. White		
Daniel T. Reineke, Jr		
William McMullen		
All executive officers, directors and director nominees as a group (persons)		%

(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 14201 Wireless Way, Suite 300, Oklahoma City, OK 73134.

(2) William McMullen can be considered to beneficially own these common units through his control over Bayou City Energy, L.P.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Upon the consummation of this offering, assuming the underwriters do not exercise their option to purchase additional common units, the Sponsor will own common units representing an approximate % limited partner interest in us, and BCE-Mach Aggregator, which is owned by the Sponsor, will own % of our general partner. Certain members of our management will own common units representing an approximate % limited partner interest in us and will own % of our general partner. The Sponsor, who owns BCE-Mach Aggregator, and certain members of management will indirectly appoint all of the directors of our general partner, which will own 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 that our general partner expects to adopt prior to the closing of this offering.

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.
	Upon completion of this offering, the affiliates of our general partner will own common units, representing approximately % 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. Please read "The Partnership Agreement — Withdrawal or Removal of Our General Partner."
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 Management

Tom L. Ward, our Chief Executive Officer, and certain affiliated entities of Mr. Ward have royalty and working interests in certain of our wells. The payments related to these certain interests were $224,859 for the six months ended June 30, 2023, $595,474 for the year ended December 31, 2022, $451,933 for the year ended December 31, 2021 and $410,650 for the year ended December31, 2020. All of the royalty or working interest payments resulted from well interests in our Legacy Producing Assets.

Management Services Agreements

The Mach Companies have existing management services agreements with Mach Resources, pursuant to which Mach Resources manages and performs all aspects of oil and gas operations and other general and administrative functions of the Mach Companies. On a monthly basis, the Mach Companies reimburse certain costs and expenses to Mach Resources for performance under the existing management services agreements. For the six months ended June 30, 2023, the Mach Companies collectively paid $39.0 million to Mach Resources, which consists of $3.6 million for an annual management fee and $35.4 million for reimbursements of its costs and expenses under the existing management services agreements. For the year ended December 31, 2022, the Mach Companies collectively paid $67.0 million to Mach Resources, which consists of $3.4 million for an annual management fee and $63.6 million for reimbursements of its costs and expenses under the existing management services agreements among Mach Resources and the Mach Companies.

Other Transactions with Related Persons

BCE-Stack Development LLC ("BCE-Stack") is an affiliate of BCE-Mach Aggregator, a member of our predecessor, and previously was an owner of working and revenue interests in a subset of our predecessor's wells. BCE-Stack sold their interests in the wells to our predecessor on February 28, 2022. As of December 31, 2022 and as of June 30, 2023, our predecessor had no receivables or payables with BCE-Stack.

Agreements with Affiliates in Connection with the Reorganization Transactions

In connection with the closing of this offering, we, our general partner and its affiliates will enter into the various documents and agreements that will affect the Reorganization Transactions. These agreements have been 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 will be paid from the proceeds of this offering.

Contribution Agreements

In connection with the closing of this offering, we will enter into a contribution agreement that will effect the transactions whereby BCE, through its affiliate holding companies, will contribute 100% of its membership interests in the Mach Companies not already owned by BCE-Mach Aggregator to BCE-Mach Aggregator in exchange for additional membership interests in BCE-Mach Aggregator. Each of BCE- Mach Aggregator, the Management Members and Mach Resources will contribute 100% of their respective membership interests in the Mach Companies to the Company in exchange for a pro rata allocation of 100% of the limited partnership interests in the Company. While we believe this agreement is on terms no less favorable to any party than those that could have been negotiated with an unaffiliated third party, it will not be the result of arm's-length negotiations. All of the transaction expenses incurred in connection with these transactions will be paid from the proceeds of this offering.

Management Services Agreement

In connection with this offering, the Company will enter into a management services agreement ("MSA") with Mach Resources. Under the MSA, Mach Resources will manage and perform all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company will reimburse cash to Mach Resources for certain costs and expenses related to its performance under the MSA.

Procedures for Review, Approval or Ratification of Transactions with Related Persons

We expect that the Board will adopt policies for the review, approval and ratification of transactions with related persons. We anticipate the Board will adopt 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 and under which the Board or its authorized committee will periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. 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); provided, however, the MSA will require our general partner to seek approval by the conflicts committee of the Board in connection with an amendment to the MSA that, in the reasonable discretion of our general partner, adversely affects our unitholders.

Upon our adoption of our code of business conduct, we would expect that any executive officer will be required to avoid personal conflicts of interest and not compete against us, in each case unless approved by the Board.

Please read "Conflicts of Interest and Duties — Conflicts of Interest" for additional information regarding the relevant provisions of our partnership agreement.

The code of business conduct and ethics described above will be adopted in connection with the closing of this offering, and as a result, the transactions described above were not reviewed according to such procedures.

CONFLICTS OF INTEREST AND DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including the Sponsor and certain members of management) on the one hand, and us and our limited partners, on the other hand. In certain cases, directors and officers of our general partner have duties to manage our general partner at the direction of BCE-Mach Aggregator, which is owned by the Sponsor, and certain members of management. At the same time, our general partner has a duty to manage us in a manner that is not adverse to the best interests of our partnership. The Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by a general partner to limited partners and the partnership. Pursuant to these provisions, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of our general partner and the methods of resolving conflicts of interest. Our partnership agreement also specifically limits the remedies available to limited partners for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any other partner, on the other hand, our general partner will resolve that conflict. Our general partner may seek the approval of such resolution from the conflicts committee of the Board or from our unitholders. There is no requirement under our partnership agreement that our general partner seek the approval of the conflicts committee or our unitholders for the resolution of any conflict, and, under our partnership agreement, our general partner may decide to seek such approval or resolve a conflict of interest in any other way permitted by our partnership agreement, as described below, in its sole discretion; provided, however, the MSA will require our general partner to seek approval by the conflicts committee of the Board in connection with an amendment to the MSA that, in the reasonable discretion of our general partner, adversely affects our unitholders. Our general partner will make such decisions on a case-by-case basis. An independent third party is not required to evaluate the fairness of the resolution. In determining whether to refer a matter to the conflicts committee or to our unitholders for approval, our general partner will consider a variety of factors, including the nature of the conflict, the size and dollar amount involved, the identity of the parties involved and any other factors the Board deems relevant in determining whether it will seek approval from the conflicts committee or our unitholders. Whenever our general partner makes a determination to refer or not to refer any potential conflict of interest to the conflicts committee for approval or to seek or not to seek unitholder approval, our general partner is acting in its individual capacity, which means that it may act free of any duty or obligation whatsoever to us or our unitholders and will not be required to act in good faith or pursuant to any other standard or duty imposed by our partnership agreement or under applicable law, other than the implied contractual covenant of good faith and fair dealing. For a more detailed discussion of the duties applicable to our general partner, as well as the implied contractual covenant of good faith and fair dealing, please read "— Duties of Our General Partner."

Our general partner will not be in breach of its obligations under our partnership agreement or its duties to us or our limited partners if the resolution of the conflict is:

- approved by the conflicts committee, which our partnership agreement defines as "special approval";
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of 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 between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner seeks approval from the conflicts committee, then it will be presumed that, in making its decision, the conflicts committee 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. If our general partner does not seek approval from the conflicts committee or our unitholders and our general partner's board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth 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. Unless the resolution of a conflict is specifically provided for in our partnership agreement or the MSA, our general partner or the conflicts committee of our general partner's board of directors may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to subjectively believe that he or she is acting in a manner that is not adverse to the best interests of the partnership or that the determination to take or not to take action meets the specified standard; for example, the person may determine that a transaction is being entered into on terms no less favorable to us than those generally being provided to or available from unrelated third parties, or is "fair and reasonable" to us. In taking such action, such person may take into account the totality of the circumstances or the totality of the relationships between the parties involved, including other relationships or transactions that may be particularly favorable or advantageous to us. If that person has the required subjective belief, then the decision or action will be conclusively deemed to be in good faith for all purposes under our partnership agreement. Please read "Management — Committees of the Board of Directors — Conflicts Committee" for information about the conflicts committee of our general partner's board of directors.

Conflicts of interest could arise in the situations described below, among others:

Agreements between us, on the one hand, and our general partner and its affiliates, on the other hand, are not and will not be the result of arm's-length negotiations.

Neither our partnership agreement nor any of the other agreements, contracts and arrangements between us and our general partner and its affiliates are or will be the result of arm's-length negotiations. Our partnership agreement generally provides that any affiliated transaction, such as an agreement, contract or arrangement between us and our general partner and its affiliates that does not receive unitholder or conflicts committee approval, must be 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
- "fair and reasonable" to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner's affiliates may compete with us and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. However, affiliates of our general partner are not prohibited from engaging in other businesses or activities, including those that might directly compete with us. In addition, under our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to our general partner and its affiliates. As a result, neither our general partner nor any of its affiliates have any obligation to present business opportunities to us.

Our general partner is allowed to take into account the interests of parties other than us in resolving conflicts of interest.

Our partnership agreement contains provisions that permissibly modify and reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner or otherwise, free of any duty or obligation whatsoever to us and our unitholders, including any duty to act in a manner not adverse to the best interests of us or 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 our partnership agreement does not provide for a clear course of action. This 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 any limited partner. Examples of decisions that our general partner may make in its individual capacity include the allocation of corporate opportunities among us and our affiliates, the exercise of its limited call right or its voting rights with respect to the units it owns, whether to exercise its registration rights, and whether or not to consent to any merger, consolidation or conversion of the partnership or amendment to our partnership agreement.

We do not have any officers or employees and rely solely on officers and employees of our general partner and its affiliates.

Affiliates of our general partner conduct businesses and activities of their own in which we have no economic interest. There could be material competition for the time and effort of the officers and employees who provide services to our general partner.

Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties and limits our general partner's liabilities and the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty under applicable Delaware law.

Our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and our general partner has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our general partner shall not have any liability to us or our limited partners for decisions made in its capacity so long as such decisions are made in good faith;
- generally provides that in a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our public 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 is either on terms no less favorable to us than those generally being provided to or available from unrelated third parties or is "fair and reasonable" to us, considering the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us, 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 us challenging such decision, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission 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 or directors, as the cases may be, 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.

By purchasing a common unit, a common unitholder will be deemed to have agreed to become bound by the provisions in our partnership agreement, including the provisions discussed above.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of, or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into or exchangeable for equity interests of the partnership, and the incurring of any other obligations;
- the making of tax, regulatory and other filings, or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets;
- the acquisition, disposition, mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets or the merger or other combination of us with or into another person;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of cash held by the partnership;
- the selection and dismissal of employees and agents, attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;
- the maintenance of insurance for our benefit and the benefit of our partners and indemnitees;
- the formation of, or acquisition of an interest in, and the contribution of property and the making of loans to, any further limited or general partnerships, joint ventures, corporations, limited liability companies or other entities;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the purchase, sale or other acquisition or disposition of our equity interests, or the issuance of additional options, rights, warrants and appreciation rights relating to our equity interests; and
- the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Please read "The Partnership Agreement" for information regarding the voting rights of unitholders.

We will reimburse our general partner and its affiliates for expenses.

Pursuant to our partnership agreement, 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 provides that our general partner will determine such other expenses that are allocable to us, and our partnership agreement does not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. Such reimbursements will be made prior to making any distributions on our common units. Please read "The Partnership Agreement — Reimbursement of Expenses."

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party to such agreements has recourse only against our assets and not against our general partner or its assets or any affiliate of our general partner or its assets. Our partnership agreement permits our general partner to limit its or our liability, even if we could have obtained terms that are more favorable without the limitation on liability.

Common units are subject to our general partner's limited call right.

Our general partner may exercise its right to call and purchase common units as provided in our partnership agreement or assign this right to one of its affiliates or to us free of any liability or obligation to us or our partners. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read "The Partnership Agreement — Limited Call Right."

Limited partners have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us, on the one hand, and our general partner and its affiliates, on the other, will not grant to the limited partners, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The attorneys, independent accountants and others who perform services for us have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee and may also perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

Duties of our General Partner

The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by a general partner to limited partners and the partnership, provided that partnership agreements may not eliminate the implied contractual covenant of good faith and fair dealing. This implied contractual covenant is a judicial doctrine utilized by Delaware courts in connection with interpreting ambiguities in partnership agreements and other contracts and does not form the basis of any separate or independent fiduciary duty in addition to the express contractual duties set forth in our partnership agreement. Under the implied contractual covenant of good faith and fair dealing, a court will enforce the reasonable expectations of the partners at the time the partnership agreement was entered into where the language in our partnership agreement does not provide for a clear course of action.

As permitted by the Delaware Act, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of our general partner and the methods of resolving conflicts of interest. We have adopted these provisions to allow our general partner or its affiliates to engage in transactions with us that otherwise might be prohibited or restricted by state-law fiduciary standards and to take into account the interests of other parties in addition to or in lieu of our interests when resolving conflicts of interest. We believe this is appropriate and necessary because the Board has duties to manage our general partner at the direction of BCE-Mach Aggregator, which is owned by the Sponsor, and certain members of management. Without these provisions, our general partner's ability to make decisions involving conflicts of interest would be restricted. These provisions enable our general partner to take into consideration the interests of all parties involved in the proposed action. These provisions also strengthen the ability of our general partner to attract and retain experienced and capable directors. These provisions disadvantage the limited partners because they restrict the remedies available to limited partners for actions that, without those provisions, might constitute breaches of fiduciary duty, as described below and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest. The following is a summary of:

- the fiduciary duties imposed on general partners of a limited partnership by Delaware law in the absence of partnership agreement provisions to the contrary;
- the contractual duties of our general partner contained in our partnership agreement that replace the fiduciary duties referenced in the preceding bullet that would otherwise be imposed by Delaware law on our general partner; and
- certain rights and remedies of our limited partners contained in our partnership agreement and the Delaware Act.

Delaware law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner of a Delaware limited partnership to use that amount of care that an ordinarily careful and prudent person would use in similar circumstances and to consider all material information reasonably available in making business decisions. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present unless such transaction were entirely fair to the partnership. Our partnership agreement modifies these standards as described below.
Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith," meaning that it subjectively believed that the decision was not adverse to our best interests, and our general partner will not be subject to any other standard under our partnership agreement or applicable law, other than the implied contractual covenant of good faith and fair dealing. If our general partner has the required subjective belief, then the decision or action will be conclusively deemed to be in good faith for all purposes under our partnership agreement. In taking such action, our general partner may take into account the totality of the circumstances or the totality of the relationships between the parties involved, including other relationships or transactions that may be particularly favorable or advantageous to us. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act free of any duty or obligation whatsoever to us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. These standards reduce the obligations to which our general partner would otherwise be held under applicable Delaware law. Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the public common unitholders or the conflicts committee of the Board must be 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 • "fair and reasonable" to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us. If our general partner seeks approval from the conflicts committee, then it will be presumed that, in making its decision, the conflicts committee 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. If our general partner does not seek approval from the public common unitholders or the conflicts committee and the Board determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the 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. These standards reduce the obligations to which our general partner would otherwise be held.

	In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner, its affiliates and their officers and directors will not be liable for monetary damages to us or, our limited partners for losses sustained or liabilities incurred as a result of any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such person 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.
Rights and remedies of limited partners	The Delaware Act favors the principles of freedom of contract and enforceability of partnership agreements and allows our partnership agreement to contain terms governing the rights of our unitholders. The rights of our unitholders, including voting and approval rights and the ability of the partnership to issue additional units, are governed by the terms of our partnership agreement. Please read "The Partnership Agreement." As to remedies of unitholders, the Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has wrongfully refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These actions include actions against a general partner for breach of its fiduciary duties, if any, or of our partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

By purchasing our common units, each common unitholder will be deemed to have agreed to be bound by the provisions in our partnership agreement, including the provisions discussed above. Please read "Description of the Common Units — Transfer Agent and Register — Transfer of Common Units." This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign our partnership agreement does not render our partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and its officers, directors and managers, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that our general partner or these persons acted in bad faith or engaged in intentional fraud or willful misconduct. We also must provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was criminal. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent that these provisions purport to include indemnification for liabilities arising under the U.S. federal securities laws, in the opinion of the SEC such indemnification is contrary to public policy and therefore unenforceable. Please read "The Partnership Agreement — Indemnification."

DESCRIPTION OF THE COMMON UNITS

The Units

The common units represent limited partner interests in us. The holders of common units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units in and to partnership distributions, please read this section and “Our Cash Distribution Policy and Restrictions on Distributions.” For a description of other rights and privileges of limited partners under our partnership agreement, including voting rights, please read “The Partnership Agreement.”

Transfer Agent and Registrar

Duties

American Stock Transfer & Trust Company, LLC, a New York limited liability trust company will serve as registrar and transfer agent for the common units. We will pay all fees charged by the transfer agent for transfers of common units, except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates or to cover taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There will be no charge to our unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their respective stockholders, directors, officers and employees against all claims and losses that may arise out of their actions for their activities in that capacity, except for any liability due to any gross negligence or willful misconduct of the indemnitee.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of our partnership agreement; and
- gives the consents, waivers and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

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. Please read “The Partnership Agreement — Non-Citizen Unitholders; Redemption.”

In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units. Our general partner will cause any transfers to be recorded on our books and records from time to time (or shall cause the transfer agent to do so, as applicable).

The transferor of common units will have a duty to provide the transferee with all information that may be necessary to transfer the common units. The transferor will not have a duty to insure the execution of the transfer application and certification by the transferee and will have no liability or responsibility if the transferee neglects or chooses not to execute and forward the transfer application and certification to the transfer agent.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder’s rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and any transfers are subject to the laws governing transfers of securities.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read “Our Cash Distribution Policy and Restrictions on Distributions” and “Provisions of Our Partnership Agreement Relating to Cash Distributions;”
- with regard to the duties of our general partner, please read “Conflicts of Interest and Duties;”
- with regard to the transfer of common units, please read “Description of the Common Units — Transfer Agent and Registrar — Transfer of Common Units;” and
- with regard to allocations of taxable income, taxable loss and other matters, please read “Material U.S. Federal Income Tax Consequences.”

Organization and Duration

Our partnership was organized under Delaware law and will have a perpetual existence unless dissolved, wound up and terminated pursuant to the terms of our partnership agreement and the Delaware Act.

Purpose

Our purpose under our partnership agreement is to engage in any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law. However, our general partner may not cause us to engage, directly or indirectly, in any business activity that it determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes, except as otherwise provided below under “— Election to be Treated as a Corporation.”

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the ownership, acquisition, exploitation and development of oil and natural gas properties and the ownership, acquisition and operation of related assets, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described under “— Limited Liability.”

Limited Voting Rights

The following is a summary of the unitholder vote required for each of the matters specified below. Matters that call for the approval of a “unit majority” require the approval of a majority of the common units.

Various matters require the approval of a “unit majority,” which means:

- the approval of a majority of the outstanding common units.

At the closing of this offering, the affiliates of our general partner (including the Sponsor) will have the ability to control the passage of, as well as the ability to control the defeat of, any amendment which requires a unit majority by virtue of their approximately   % ownership of our common units.

In voting their common units, our general partner and its affiliates (including the Sponsor) will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. The holders of a majority of the common units (including common units deemed owned by our general partner and its affiliates) entitled to vote at the meeting, represented in person or by proxy shall constitute a quorum at a meeting of common unitholders, unless any such action requires approval by holders of a greater percentage of such units in which case the quorum shall be such greater percentage.

Issuance of additional units	No approval right. Please read "— Issuance of Additional Partnership Interests."
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read "— Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority, in certain circumstances. Please read "— Merger, Consolidation, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read "— Termination and Dissolution."
Continuation of our business upon certain events of dissolution	Unit majority. Please read "— Termination and Dissolution."
Withdrawal of our general partner	Under most circumstances, the approval of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates (including the Sponsor and certain members of management), is required for the withdrawal of our general partner in a manner that would cause a dissolution of our partnership. Please read "— Withdrawal or Removal of Our General Partner."
Removal of our general partner	Not less than 66⅔% of the outstanding common units, including units held by our general partner and its affiliates (including the Sponsor and certain members of management), voting as a single class. Please read "— Withdrawal or Removal of Our General Partner."
Transfer of our general partner interest	Our general partner may transfer any or all of its general partner interest in us without a vote of our unitholders. Please read "— Transfer of General Partner Interest."
Transfer of ownership interests in our general partner	No unitholder approval required. Please read "— Transfer of Ownership Interests in Our General Partner."
Election to be treated as a corporation	No approval right. Please read "— Election to be Treated as a Corporation."

The limited liability company agreement of our general partner provides that the board of directors of our general partner will not take any action without approval of BCE-Mach Aggregator, which is wholly owned by the Sponsor, and certain members of management, with respect to an extraordinary matter that would have, or would reasonably be expected to have, a material effect, directly or indirectly, on Sponsor's or management's interests in our general partner. Extraordinary matters include, but are not limited to:

- the commencement of any action relating to bankruptcy, insolvency, reorganization or relief of debtors by our general partner, us or any of our subsidiaries or joint ventures,
- a merger, consolidation, recapitalization or similar transaction involving our general partner, us or any of our material subsidiaries or joint ventures,
- a sale, exchange or other transfer not in the ordinary course of business of a substantial portion of the assets of ours, our general partner or any of our subsidiaries or joint ventures, viewed on a consolidated basis, in one or a series of related transactions,

- the issuance or repurchase of any equity interests in our general partner or a joint venture,
- a dissolution or liquidation of our general partner, us or any of our material subsidiaries or joint ventures, and
- any material amendment of the governing documents of a joint venture, or a transfer, sale or other disposition of by us, our general partner or any of our subsidiaries of equity interests in a joint venture.

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the 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);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a fiduciary 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;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. 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.

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. 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 and provisions 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 courts in Delaware) in connection with any such claims, suits, actions or proceedings.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he or she otherwise acts in conformity with the provisions of our partnership agreement, his or her liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he or she is obligated to contribute to us for his or her common units plus his or her share of any undistributed profits and assets. If it were determined, however, that the right or exercise of the right by our limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to the partnership agreement; or
- to take other action under the partnership agreement;

constituted “participation in the control” of our business for the purposes of the Delaware Act, then our limited partners could be held personally liable for our obligations under Delaware law, to the same extent as our general partner. This liability would extend to persons who transact business with us and reasonably believe that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our operating subsidiaries conduct business in Oklahoma, Kansas and Texas, and we may have operating subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as an owner of our operating subsidiary may require compliance with legal requirements in the jurisdictions in which our operating subsidiary conducts business, including qualifying our operating subsidiary to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership in our subsidiaries or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by our limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted “participation in the control” of our business for purposes of the statutes of any relevant jurisdiction, then our limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of our limited partners.

Issuance of Additional Partnership Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of our unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have special voting or other rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity interests, which may effectively rank senior to our common units.

Our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units or other partnership interests whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the aggregate percentage interest in us of our general partner and its affiliates, including such interest represented by common units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. To adopt a proposed amendment, other than the amendments discussed below under "— No Unitholder Approval," our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of our limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provisions of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates (including the Sponsor and certain members of management)). Upon the consummation of this offering, affiliates of our general partner (including the Sponsor and certain members of management) will own an aggregate of approximately % of our outstanding common units, representing an aggregate of approximately % of our outstanding limited partnership units.

No Limited Partner Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate for us to qualify or to continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we, nor our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes, except as otherwise provided below under "— Election to be Treated as a Corporation";
- a change in our fiscal year or taxable year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from being subjected, in any manner, to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed by the U.S. Department of Labor;
- an amendment that sets forth the designations, preferences, rights, powers and duties of any class or series of additional partnership securities or rights to acquire partnership securities, that our general partner determines to be necessary or appropriate or advisable for the authorization or issuance of additional partnership securities or rights to acquire partnership securities;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement or plan of conversion that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate to reflect and account for the formation by us of, or our investment in, any corporation, partnership, limited liability company, joint venture or other entity, as otherwise permitted by our partnership agreement;
- any amendment necessary to require our limited partners to provide a statement, certification or other evidence to us regarding whether such limited partner is subject to United States federal income taxation on the income generated by us and to provide for the ability of our general partner to redeem the units of any limited partner who fails to provide such statement, certification or other evidence;
- an amendment that our general partner determines to be necessary or appropriate or advisable in connection with conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect our limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of our units or to comply with any rule, regulation, guideline or requirement of any securities exchange on which our units are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will not affect the limited liability of any limited partner under Delaware law. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding common units unless we first obtain such an opinion.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the holders of the type or class of units so affected, but no vote will be required by the holders of any class or classes or type or types of units that our general partner determines are not adversely affected in any material respect. Any amendment that reduces the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased.

Merger, Consolidation, Sale or Other Disposition of Assets

A merger, consolidation, or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation, or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interest of us or our limited partners, other than the implied contractual covenant of good faith and fair dealing.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us, among other things, to sell, exchange or otherwise dispose of all or substantially all of our and our subsidiaries' assets in a single transaction or a series of related transactions, including by way of merger, consolidation, conversion or other combination or sale of ownership interests of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger, consolidation or conversion without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction will not result in an amendment to our partnership agreement (other than an amendment that the general partner could adopt without the consent of the other partners), each of our units will be an identical unit of our partnership following the transaction, and the partnership interests to be issued do not exceed 20% of our outstanding partnership interests immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide our limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger, consolidation or conversion, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until dissolved and terminated under our partnership agreement. We will dissolve upon:

- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner, other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or a withdrawal or removal followed by approval and admission of a successor;
- the election of our general partner to dissolve us, if approved by the holders of a unit majority;
- the entry of a decree of judicial dissolution of our partnership pursuant to the provisions of the Delaware Act; or
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law.

Upon a dissolution under the first bullet above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and
- neither our partnership nor our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions — Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to , 2033 without obtaining the approval of the holders of at least a majority of our outstanding common units, excluding common units held by our general partner and its affiliates (including the Sponsor and certain members of management), and furnishing an opinion of counsel regarding limited liability and tax matters. On or after , 2033, our general partner may withdraw as our general partner without first obtaining approval of any unitholder by giving at least 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw as our general partner without unitholder approval upon 90 days' notice to our limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates (including the Sponsor and certain members of management). In addition, our partnership agreement permits our general partner to sell or otherwise transfer all of its general partner interest in us without the approval of our unitholders. Please read "— Transfer of General Partner Interest."

Upon voluntary withdrawal of our general partner by giving notice to the other partners, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated. Please read "— Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66⅔% of our outstanding units, voting together as a single class, including units held by our general partner and its affiliates (including the Sponsor and certain members of management), and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of our outstanding common units. The ownership of more than 33⅓% of our outstanding units by our general partner and its affiliates (including the Sponsor and certain members of management) would give them the practical ability to prevent our general partner's removal. Upon the consummation of this offering, affiliates of our general partner (including the Sponsor and certain members of management) will own an aggregate of approximately % of our outstanding common units, representing approximately % of our outstanding limited partnership units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist our general partner will have the right to convert its general partner interest into common units or to receive cash from the successor general partner in exchange for those interests based on the fair market value of the interests at the time.

In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the departing general partner's general partner interest for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and its affiliate and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and its affiliate and the successor general partner will determine the fair market value. If the departing general partner and its affiliate and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Our general partner may transfer all or any of its general partner interest to an affiliate or a third party without the approval of our unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates (including the Sponsor and certain members of management) may at any time transfer common units to one or more persons without unitholder approval.

Transfer of Ownership Interests in Our General Partner

At any time, the members of our general partner may sell or transfer all or part of their membership interests in our general partner to an affiliate or a third party without the approval of our unitholders.

Election to be Treated as a Corporation

If at any time our general partner determines that (i) we should no longer be characterized as a partnership but instead as an entity taxed as a corporation for U.S. federal income tax purposes or (ii) common units held by some or all unitholders should be converted into or exchanged for interests in a newly formed entity taxed as a corporation for U.S. federal income tax purposes whose sole asset is interests in us ("parent corporation"), then our general partner may, without unitholder approval, reorganize us and cause us to be treated as an entity taxable as a corporation for U.S. federal income tax purposes or cause us to engage in a merger or other transaction pursuant to which common units held by some or all unitholders will be converted into or exchanged for interests in the parent corporation. In addition, if our general partner causes partnership interests in us to be held by a parent corporation, our Existing Owners may choose to retain their partnership interests in us rather than convert or exchange their partnership interests into parent corporation shares. 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 vary depending on the unitholder's particular situation and may vary from the tax liability of each of our Existing Owners. 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.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates (including the Sponsor and certain members of management) acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the Board.

Limited Call Right

If at any time our general partner and its affiliates (including the Sponsor and certain members of management) own more than % of our then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days' notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price calculated in accordance with our partnership agreement as of the date three business days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have its limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The federal income tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of its common units in the market. Please read "Material U.S. Federal Income Tax Consequences — Disposition of Units."

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of common units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take such action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, entitled to vote at the meeting represented in person or by proxy, will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "— Issuance of Additional Partnership Interests." However, if at any time any person or group, other than our general partner and its affiliates (including the Sponsor and certain members of management) or a direct or subsequently approved transferee of our general partner or its affiliates or a transferee of that person or group approved by our general partner or a person or group specifically approved by our general partner or the Board, as applicable, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held by a nominee or in a street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent or an exchange agent.

Status as Limited Partner

By transfer of any common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described under "— Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Unitholders; Redemption

We may acquire interests in oil and natural gas leases on United States federal lands in the future. To comply with certain U.S. laws relating to the ownership of interests in oil and natural gas leases on federal lands, our general partner, acting on our behalf, 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. Further, the units held by such unitholder will not be entitled to any voting rights and may not receive distributions in-kind upon our liquidation.

Furthermore, we have the right to redeem all of the common units of any holder that our general partner concludes is an not an eligible holder pursuant to our partnership agreement or fails to furnish the information requested by our general partner. The redemption price in the event of such redemption for each unit held by such unitholder will be the current market price of such unit (the date of determination of which shall be the date fixed for redemption). The redemption price will be paid, as determined by our general partner, in cash or by delivery of a promissory note. Any such promissory note will bear interest at the rate of 5% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof.

Indemnification

Under our partnership agreement, unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such person 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, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events,:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a director, officer, manager, managing member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as a director, officer, manager, managing member, partner, fiduciary or trustee of another person at the request of our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance covering liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. 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 general partner is entitled to determine in good faith the expenses that are allocable to us. The expenses for which we are required to reimburse our general partner are not subject to any caps or other limits.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For financial reporting and tax purposes, our fiscal year is the calendar year.

We will mail or make available to record holders of common units, within 105 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent registered public accounting firm. Except for our fourth quarter, we will also mail or make available a report containing unaudited financial statements within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website which we maintain.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on the cooperation of our unitholders in supplying us with specific information. Every unitholder will receive information to assist it in determining its federal and state tax liability and filing its federal and state income tax returns, regardless of whether such unitholder supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, obtain:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement and our certificate of limited partnership and related amendments thereto; and
- certain information regarding the status of our business and financial condition.

Our general partner may, and intends to, keep confidential from the limited partners, trade secrets or other information the disclosure of which our general partner determines is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the right to information that a limited partner would otherwise have under Delaware law.

Registration Rights

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 or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. Please read "Units Eligible for Future Sale."

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered hereby, the Existing Owners will hold an aggregate of common units. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in this offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1.0% of the total number of the securities outstanding; or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A unitholder who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least six months (provided we are in compliance with the current public information requirement) or one year (regardless of whether we are in compliance with the current public information requirement), would be entitled to sell those common units under Rule 144 without regard to the volume limitations, manner of sale provisions and notice requirements of Rule 144.

Our Partnership Agreement and Registration Rights

Our partnership agreement provides that we may issue an unlimited number of limited partner interests of any type without a vote of the unitholders. Any issuance of additional common units or other equity interests would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, our common units then outstanding. Please read "The Partnership Agreement — Issuance of Additional Partnership Interests."

Under our partnership agreement, our general partner and its affiliates, including the Sponsor and certain members of management, have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any common units or other partnership interests that they hold, which we refer to as registerable securities. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any registerable securities to require registration of such registerable securities and to include any such registerable securities in a registration by us of common units or other partnership interests, including common units or other partnership interests offered by us or by any unitholder. Our general partner and its affiliates will continue to have these registration rights for two years following the withdrawal or removal of our general partner. In connection with any registration of units held by our general partner or its affiliates, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts. Except as described below, our general partner and its affiliates may sell their common units or other partnership interests in private transactions at any time, subject to compliance with applicable laws.

Lock-Up Agreements

We, the Sponsor and all of our directors and executive officers have agreed not to sell any common units or securities convertible into or exchangeable for common units for a period of 180 days from the date of this prospectus, subject to certain exceptions. For a description of these lock-up provisions, please read "Underwriting."

Registration Statement on Form S-8

Prior to the completion of this offering, we expect to adopt a new long-term incentive plan (the "Long-Term Incentive Plan"). If adopted, we intend to file a registration statement on Form S-8 under the Securities Act to register common units issuable under the Long-Term Incentive Plan. This registration statement on Form S-8 is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, common units issued under the Long-Term Incentive Plan will be eligible for resale in the public market without restriction after the effective date of the Form S-8 registration statement, subject to applicable vesting requirements, Rule 144 limitations applicable to affiliates and the lock-up restrictions described above.

MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

This section is a summary of certain material U.S. federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Kirkland & Ellis LLP, counsel to our general partner and us, insofar as it relates to legal conclusions with respect to matters of U.S. federal income tax law. This section is based upon current provisions of the U.S. Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed U.S. Treasury regulations promulgated under the Code (the "Treasury Regulations") and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Mach Natural Resources and our operating subsidiaries.

This discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to other categories of unitholders, such as corporations (or entities treated as corporations for U.S. federal income tax purposes), partnerships (or entities treated as partnerships for U.S. federal income tax purposes), trusts and estates. This discussion does not address all tax considerations that may be relevant to a particular unitholder in light of the unitholder's circumstances. Moreover, this discussion does not address, or addresses only to a limited extent, the tax considerations that may be applicable to certain categories of unitholders that may be subject to special tax treatment under U.S. federal income tax laws, such as:

- U.S. expatriates and former citizens or long-term residents of the United States;
- banks, insurance companies and other financial institutions;
- tax-exempt institutions and IRAs;
- foreign persons (including controlled foreign corporations, passive foreign investment companies and foreign persons eligible for the benefits of an applicable income tax treaty with the United States);
- real estate investment trusts;
- mutual funds;
- dealers or traders in securities or currencies;
- U.S. persons whose "functional currency" is not the U.S. dollar;
- persons holding their units as part of a straddle, hedge, conversion, constructive sale or other integrated transaction; and
- persons subject to special tax accounting rules as a result of any item of gross income with respect to our common units being taken into account in an applicable financial statement.

In addition, this discussion does not comment on all U.S. federal income tax matters affecting us or our unitholders, such as the application of the alternative minimum tax, and only comments to a limited extent on state, local and foreign tax consequences. ***Accordingly, we encourage each prospective unitholder to consult his own tax advisor in analyzing the U.S. federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units and potential changes in applicable laws***.

No ruling has been requested from the IRS regarding our characterization as a partnership for tax purposes. Instead, we will rely on opinions of Kirkland & Ellis LLP. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our common units, including the prices at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

Unless otherwise noted, all statements as to matters of U.S. federal income tax law and legal conclusions with respect thereto, but not as to factual matters, contained in this section are the opinion of Kirkland & Ellis LLP and are based on the accuracy of the representations made by us. Notwithstanding the foregoing, and for the reasons described below, Kirkland & Ellis LLP has not rendered an opinion with respect to the following specific U.S. federal income tax issues: (i) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read "— Tax Consequences of Unit Ownership — Treatment of Short Sales"); (ii) whether all aspects of our method for allocating taxable income and losses is permitted by existing Treasury Regulations (please read "— Disposition of Common Units — Allocations Between Transferors and Transferees"); (iii) whether our method for taking into account Section 743 adjustments is sustainable in certain cases (please read "— Tax Consequences of Unit Ownership — Section 754 Election" and "— Uniformity of Units"); and (iv) whether percentage depletion will be available to a unitholder or the extent of the percentage depletion deduction (please read "— Tax Treatment of Operations — Depletion Deductions").

Partnership Status

A partnership is not a taxable entity and generally incurs no U.S. federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his U.S. federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable to the partnership or the partner unless the amount of cash distributed to him is in excess of the partner's adjusted basis in his partnership interest.

Section 7704 of the Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the exploration, development, mining or production, processing, refining, transportation and marketing of certain minerals and natural resources, including crude oil, natural gas and certain products thereof, certain related hedging activities, certain activities that are intrinsic to other qualifying activities, and our allocable share of our subsidiaries' income from these sources. Other types of qualifying income include interest (other than from a financial business), dividends, real property rents, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than % of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, Kirkland & Ellis LLP is of the opinion that at least 90% of our current gross income constitutes qualifying income.

The IRS has made no determination as to our status or the status of our operating subsidiaries for U.S. federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Code. Instead, we will rely on the opinion of Kirkland & Ellis LLP on such matters. It is the opinion of Kirkland & Ellis LLP that, based upon the Code, the Treasury Regulations, published revenue rulings and court decisions and the representations described below that:

- We will be classified as a partnership for U.S. federal income tax purposes; and
- Each of our operating subsidiaries will be treated as a partnership or will be disregarded as an entity separate from us for U.S. federal income tax purposes.

In rendering its opinion, Kirkland & Ellis LLP has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Kirkland & Ellis LLP has relied include:

- Neither we nor any of our operating subsidiaries has elected or will elect to be treated as a corporation for U.S. federal income tax purposes;
- For each taxable year, more than 90% of our gross income has been and will be income of the type that Kirkland & Ellis LLP has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Code; and

- Each commodity hedging transaction that we treat as resulting in qualifying income has been and will be appropriately identified as a hedging transaction pursuant to the applicable Treasury Regulations, and has been and will be associated with oil, gas or products thereof that are held or to be held by us in activities of a type that Kirkland & Ellis LLP has opined or will opine result in qualifying income.

We believe that these representations have been true in the past, are true as of the date hereof and expect that these representations will continue to be true in the future.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for U.S. federal income tax purposes.

In addition, our general partner may, without unitholder approval, reorganize us and cause us to be treated as an entity taxable as a corporation for U.S. federal income tax purposes or cause us to enter into a transaction in which common units held by some or all unitholders will be converted into or exchanged for interests in a newly formed entity taxed as a corporation for U.S. federal income tax purposes whose sole asset is interests in us. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. Please read "The Partnership Agreement — Election to be Treated as a Corporation."

If we were treated as an association taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder generally would be treated as (i) taxable dividend income, to the extent of our current and accumulated earnings and profits, (ii) then as a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, and (iii) then as taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the common units.

The discussion below is based on Kirkland & Ellis LLP's opinion that we will be classified as a partnership for U.S. federal income tax purposes.

Limited Partner Status

Unitholders of Mach Natural Resources will be treated as partners of Mach Natural Resources for U.S. federal income tax purposes. In addition, unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of Mach Natural Resources for U.S. federal income tax purposes.

A beneficial owner of common units whose common units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those common units for U.S. federal income tax purposes. Please read "— Tax Consequences of Unit Ownership — Treatment of Short Sales." Income, gains, losses or deductions would not appear to be reportable by a unitholder who is not a partner for U.S. federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for U.S. federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their tax advisors with respect to the tax consequences to them of holding common units. The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Mach Natural Resources for U.S. federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

Subject to the discussion below under "— Entity-Level Collections," we will not pay any U.S. federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether we make cash distributions to him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions

Distributions of cash by us to a unitholder generally will not be taxable to the unitholder for U.S. federal income tax purposes, except to the extent the amount of any such distribution exceeds his tax basis in his common units immediately before the distribution. Cash distributions in excess of a unitholder's tax basis generally will be treated as gain from the sale or exchange of the common units, taxable in accordance with the rules described under "— Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution by us of cash to that unitholder. To the extent our distributions cause a unitholder's "at-risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "— Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. This deemed distribution may constitute a non-pro rata distribution. A non-pro rata distribution may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our (i) "unrealized receivables," including depreciation recapture, depletion recapture and intangible drilling costs recapture, or (ii) substantially appreciated "inventory items," each as defined in the Code (collectively, "Section 751 Assets"). To that extent, the unitholder will be treated as having been distributed his proportionate share of the Section 751 Assets and then as having exchanged those assets with us in return for the non-pro rata portion of the distribution (or deemed distribution) made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis (often zero) for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of taxable income to distributions

We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the year ending December 31, 2025, will be allocated, on a cumulative basis, an amount of U.S. federal taxable income for that period that will be % or less of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders will increase. Our estimate is based upon many assumptions regarding our business operations, including assumptions as to our revenues, capital expenditures, cash flow, net working capital and anticipated cash distributions. These estimates and assumptions are subject to, among other factors, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct.

The actual ratio of allocable taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be higher, and perhaps substantially higher, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to make quarterly cash distributions from our available cash on all common units, yet we only distribute the quarterly cash distributions from our available cash on all common units;

- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depletion, depreciation or amortization for U.S. federal income tax purposes or that is depletable, depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering; or
- legislation is enacted that limits or repeals certain U.S. federal income tax preferences currently available to oil and gas exploration and production companies (please read "— Recent Legislative Developments").

Basis of Common Units

A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income, by any increases in his share of our nonrecourse liabilities and, on the disposition of a common unit, by his share of certain items related to business interest not yet deductible by him due to applicable limitations. Please read "— Limitations on Interest Deductions." That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by depletion deductions taken by him to the extent such deductions do not exceed his proportionate share of the adjusted tax basis of the underlying properties, by any decreases in his share of our nonrecourse liabilities, by his share of our excess business interest (generally, the excess of our business interest over the amount that is deductible) and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read "— Disposition of Common Units — Recognition of Gain or Loss."

Limitations on Deductibility of Losses

The deduction by a unitholder of his share of our losses will be limited to the tax basis in his common units and, in the case of an individual unitholder, estate, trust or certain closely-held corporations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder subject to these limitations must recapture losses deducted in previous years to the extent that distributions cause his at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder's tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain would no longer be utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his common units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by (i) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (ii) any amount of money he borrows to acquire or hold his common units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the common units for repayment. A unitholder's at-risk amount will increase or decrease as the tax basis of the unitholder's common units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The at-risk limitation applies on an activity-by-activity basis, and in the case of oil and natural gas properties, each property is treated as a separate activity. Thus, a taxpayer's interest in each oil or natural gas property is generally required to be treated separately so that a loss from any one property would be limited to the at-risk amount for that property and not the at-risk amount for all the taxpayer's oil and natural gas properties. It is uncertain how this rule is implemented in the case of multiple oil and natural gas properties owned by a single entity treated as a partnership for U.S. federal income tax purposes. However, for taxable years ending on or before the date on which further guidance is published, the IRS will permit aggregation of oil or natural gas properties we own in computing a unitholder's at-risk limitation with respect to us. If a unitholder were required to compute his at-risk amount separately with respect to each oil or natural gas property we own, he might not be allowed to utilize his share of losses or deductions attributable to a particular property even though he has a positive at-risk amount with respect to his common units as a whole.

In addition to the basis and at-risk limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and certain closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or a unitholder's investments in other publicly traded partnerships, or the unitholder's salary, active business or other income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive loss limitations are applied after other applicable limitations on deductions, including the at-risk rules and the basis limitation described above.

An additional loss limitation may apply to certain of our unitholders for taxable years beginning before January 1, 2029. A non-corporate unitholder will not be allowed to take a deduction for certain excess business losses in such taxable years. An excess business loss is the excess (if any) of a taxpayer's aggregate deductions for the taxable year that are attributable to the trades or businesses of such taxpayer (determined without regard to the excess business loss limitation or any deduction allowable for net operating losses, qualified business income or capital losses) over the aggregate gross income or gain of such taxpayer for the taxable year that is attributable to such trades or businesses (subject to certain limitations in the case of capital gains) plus a threshold amount. The current threshold amount is equal to $289,000, or $578,000 for taxpayers filing a joint return. Any losses disallowed in a taxable year due to the excess business loss limitation may be used by the applicable unitholder in the following taxable year if certain conditions are met. Unitholders to which this excess business loss limitation applies will take their allocable share of our items of income, gain, loss and deduction into account in determining this limitation. This excess business loss limitation will be applied to a non-corporate unitholder after the passive loss limitations and may limit such unitholders' ability to utilize any losses we generate allocable to such unitholder that are not otherwise limited by the basis, at-risk and passive loss limitations described above.

Limitations on Interest Deductions

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.

In addition, the deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense is interest expense on indebtedness that is properly allocable to property held for investment, which includes (i) property that produces portfolio income (for example, interest and dividends) and (ii) any interest held by the taxpayer in an activity that is not a passive activity and with respect to which the taxpayer does not materially participate. Net investment income is gross income from property held for investment, less deductible expenses (other than interest) directly connected with the production of such income. Net investment income, however, generally does not include gains attributable to the disposition of property held for investment or (if applicable) qualified dividend income. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, a unitholder's share of our portfolio income will be treated as investment income.

Prospective unitholders should consult their tax advisors regarding the impact of the foregoing interest deduction limitations on an investment in our common units.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the unitholder on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of common units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the unitholders in accordance with their percentage interests in us. If we have a net loss, that loss will be allocated to the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts, as adjusted for certain items in accordance with applicable Treasury Regulations.

Specified items of our income, gain, loss and deduction will be allocated to account for (i) any difference between the tax basis and fair market value of our assets at the time of this offering and (ii) any difference between the tax basis and fair market value of any property contributed to us that exists at the time of such contribution, together referred to in this discussion as the "Contributed Property." The effect of these allocations, referred to as "Section 704(c) Allocations," to a unitholder purchasing common units from us in this offering will be essentially the same as if the tax bases of our assets were equal to their fair market values at the time of this offering. In the event we issue additional common units or engage in certain other transactions in the future, "reverse Section 704(c) Allocations," similar to the Section 704(c) Allocations described above, will be made to all of our unitholders immediately prior to such issuance or other transactions to account for the difference between the "book" basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of such issuance or future transaction. However, it may not be administratively feasible to make the relevant adjustments to "book" basis and the relevant reverse Section 704(c) Allocations each time we issue common units, particularly in the case of small or frequent common unit issuances. If that is the case, we may use simplifying conventions to make those adjustments and allocations, which may include the aggregation of certain issuances of common units. Kirkland & Ellis LLP is unable to opine as to the validity of such conventions. In addition, items of recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts (subject to certain adjustments), if negative capital accounts (subject to certain adjustments) nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate such negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity," will generally be given effect for U.S. federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has "substantial economic effect." In any other case, a partner's share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Kirkland & Ellis LLP is of the opinion that, with the exception of the issues described in "— Section 754 Election" and "— Disposition of Common Units — Allocations Between Transferors and Transferees," allocations under our partnership agreement will be given effect for U.S. federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he 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. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those common units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those common units would be fully taxable; and
- while not entirely free from doubt, all of these distributions would appear to be ordinary income.

Because there is no direct or indirect controlling authority on the issue relating to partnership interests, Kirkland & Ellis LLP has not rendered an opinion regarding the tax treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their common units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read "— Disposition of Common Units — Recognition of Gain or Loss."

Tax Rates

Currently, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 37% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than twelve months) of individuals is 20%. Such rates are subject to change by new legislation at any time.

In addition, a 3.8% Medicare tax, or NIIT, is imposed on certain net investment income earned by individuals, estates and trusts. For these purposes, net investment income generally includes both a unitholder's allocable share of our income and a unitholder's gain realized upon a sale of common units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income or (ii) the amount by which the unitholder's modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if the unitholder is married and filing separately) or $200,000 (in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (i) the estate or trust's "undistributed net investment income," or (ii) the excess (if any) of the estate or trust's adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins for such taxable year. Prospective unitholders are urged to consult with their tax advisors as to the impact of the NIIT on an investment in our common units.

For taxable years beginning on or before December 31, 2025, a non-corporate unitholder is entitled to a deduction equal to 20% of its "qualified business income" attributable to us, subject to certain limitations. For purposes of this deduction, a unitholder's "qualified business income" attributable to us is equal to the sum of:

- the net amount of such unitholder's allocable share of certain of our items of income, gain, deduction and loss (generally excluding certain items related to our investment activities, such as capital gains and dividends, which are subject to a U.S. federal income tax rate of 20%); and
- any gain recognized by such unitholder on the disposition of its common units, or the deemed disposition of its common units (as described above under "— Tax Consequences of Unit Ownership — Treatment of Distributions"), to the extent such gain is attributable to certain Section 751 assets, including depreciation recapture and "inventory items" we own.

Prospective unitholders should consult their tax advisors regarding the application of this deduction and its interaction with the overall deduction for qualified business income.

Section 754 Election

We have made the election permitted by Section 754 of the Code. That election is irrevocable without the consent of the IRS. The election generally permits us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Code to reflect his purchase price. This election does not apply with respect to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, the inside basis in our assets with respect to a unitholder will be considered to have two components: (i) his share of our tax basis in our assets ("common basis") and (ii) his Section 743(b) adjustment to that basis.

We have adopted or will adopt the remedial allocation method as to all our properties. Where the remedial allocation method is adopted, the Treasury Regulations under Section 743 of the Code require a portion of the Section 743(b) adjustment that is attributable to recovery property that is subject to depreciation under Section 168 of the Code and whose book basis is in excess of its tax basis to be depreciated over the remaining cost recovery period for the property's unamortized Book-Tax Disparity. Under Treasury Regulations Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, our general partner is authorized to take a position to preserve the uniformity of common units even if that position is not consistent with these and any other Treasury Regulations. Please read "— Uniformity of Units."

We will depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as non-amortizable to the extent attributable to property that is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulations Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring common units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read "— Uniformity of Units." A unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate such unitholder's basis in his common units, which may cause the unitholder to understate gain or overstate loss on any sale of such common units. Please read "— Disposition of Common Units — Recognition of Gain or Loss." Kirkland & Ellis LLP is unable to opine as to whether our method for taking into account Section 743 adjustments is sustainable for property subject to depreciation under Section 167 of the Code or if we use an aggregate approach as described above, as there is no direct or indirect controlling authority addressing the validity of these positions. Moreover, the IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the common units. If such a challenge were sustained, the gain from the sale of common units might be increased without the benefit of additional deductions.

Subject to certain limitations, a Section 743(b) adjustment may create additional depreciable basis that is eligible for bonus depreciation under Section 168(k) to the extent the adjustment is attributable to depreciable property and not to goodwill or real property. However, because we may not be able to determine whether transfers of our common units satisfy all of the eligibility requirements and due to other limitations regarding administrability, we may elect out of the bonus depreciation provisions of Section 168(k) with respect to basis adjustments under Section 743(b).

A Section 754 election is advantageous if the transferee's tax basis in his common units is higher than the common units' share of the aggregate tax basis of our assets immediately prior to the transfer. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his common units is lower than those common units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the common units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer. Generally, a built-in loss is substantial if (i) it exceeds $250,000 or (ii) the transferee would be allocated a net loss in excess of $250,000 on a hypothetical sale of our assets for their fair market value immediately after a transfer of the interests at issue. In addition, a basis adjustment is required regardless of whether a Section 754 election is made if we distribute property and have a substantial basis reduction. A substantial basis reduction exists if, on a liquidating distribution of property to a unitholder, there would be a negative basis adjustment to our assets in excess of $250,000 if a Section 754 election were in place.

The calculations involved in the Section 754 election are complex and will be made on the basis of certain assumptions as to the value of our assets and other matters. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of common units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We will use the year ending December 31 as our taxable year and the accrual method of accounting for U.S. federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his common units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than twelve months of our income, gain, loss and deduction. Please read "— Disposition of Common Units — Allocations Between Transferors and Transferees."

Depletion Deductions

Subject to the limitations on deductibility of losses discussed above (please read "— Tax Consequences of Unit Ownership — Limitations on Deductibility of Losses"), unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and natural gas interests. Although the Code requires each unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our unitholders with information relating to this computation for U.S. federal income tax purposes. Each unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the underlying property for depletion and other purposes.

Percentage depletion is generally available with respect to unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Code. To qualify as an "independent producer" eligible for percentage depletion (and that is not subject to the intangible drilling and development cost deduction limits, please read "— Deductions for Intangible Drilling and Development Costs"), a unitholder, either directly or indirectly through certain related parties, may not be involved in the refining of more than 75,000 barrels of oil (or the equivalent amount of natural gas) on average for any day during the taxable year or in the retail marketing of oil and natural gas products exceeding $5.0 million per year in the aggregate. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the unitholder's gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the unitholder from the property for each taxable year, computed without the depletion allowance. A unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the unitholder's average net daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000-barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a unitholder's total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, capital loss carrybacks, or any deduction allowable under Section 199A of the Code. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the unitholder's total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

Unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the unitholder's share of the adjusted tax basis in the underlying mineral property by the number of mineral common units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral common units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the unitholder's share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the unitholder of some or all of his common units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the tax basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury Regulations relating to the availability and calculation of depletion deductions by the unitholders. Further, because depletion is required to be computed separately by each unitholder and not by our partnership, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the unitholders for any taxable year. Moreover, the availability of percentage depletion may be reduced or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read "— Recent Legislative Developments." We encourage each prospective unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Deductions for Intangible Drilling and Development Costs

We will elect to currently deduct intangible drilling and development costs ("IDCs"). IDCs generally include our expenses for wages, fuel, repairs, hauling, supplies and other items that are incidental to, and necessary for, the drilling and preparation of wells for the production of oil, natural gas, or geothermal energy. The option to currently deduct IDCs applies only to those items that do not have a salvage value.

Although we will elect to currently deduct IDCs, each unitholder will have the option of either currently deducting IDCs or capitalizing all or part of the IDCs and amortizing them on a straight-line basis over a 60-month period, beginning with the taxable month in which the expenditure is made. If a non-corporate unitholder makes the election to amortize the IDCs over a 60-month period, no IDC preference amount in respect of those IDCs will result for alternative minimum tax purposes.

Integrated oil companies must capitalize 30% of all their IDCs (other than IDCs paid or incurred with respect to oil and natural gas wells located outside of the United States) and amortize these IDCs over 60 months beginning in the month in which those costs are paid or incurred. If the taxpayer ceases to be an integrated oil company, it must continue to amortize those costs as long as it continues to own the property to which the IDCs relate. An "integrated oil company" is a taxpayer that has economic interests in oil or natural gas properties and also carries on substantial retailing or refining operations. An oil or natural gas producer is deemed to be a substantial retailer or refiner if it is does not qualify as an independent producer under the rules disqualifying retailers and refiners from taking percentage depletion. Please read "— Depletion Deductions."

IDCs previously deducted that are allocable to property (directly or through ownership of an interest in a partnership) and that would have been included in the adjusted tax basis of the property had the IDC deduction not been taken are recaptured to the extent of any gain realized upon the disposition of the property or upon the disposition by a unitholder of interests in us. Recapture is generally determined at the unitholder level. Where only a portion of the recapture property is sold, any IDCs related to the entire property are recaptured to the extent of the gain realized on the portion of the property sold. In the case of a disposition of an undivided interest in a property, a proportionate amount of the IDCs with respect to the property is treated as allocable to the transferred undivided interest to the extent of any gain recognized. Please read "— Disposition of Common Units — Recognition of Gain or Loss."

The election to currently deduct IDCs may be restricted or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read "— Recent Legislative Developments."

Lease Acquisition Costs

The cost of acquiring oil and natural gas leases or similar property interests is a capital expenditure that must be recovered through depletion deductions if the lease is productive. If a lease is proved worthless and abandoned, the cost of acquisition less any depletion claimed may be deducted as an ordinary loss in the year the lease becomes worthless. Please read "— Depletion Deductions."

Geophysical Costs

The cost of geophysical exploration incurred in connection with the exploration and development of oil and natural gas properties in the United States are deducted ratably over a 24-month period beginning on the date that such expense is paid or incurred. The amortization period for certain geological and geophysical expenditures may be extended if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read "— Recent Legislative Developments."

Operating and Administrative Costs

Amounts paid for operating a producing well are deductible as ordinary business expenses, as are administrative costs, to the extent they constitute ordinary and necessary business expenses that are reasonable in amount.

Tax Basis, Depreciation and Amortization

The tax basis of our assets will be used for purposes of computing depreciation, depletion, amortization, accretion and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The U.S. federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to an offering will be borne by our unitholders holding interests in us prior to any such offering. Please read "— Tax Consequences of Unit Ownership — Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may use the depreciation and cost recovery methods, including bonus depreciation to the extent available, that will result in the largest deductions being taken in the early years after assets subject to these allowances are placed in service. Please read "— Uniformity of Units." Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Code.

If we dispose of depreciable or depletable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation and depletion previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery, depletion or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read "— Tax Consequences of Unit Ownership — Allocation of Income, Gain, Loss and Deduction" and "— Disposition of Common Units — Recognition of Gain or Loss."

The costs we incur in selling our common units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of our Properties

The U.S. federal income tax consequences of the ownership and disposition of common units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or determinations of basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of common units equal to the difference between the amount realized and the unitholder's tax basis in the common units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of common units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us that in the aggregate were in excess of cumulative net taxable income for a common unit and, therefore, decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in common units, on the sale or exchange of a common unit will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of common units held for more than twelve months will generally be taxed at the U.S. federal income tax rate applicable to long-term capital gains. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Code to the extent attributable to (i) "unrealized receivables," including potential recapture items such as depreciation, depletion, amortization and accretion expenses or IDCs, or (ii) "inventory items" we own. Ordinary income attributable to unrealized receivables and inventory items may exceed net taxable gain realized upon the sale of a common unit and may be recognized even if there is a net taxable loss realized on the sale of a common unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of common units. Capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations. Ordinary income recognized by a non-corporate unitholder on disposition of our common units may be reduced by such unitholder's deduction for qualified business income. Both ordinary income and capital gain recognized on a sale of common units may be subject to the NIIT in certain circumstances. Please read "— Tax Consequences of Unit Ownership — Tax Rates."

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling discussed above, a unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, he may designate specific common units sold for purposes of determining the holding period of common units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. Unitholders considering the purchase of additional common units or a sale of common units purchased in separate transactions should consult their tax advisors as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest — that is, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value — if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract;

in each case, with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position. Prospective unitholders should consult their tax advisors regarding the impact of these constructive sale rules in connection with an investment in our common units.

Allocations between Transferors and Transferees

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis in proportion to the number of days in each month and will be subsequently apportioned among our unitholders in proportion to the number of common units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among our unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring common units may be allocated income, gain, loss and deduction realized after the date of transfer.

The U.S. Department of Treasury and the IRS have issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. Accordingly, Kirkland & Ellis LLP is unable to opine on the validity of this method of allocating income and deductions between transferor and transferee unitholders. If this method is not allowed under the Treasury Regulations, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferor and transferee unitholders, as well as unitholders whose interests vary during a taxable year.

A unitholder who owns common units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter through the month of disposition but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his common units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of common units who purchases common units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker who will satisfy such requirements.

Uniformity of Units

Because we cannot match transferors and transferees of common units, we must maintain uniformity of the economic and tax characteristics of the common units to a purchaser of these common units. In the absence of uniformity, we may be unable to completely comply with a number of U.S. federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulations Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the common units. Please read "— Tax Consequences of Unit Ownership — Section 754 Election."

We will depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as non-amortizable to the extent attributable to property that is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulations Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read "— Tax Consequences of Unit Ownership — Section 754 Election." To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring common units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any common units that would not have a material adverse effect on the unitholders. In either case, and as stated above under "— Tax Consequences of Unit Ownership — Section 754 Election," Kirkland & Ellis LLP has not rendered an opinion with respect to these methods. Moreover, the IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of common units might be affected, and the gain from the sale of common units might be increased without the benefit of additional deductions. Please read "— Disposition of Common Units — Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of common units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below to a limited extent, may have substantially adverse tax consequences to them. If you are such an investor, you should consult your own tax advisor before investing in our common units.

Employee benefit plans and most other organizations exempt from U.S. federal income tax, including IRAs and other retirement plans, are subject to U.S. federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it. Further, a tax-exempt organization with more than one unrelated trade or business (including by attribution from investments in a partnership, such as us, that is engaged in one or more unrelated trades or businesses) must compute its unrelated business taxable income separately for 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 organizations to use losses from an investment in us to offset taxable income from another unrelated trade or business.

Non-resident aliens and foreign corporations, trusts or estates that own common units will be considered to be engaged in business in the United States because of the ownership of common units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay U.S. federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, our quarterly distribution to foreign unitholders will be subject to withholding at the highest applicable marginal tax rate. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN, W-8BEN-E or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns common units will be treated as engaged in a U.S. trade or business, that corporation may be subject to the U.S. branch profits tax at a rate of 30%, in addition to regular U.S. federal income tax, on its share of our earnings and profits, as adjusted for changes in the foreign corporation's "U.S. net equity," that are effectively connected with the conduct of a U.S. trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Code.

A foreign unitholder who sells or otherwise disposes of a common unit will be subject to U.S. federal income tax on gain realized from the sale or disposition of that common unit to the extent the gain is effectively connected with a U.S. trade or business of the foreign unitholder. Gain on the sale or disposition of a common unit will be treated as effectively connected with a U.S. trade or business to the extent that a foreign unitholder would recognize gain effectively connected with a U.S. trade or business upon the hypothetical sale of our assets at fair market value on the date of the sale or exchange of that common unit. Such gain shall be reduced by certain amounts treated as effectively connected with a U.S. trade or business attributable to certain real property interests, as set forth in the following paragraph.

Under the Foreign Investment in Real Property Tax Act, a foreign unitholder (other than certain "qualified foreign pension funds" (or an entity all of the interests of which are held by such a qualified foreign pension fund), which generally are entities or arrangements that are established and regulated by foreign law to provide retirement or other pension benefits to employees, do not have a single participant or beneficiary that is entitled to more than 5% of the assets or income of the entity or arrangement and are subject to certain preferential tax treatment under the laws of the applicable foreign country), generally will be subject to U.S. federal income tax upon the sale or disposition of a common unit if (i) he owned (directly or constructively applying certain attribution rules) more than 5% of our common units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such unitholder held the common units or the five-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests and we do not expect that to change in the foreseeable future.

Therefore, foreign unitholders may be subject to U.S. federal income tax on gain from the sale or disposition of their common units.

Upon the sale, exchange or other disposition of a common unit by a foreign 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. Quarterly distributions made to our foreign unitholders may also be subject to 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. Prospective foreign unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

Additional withholding requirements may also affect certain foreign unitholders. Please read "— Administrative Matters — Additional Withholding Requirements."

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Kirkland & Ellis LLP can assure prospective unitholders that the IRS will not successfully contend that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the common units.

A unitholder must file a statement with the IRS identifying the treatment of any item on his U.S. federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

The IRS may audit our U.S. federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Similarly, if the IRS makes audit adjustments to income tax returns filed by an entity in which we are a member or a partner, it may assess and collect any taxes (including penalties and interest) resulting from such audit adjustment directly from such entity. Generally, we expect to elect to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be effective in all circumstances. If we are unable to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our common units 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.

Additionally, pursuant to the Bipartisan Budget Act of 2015, we are required to designate a partner, or other person, with a substantial presence in the United States as the partnership representative ("Partnership Representative"). The Partnership Representative has the sole authority to act on our behalf for purposes of, among other situations, U.S. federal income tax audits and judicial review of administrative adjustments by the IRS. If we do not make such a designation, the IRS can select any person as the Partnership Representative. We currently anticipate that we will designate our general partner as our Partnership Representative. Further, any actions taken by us or by the Partnership Representative on our behalf with respect to, among other situations, U.S. federal income tax audits and judicial review of administrative adjustments by the IRS, will be binding on us and all of our unitholders.

Additional Withholding Requirements

Withholding taxes may apply to certain types of payments made to "foreign financial institutions" (as specifically defined in the Code) and certain other foreign entities. Specifically, a 30% withholding tax may be imposed on interest, dividends and other fixed or determinable annual or periodical gains, profits and income from sources within the United States ("FDAP Income"), or, subject to the proposed Treasury Regulations discussed below, gross proceeds from the sale or other disposition of any property of a type that can produce interest or dividends from sources within the United States ("Gross Proceeds") paid to a foreign financial institution or to a “non-financial foreign entity” (as specifically defined in the Code), unless (i) the foreign financial institution undertakes certain diligence and reporting, (ii) the non-financial foreign entity either certifies it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. If the payee is a foreign financial institution and is subject to the diligence and reporting requirements in clause (i) above, it must enter into an agreement with the U.S. Department of the Treasury requiring, among other obligations, that it undertake to identify accounts held by certain U.S. persons or U.S.-owned foreign entities, annually report certain information about such accounts, and withhold 30% on payments to noncompliant foreign financial institutions and certain other account holders. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing these requirements may be subject to different rules.

These rules generally apply to payments of FDAP Income currently and, while these rules generally would have applied to payments of relevant Gross Proceeds made on or after January 1, 2019, proposed Treasury Regulations eliminate these withholding taxes on payments of Gross Proceeds entirely. Unitholders generally may rely on these proposed Treasury Regulations until final Treasury Regulations are issued. Thus, to the extent we have FDAP Income that is not treated as effectively connected with a U.S. trade or business (please read “— Tax-Exempt Organizations and Other Investors”), unitholders who are foreign financial institutions or certain other foreign entities, or persons that hold their common units through such foreign entities, may be subject to withholding on distributions they receive from us, or their distributive share of our income, pursuant to the rules described above.

Prospective unitholders should consult their own tax advisors regarding the potential application of these withholding provisions to their investment in our common units.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

1. the name, address and taxpayer identification number of the beneficial owner and the nominee;
2. whether the beneficial owner is:
   a. a person that is not a U.S. person;
   b. a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or
   c. a tax-exempt entity;
3. the amount and description of units held, acquired or transferred for the beneficial owner; and
4. specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition costs for purchases, as well as the amount of net proceeds from dispositions.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on common units they acquire, hold or transfer for their own account. A penalty of $290 per failure, up to a maximum of $3,532,500 per calendar year, is imposed by the Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the common units with the information furnished to us.

Accuracy-Related Penalties

Certain penalties may be imposed on taxpayers as a result of an underpayment of tax that is attributable to one or more specified causes, including: (i) negligence or disregard of rules or regulations, (ii) substantial understatements of income tax, (iii) substantial valuation misstatements and (iv) the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law. Except with respect to the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law, however, no penalty will be imposed for any portion of any such underpayment if it is shown that there was a reasonable cause for the underpayment of that portion and that the taxpayer acted in good faith regarding the underpayment of that portion.

With respect to substantial understatements of income tax, the amount of any understatement subject to penalty generally is reduced by that portion of the understatement which is attributable to a position adopted on the return: (A) for which there is or was “substantial authority”; or (B) as to which there is a reasonable basis and the relevant facts are adequately disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an “understatement” of income for which no “substantial authority” exists, we must adequately disclose the relevant facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty.

Recent Legislative Developments

The present U.S. 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 at any time. For example, from time to time, members of Congress and the President propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships.

In recent years, legislation has been proposed that would reduce or eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Changes in such proposals 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 common units.

Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. Please read “— Partnership Status”. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

State, Local, Foreign and Other Tax Considerations

In addition to U.S. federal income taxes, you will likely be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We expect initially to own property or do business in Oklahoma, Kansas and Texas. Oklahoma and Kansas 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 income tax. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some of the jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder’s income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read “— Tax Consequences of Unit Ownership — Entity-Level Collections.” Based on current law and our estimate of our future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of the United States, pertinent states, localities and foreign jurisdictions, of his investment in us. Accordingly, each prospective unitholder should consult his own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as U.S. federal tax returns, that may be required of him. Kirkland & Ellis LLP has not rendered an opinion on the state tax, local tax, alternative minimum tax or non-U.S. tax consequences of an investment in us.

INVESTMENT IN MACH NATURAL RESOURCES BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and the restrictions imposed by Section 4975 of the Internal Revenue Code and provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Internal Revenue Code or ERISA (collectively, "Similar Laws"). For these purposes the term "employee benefit plan" includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization, and entities whose underlying assets are considered to include "plan assets" of such plans, accounts and arrangements (collectively, "Employee Benefit Plans"). Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;
- whether in making the investment, the plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please read "Material U.S. Federal Income Tax Consequences — Tax-Exempt Organizations and Other Investors"; and
- whether making such an investment will comply with the delegation of control and prohibited transaction provisions of ERISA, the Internal Revenue Code and any other applicable Similar Laws.

The person with investment discretion with respect to the assets of an Employee Benefit Plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit Employee Benefit Plans, and IRAs that are not considered part of an Employee Benefit Plan, from engaging, either directly or indirectly, in specified transactions involving "plan assets" with parties that, with respect to the plan, are "parties in interest" under ERISA or "disqualified persons" under the Internal Revenue Code unless an exemption is available. A party in interest or disqualified person who engages in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Internal Revenue Code. In addition, the fiduciary of the ERISA plan that engaged in such a non-exempt prohibited transaction may be subject to penalties and liabilities under ERISA and the Internal Revenue Code.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our general partner would also be a fiduciary of such plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code, ERISA and any other applicable Similar Laws.

The Department of Labor regulations and Section 3(42) of ERISA provide guidance with respect to whether, in certain circumstances, the assets of an entity in which Employee Benefit Plans acquire equity interests would be deemed "plan assets." Under these rules, an entity's assets would not be considered to be "plan assets" if, among other things:

- the equity interests acquired by the Employee Benefit Plan are publicly offered securities — i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, are freely transferable and are registered under certain provisions of the federal securities laws;
- the entity is an "operating company," — i.e., it is primarily engaged in the production or sale of a product or service, other than the investment of capital, either directly or through a majority-owned subsidiary or subsidiaries; or
- there is no significant investment by "benefit plan investors," which is generally defined to mean that less than 25% of the value of each class of equity interest, disregarding any such interests held by our general partner, its affiliates and certain persons, is held by the Employee Benefit Plans.

Our assets should not be considered “plan assets” under these regulations because it is expected that the investment will satisfy the requirements in the first two bullet points above.

In light of the serious penalties imposed on persons who engage in prohibited transactions or other violations, plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA, the Internal Revenue Code and other Similar Laws.

UNDERWRITING

Stifel, Nicolaus & Company, Incorporated and Raymond James & Associates, Inc. are acting as representatives of each of the underwriters named below. Subject to the terms and conditions set forth in an underwriting agreement dated the date of this prospectus, we have agreed to sell to the underwriters, and each of the underwriters has agreed, severally and not jointly, to purchase from us, the number of our common units set forth opposite its name below.

Underwriters	Number of Common Units
Stifel, Nicolaus & Company, Incorporated	
Raymond James & Associates, Inc.	
Total	

Subject to the terms and conditions set forth in the underwriting agreement, the underwriters have agreed, severally and not jointly, to purchase all of our common units (other than those covered by the underwriters' option to purchase additional common units described below) sold under the underwriting agreement. If an underwriter defaults, the underwriting agreement provides that the purchase commitments of the non-defaulting underwriters may be increased or the underwriting agreement may be terminated.

We have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make in respect of those liabilities.

The underwriters are offering our common units, subject to prior sale, when, as and if issued to and accepted by them, subject to approval of legal matters by their counsel, including the validity of the common units, and other conditions contained in the underwriting agreement, such as the receipt by the underwriters of officers' certificates and legal opinions. The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or in part.

Underwriting Discounts and Expenses

The representatives have advised us that the underwriters propose initially to offer our common units to the public at the public offering price set forth on the cover page of this prospectus and to dealers at that price less a concession not in excess of $ per common unit. After this offering, the public offering price, concession or any other term of this offering may be changed.

The following table shows the public offering price, underwriting discount and proceeds before expenses to us. The information assumes either no exercise or full exercise by the underwriters of their option to purchase additional common units.

	Per Unit	Without Option	With Option
Public offering price	$	$	$
Underwriting discount	$	$	$
Proceeds, before expenses, to us	$	$	$

The estimated expenses of this offering payable by us, exclusive of the underwriting discount, are approximately $. The underwriting discount includes a structuring fee we will pay to Stifel, Nicolaus & Company, Incorporated and Raymond James & Associates, Inc. equal to % of the gross proceeds of this offering (including upon exercise of the underwriters' option to purchase additional common units) for the evaluation, analysis and structuring of the partnership. We will reimburse the underwriters for certain reasonable out-of-pocket expenses (including those related to background checks, blue sky laws and the review by the Financial Industry Regulatory Authority ("FINRA") of the terms of sale of the common units offered hereby) not to exceed $ in the aggregate.

Over-Allotment Option

We have granted an option to the underwriters to purchase up to an aggregate of additional common units at the public offering price, less the underwriting discount. The underwriters may exercise this option at any time or from time to time for 30 days from the date of this prospectus solely to cover any over-allotments.

If the underwriters exercise this option, each will be obligated, subject to conditions contained in the underwriting agreement, to purchase a number of additional common units proportionate to that underwriter's initial amount as reflected in the above table.

No Sales of Similar Securities

The Sponsor, the directors and executive officers of our general partner have agreed with the underwriters not to offer, sell, transfer or otherwise dispose of any common units or any securities convertible into or exercisable or, exchangeable for, exercisable for, or repayable with common units, for a period of 180 days after the date of this prospectus without first obtaining the written consent of the representatives. Specifically, we and these other persons have agreed, with certain limited exceptions, not to directly or indirectly:

- offer, pledge, sell or contract to sell any common units;
- sell any option or contract to purchase any common units;
- purchase any option or contract to sell any common units;
- grant any option, right or warrant for the sale of any common units;
- lend or otherwise dispose of or transfer any common units;
- file or cause to be filed any registration statement related to the common units; or
- enter into any swap hedging, collar or other agreement that can be reasonably expected to transfer, in whole or in part, the economic consequence of ownership of any common units whether any such swap hedging, collar or other agreement is to be settled by delivery of common units or other securities, in cash or otherwise.

This lock-up provision applies to common units and to securities convertible into or exchangeable or exercisable for or repayable with common units. It also applies to common units owned now or acquired later by the person executing the agreement or for which the person executing the agreement later acquires the power of disposition.

Stifel, Nicolaus & Company, Incorporated and Raymond James & Associates, Inc. may release any of the common units and other securities subject to the lock-up agreements described above in whole or in part subject to the below considerations. When determining whether or not to release common units from lock-up agreements, Stifel, Nicolaus & Company, Incorporated and Raymond James & Associates, Inc. will consider, among other factors, the unitholders' reasons for requesting the release, the number of common units for which the release is being requested and market conditions at the time. However, Stifel, Nicolaus & Company, Incorporated and Raymond James & Associates, Inc. have informed us that, as of the date of this prospectus, there are no agreements between them and any party that would allow such party to transfer any common units, nor do they have any intention at this time of releasing any of the common units subject to the lock-up agreements, prior to the expiration of the lock-up period.

Listing

We intend to list our common units on the NYSE under the symbol "MNRE." In order to meet the requirements for listing on that exchange, the underwriters will undertake to sell a minimum number of our common units to a minimum number of beneficial owners as required by the NYSE.

Determination of Offering Price

Before this offering, there has been no public market for our common units. The public offering price will be determined through negotiations between us and the representatives. In addition to prevailing market conditions, the factors to be considered in determining the public offering price are:

- the information set forth in this prospectus and otherwise available to the underwriters;
- the valuation multiples of publicly traded companies that the representatives believe to be comparable to us;

- our financial information;
- the history of, and the prospects for, our company and the industry in which we compete;
- the ability of our management;
- an assessment of our general partner, its past and present operations, and the prospects for, and timing of, our future revenues;
- the present state of our development;
- the above factors in relation to market values and various valuation measures of other companies engaged in activities similar to ours; and
- other factors deemed relevant by the underwriters and us.

An active trading market for our common units may not develop or, if developed, be maintained or be liquid. It is also possible that after this offering our common units will not trade in the public market at or above the public offering price.

The underwriters do not expect to sell more than 5% of the common units in the aggregate to accounts over which they exercise discretionary authority.

Price Stabilization, Short Positions and Penalty Bids

Until the distribution of our common units is completed, SEC rules may limit underwriters and selling group members from bidding for and purchasing our common units. However, the underwriters may engage in transactions that stabilize the price of the common units, such as bids or purchases to peg, fix or maintain that price.

In connection with this offering, the underwriters may purchase and sell our common units in the open market. These transactions may include short sales, purchases on the open market to cover positions created by short sales and stabilizing transactions. Short sales involve the sale by the underwriters of a greater number of our common units than they are required to purchase in this offering. "Covered" short sales are sales made in an amount not greater than the underwriters' over-allotment option to purchase additional common units described above. The underwriters may close out any covered short position by either exercising their option or purchasing common units in the open market. In determining the source of our common units to close out the covered short position, the underwriters will consider, among other things, the price of our common units available for purchase in the open market as compared to the price at which they may purchase our common units through the option. "Naked" short sales are sales in excess of the over-allotment option. The underwriters must close out any naked short position by purchasing our common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of our common units in the open market after pricing that could adversely affect investors who purchase in this offering. Stabilizing transactions consist of various bids for or purchases of our common units made by the underwriters in the open market prior to the completion of this offering.

The underwriters may also impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the underwriters have repurchased common units sold by or for the account of such underwriter in stabilizing or short covering transactions.

Similar to other purchase transactions, the underwriters' purchases to cover the syndicate short sales may have the effect of raising or maintaining the market price of our common units or preventing or retarding a decline in the market price of our common units. As a result, the price of our common units may be higher than the price that might otherwise exist in the open market. The underwriters may conduct these transactions on the NYSE, in the over-the-counter market or otherwise.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of our common units. In addition, neither we nor any of the underwriters make any representation that the underwriters will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Electronic Distribution

In connection with this offering, certain of the underwriters or securities dealers may distribute prospectuses by electronic means, such as e-mail. In addition, the underwriters may facilitate Internet distribution for this offering to certain of their Internet subscription customers. The underwriters may allocate a limited number of our common units for sale to their online brokerage customers. An electronic prospectus may be available on the websites maintained by the underwriters. Other than the prospectus set forth in electronic format, the information on the underwriters' websites is not part of this prospectus.

Other Relationships

In addition, in the ordinary course of their business activities, the underwriters and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates. The underwriters and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Direct Participation Program Requirements

Because FINRA views the common units offered hereby as interests in a direct participation program, the offering is being made in compliance with FINRA Rule 2310. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

VALIDITY OF THE COMMON UNITS

The validity of the common units and certain tax matters will be passed upon for us by Kirkland & Ellis LLP, Houston, Texas. Certain legal matters in connection with the common units offered by us will be passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

The audited consolidated financial statements of BCE-Mach III LLC as of and for the years ended December 31, 2022 and 2021 included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the report of Grant Thornton LLP, independent registered public accountants, upon the authority of said firm as experts in accounting and auditing.

The audited financial statements of BCE-Mach LLC as of and for the years ended December 31, 2022 and 2021 included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the report of Grant Thornton LLP, independent certified public accountants, upon the authority of said firm as experts in accounting and auditing.

The audited financial statements of BCE-Mach II LLC as of and for the years ended December 31, 2022 and 2021 included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the report of Grant Thornton LLP, independent certified public accountants, upon the authority of said firm as experts in accounting and auditing.

Estimated quantities of proved and probable oil and natural gas reserves of the Mach Companies and the net present value of such reserves as of June 30, 2023 and proved oil and natural gas reserves of the Mach Companies and the net present value of such reserves as of December 31, 2022 set forth in this prospectus are based upon reserve reports prepared by our internal reservoir engineers and evaluated by Cawley, Gillespie & Associates.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-l (including the exhibits, schedules and amendments thereto) regarding our common units. This prospectus, which constitutes part of the registration statement, does not contain all of the information set forth in the registration statement and the exhibits and schedules thereto. For further information regarding us and our common units offered in this prospectus, we refer you to the full registration statement, including its exhibits and schedules, filed under the Securities Act. Statements contained in this prospectus as to the contents of any contract, agreement or any other document are summaries of the material terms of such contract, agreement or other document and are not necessarily complete. With respect to each of these contracts, agreements or other documents filed as an exhibit to the registration statement, reference is made to the exhibits for a more complete description of the matter involved. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's website. The address of the SEC's website is *www.sec.gov*.

As a result of the offering, we will become subject to full information requirements of the Exchange Act. We intend to furnish or make available to our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information, including the information required by Form 10-Q, for the first three fiscal quarters of each of our fiscal years. Additionally, we intend to file other periodic reports with the SEC, as required by the Exchange Act.

FORWARD-LOOKING STATEMENTS

Some of the information in this prospectus may contain "forward-looking statements." All statements, other than statements of historical fact included in this prospectus 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 prospectus, 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 prospectus.

- our business strategy;
- our estimated proved reserves;
- our ability to distribute cash available for distribution and achieve or maintain certain financial and operational metrics;
- our drilling prospects, inventories, projects and programs;
- general economic conditions, including the effects of a global health crises such as the COVID-19 pandemic;
- actions taken by OPEC + as it pertains to the global supply and demand of, and prices for, oil, natural gas and NGLs;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, leverage, liquidity and capital required for our development program;
- our pending legal or environmental matters;
- our realized oil and natural gas prices;
- the timing and amount of our future production of natural gas;
- our ability to reduce or offset our GHG emissions, including our ability to achieve carbon neutrality;
- our hedging strategy and results;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our marketing of natural gas;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- credit markets;
- our decline rates of our oil and gas properties;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this prospectus that are not historical.

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 prospectus. 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 Anadarko 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;
- any downgrades in our credit ratings that could negatively impact our cost of and ability to access capital;
- 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 war 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, insiders 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 prospectus 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 prospectus 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 prospectus.

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MACH NATURAL RESOURCES LP
Pro Forma Condensed Consolidated Financial Statements
(Unaudited)
(in thousands)

Introduction

Mach Natural Resources LP (the "Company") is a limited partnership focused on the acquisition, development, and production of oil, natural gas and NGL reserves in the Anadarko Basin region of Western, Oklahoma, Southern Kansas and the panhandle of Texas. The unaudited pro forma financial statements have been prepared in accordance with Article 11 of Regulation S-X, using assumptions set forth in the notes to the unaudited pro forma financial statements. The following unaudited pro forma financial statements of the Company reflect the historical results of BCE-Mach III LLC ("Predecessor"), BCE-Mach LLC and BCE-Mach II LLC on a pro forma basis to give effect to the following transactions, which are described in further detail below, as if they had occurred on June 30, 2023, for pro forma balance sheet purposes, and on January 1, 2022, for pro forma statements of operations purposes:

1. The Reorganization Transactions as described in "Prospectus Summary — Reorganization Transactions and Partnership Structure" elsewhere in this prospectus; and
2. The initial public offering of common units and use of the net proceeds therefrom as described in "Use of Proceeds" (the "Offering"). For purposes of the unaudited pro forma financial statements, the Offering is defined as the planned issuance and sale to the public of common units of the Company at an assumed initial public offering price of $ per common unit as contemplated by this prospectus and the application by the Company of the net proceeds from such issuance as described in "Use of Proceeds." The net proceeds from the sale of the common units are expected to be $, net of underwriting discounts of $ and other offering costs of $.

   Contemporaneously with the closing of the Offering, we expect to use the proceeds of the Offering to pay down the balances of the Existing Credit Facilities. We also expect to enter into a New Credit Facility contemporaneously with the closing of the Offering. The New Credit Facility (under which no amounts will be outstanding at the closing of the Offering) is expected to have a total facility size of $ million, an initial borrowing base of $ million and available capacity of $ million.

The unaudited pro forma balance sheet of the Company is based on the historical balance sheets of BCE-Mach III LLC, BCE-Mach LLC and BCE-Mach II LLC, as of June 30, 2023, and includes pro forma adjustments to give effect to the described transactions as if they had occurred on June 30, 2023. The unaudited pro forma statements of operations of the Company are based on the audited historical statement of operations of BCE-Mach III LLC, BCE-Mach LLC and BCE-Mach II LLC for the year ended December 31, 2022, and for the six months ended June 30, 2023, and all having been adjusted to give effect to the described transactions as if they occurred on January 1, 2022. All entities to be contributed in the Reorganization Transactions have a high degree of common ownership, though no individual controls any of the entities and therefore the transactions are not accounted for as common control transactions, and the acquisition of BCE-Mach and BCE-Mach II by BCE-Mach III will be accounted for in accordance with the business combination guidance in ASC 805.

The pro forma data presented reflect events directly attributable to the described transactions and certain assumptions the Company believes are reasonable. The pro forma data is not necessarily indicative of financial results that would have been attained had the described transactions occurred on the date indicated or which could be achieved in the future because they necessarily exclude various operating expenses, such as incremental general and administrative expenses associated with being a public company. The adjustments are based on currently available information and certain estimates and assumptions. Therefore, the actual adjustments may differ from the pro forma adjustments. However, management believes that the assumptions provide a reasonable basis for presenting the significant effects of the transactions as contemplated and the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited financial statements. The Company has not included any adjustments depicting synergies or dis-synergies of the Reorganization Transactions.

The unaudited pro forma financial statements and related notes are presented for illustrative purposes only. If the Reorganization Transactions and the Offering had occurred in the past, the Company's operating results might have been materially different from those presented in the unaudited pro forma financial statements. The unaudited pro forma financial statements should not be relied upon as an indication of operating results that the Company would have achieved if the Reorganization Transactions and the Offering had taken place on the specified date. In addition, future results may vary significantly from the results reflected in the unaudited pro forma financial statements of operations and should not be relied upon as an indication of the future results the Company will have after the contemplation of the Reorganization Transactions and the Offering.

The accompanying notes are an integral part of these unaudited pro forma financial statements.

MACH NATURAL RESOURCES LP
Pro Forma Balance Sheet
As of June 30, 2023
(Unaudited)
(in thousands)

	Historical							
	BCE-Mach III Predecessor	BCE-Mach I	BCE-Mach II	Reorganization Transaction Pro Forma Adjustments		Offering Transaction Pro Forma Adjustments		Pro Forma
ASSETS								
Current assets								
Cash and cash equivalents	$ 48,846	$ 23,441	$ 11,321	$ —		$ 26,000	(a)	$ 109,608
Accounts receivable – joint interest and other	20,093	11,860	6,823	—		—		38,776
Accounts receivable – oil, gas, and NGL sales	52,394	18,712	1,548	—		—		72,654
Inventories	20,958	13,776	1,085	—		—		35,819
Short-term derivative contracts	—	1,378	429	—		—		1,807
Other current assets	2,088	1,297	690	—		—		4,075
Total current assets	144,379	70,464	21,896	—		26,000		262,739
Oil and natural gas properties, using the full cost method:								
Proved oil and natural gas properties	939,516	527,892	81,280	(268,035)	(b)	—		1,280,653
Less: accumulated depreciation and depletion	(195,445)	(292,424)	(39,651)	332,075	(b)	—		(195,445)
Oil and natural gas properties, net	744,071	235,468	41,629	64,040		—		1,085,208
Other property, plant and equipment	87,015	98,589	11,474	(94,099)	(c)	—		102,979
Less: accumulated depreciation and impairment	(11,964)	(39,953)	(2,448)	38,150	(c)	—		(16,215)
Other property, plant and equipment, net	75,051	58,636	9,026	(55,949)		—		86,764
Other assets	2,124	4,337	169	(1,038)	(d)	—		5,592
Operating lease assets	13,687	3,196	1,145	—		—		18,028
Goodwill	—	2,674	—	(2,674)	(e)	—		—
Total assets	$ 979,312	$ 374,775	$ 73,865	$ 4,379		$ 26,000		$ 1,458,331
LIABILITIES AND EQUITY								
Current liabilities								
Accounts payable	$ 38,129	$ 6,033	$ 1,222	$ —		$ —		$ 45,384
Accrued liabilities	38,172	10,455	2,657	—		—		51,284
Revenue payable	50,569	25,796	15,839	—		—		92,204
Current portion of operating lease liabilities	10,692	1,463	426	—		—		12,581
Short-term derivative contracts	1,869	—	—	—		—		1,869
Total current liabilities	139,431	43,747	20,144			—		203,322
Long-term debt	91,900	65,000	17,100	—		(174,000)	(a)	—
Asset retirement obligations	54,592	34,445	19,028	—		—		108,065
Long-term portion of operating lease liabilities	3,176	1,740	720	—		—		5,636
Other long-term liabilities	686	274	482	—		—		1,442
Total long-term liabilities	150,354	101,459	37,330			(174,000)		115,143
Members' equity	689,527	229,569	16,391	4,379		200,000		1,139,866
Total liabilities and members' equity	$ 979,312	$ 374,775	$ 73,865	$ 4,379		$ 26,000		$ 1,458,331

The accompanying notes are an integral part of these unaudited pro forma financial statements.

MACH NATURAL RESOURCES LP
Pro Forma Statement of Operations for the Six Months Ended June 30, 2023
(Unaudited)
(in thousands)

	Historical			Reorganization Transaction Pro Forma Adjustments		Offering Transaction Pro Forma Adjustments		Pro Forma
	BCE-Mach III Predecessor	BCE-Mach I	BCE-Mach II					
Revenue								
Oil, natural gas, and NGL sales	$ 312,613	$ 70,710	$ 16,363	$ —		$ —		$ 399,686
Midstream revenue	13,318	—	213	—		—		13,531
Gain on oil and natural gas derivatives	15,742	6,048	828	—		—		22,618
Product sales	17,421	—	0	—		—		17,421
Total revenues	359,094	76,758	17,404	—		—		453,256
Operating expenses								
Gathering and processing	17,510	13,928	1,992	—		—		33,430
Lease operating expense	60,615	20,514	6,310	—		—		87,439
Midstream operating expense	5,538	—	223	—		—		5,761
Cost of product sales	15,575	—	—	—		—		15,575
Production taxes	15,526	3,644	833	—		—		20,003
Depreciation, depletion, and accretion – oil and natural gas	58,095	12,678	2,167	(823)	(f)	—		72,117
Depreciation and amortization – other	2,793	4,454	346	(4,422)	(g)	—		3,171
General and administrative	9,905	4,791	(1,536)	—		(1,410)	(h)	11,750
Total operating expenses	185,557	60,009	10,335	(5,245)		(1,410)		249,246
Income from operations	173,537	16,749	7,069	5,245		1,410		204,010
Other (expense) income								
Interest expense	(3,789)	(2,811)	(747)	—		7,347	(i)	—
Other (expense) income, net	(245)	(4,075)	(646)	—		—		(4,966)
Total other expense	(4,034)	(6,886)	(1,393)	—		7,347		(4,966)
Net income	$ 169,503	$ 9,863	$ 5,676	$ 5,245		$ 8,757		$ 199,044
Net income per Common Unit								
Basic	$							$
Diluted	$							$
Weighted Average Common Units Outstanding								
Basic								
Diluted								

The accompanying notes are an integral part of these unaudited pro forma financial statements.

MACH NATURAL RESOURCES LP
Pro Forma Statement of Operations for the Year Ended December 31, 2022
(Unaudited)
(in thousands)

	Historical							
	BCE-Mach III Predecessor	BCE-Mach I	BCE-Mach II	Reorganization Transaction Pro Forma Adjustments		Offering Transaction Pro Forma Adjustments		Pro Forma
Revenue								
Oil, natural gas, and NGL sales	$ 860,388	$ 233,644	$ 71,388	$ —		$ —		$ 1,165,420
Midstream revenue	44,373	—	459	—		—		44,832
Loss on oil and natural gas derivatives	(67,453)	(42,334)	(3,535)	—		—		(113,322)
Product sales	100,106	—	—	—		—		100,106
Total revenues	937,414	191,310	68,312	—		—		1,197,036
Operating expenses								
Gathering and processing	47,484	34,437	5,966	—		—		87,887
Lease operating expense	95,941	35,605	13,721	—		—		145,267
Midstream operating expense	15,157	—	461	—		—		15,618
Cost of product sales	94,580	—	—	—		—		94,580
Production taxes	47,825	13,246	4,123	—		—		65,194
Depreciation, depletion, and accretion – oil and natural gas	84,070	26,621	4,487	4,181	(f)	—		119,359
Depreciation and amortization – other	4,519	8,318	679	(8,071	(g)	—		5,445
General and administrative	25,454	4,577	(2,551)	—		(8,202)	(h)	19,278
Total operating expenses	415,030	122,804	26,886	(3,890)		(8,202)		552,628
Income from operations	522,384	68,506	41,426	3,890		8,202		644,408
Other (expense) income								
Interest expense	(4,852)	(5,515)	(951)	—		11,318	(i)	0
Other (expense) income, net	(691)	(452)	60	—		—		(1,083)
Loss on debt extinguishment		(898)	—	—		898	(j)	0
Total other expense	(5,543)	(6,865)	(891)	—		12,216		(1,083)
Net income	$ 516,841	$ 61,461	$ 40,535	$ 3,890		$ 20,418		$ 643,325
Net income per Common Unit								
Basic	$							$
Diluted	$							$
Weighted Average Common Units Outstanding								
Basic								

The accompanying notes are an integral part of these unaudited pro forma financial statements.

MACH NATURAL RESOURCES LP
Notes to Pro Forma Condensed Consolidated Financial Statements

1. Basis of Presentation, Corporate Reorganization and the Offering

The historical financial information is derived from the financial statements of BCE-Mach III LLC included elsewhere in this prospectus. For purposes of the audited balance sheet, it is assumed that the transaction took place on June 30, 2023. For purposes of the audited pro forma statement of operations it is assumed that the transaction took place on January 1, 2022.

Upon closing the Offering, the Company expects to incur direct, incremental general and administrative expenses as a result of being publicly traded, including, but not limited to, costs associated with annual and quarterly reports to unitholders, tax return preparation, independent auditor fees, incremental legal fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and independent director compensation. These direct, incremental general and administrative expenditures are not reflected in the historical financial statements or in the unaudited pro forma financial statements.

Prior to the closing of this offering, the following transactions, which we refer to as the reorganization transactions, will occur:

(a) Bayou City Energy, L.P. will contribute 100% of its membership interests in Predecessor, BCE-Mach LLC and BCE-Mach II LLC to BCE Mach Aggregator LLC ("BCE-Mach Aggregator") in exchange for 100% of the membership interests in BCE-Mach Aggregator;

(b) Each of BCE-Mach Aggregator, the current officers and employees who own indirect equity interests in Predecessor, BCE-Mach LLC and BCE-Mach II LLC and Mach Resources, LLC will contribute 100% of their respective membership interests in Predecessor, BCE-Mach LLC and BCE-Mach II LLC to the Company in exchange for a pro rata allocation of 100% of the limited partner interests in the Company;

(c) The Company will contribute 100% of its membership interests in Predecessor, BCE-Mach LLC and BCE-Mach II LLC to Mach Natural Resources Intermediate LLC ("Intermediate") in exchange for 100% of the membership interests in Intermediate; and

(d) Intermediate will contribute 100% of its membership interests in Predecessor, BCE-Mach LLC and BCE-Mach II LLC to Mach Natural Resources Holdco LLC ("Holdco") in exchange for 100% of the membership interests in Holdco.

2. Pro Forma Adjustments and Assumptions

The Company made the following adjustments and assumptions in preparation of the audited pro forma financial statements:

(a) Reflects estimated gross proceeds of $200 million from the issuance and sale of common units at an assumed initial public offering price of $ per unit, net of underwriting discounts and commissions of $ million, in the aggregate, and additional estimated expenses related to the Offering of approximately $ million and the use of the net proceeds therefrom as follows:

- Pay down $ million of outstanding borrowings under the Company's existing credit facilities, which was $174.0 million as of June 30, 2023.
- Enter into the New Credit Facility and capitalize any loan origination fees which will be amortized into interest expense over the term of the New Credit Facility. The Company assumed the balance on the New Credit Facility to be zero.

(b) Adjustment reflects removal of historical cost and accumulated depreciation of oil and gas properties of BCE-Mach and BCE-Mach II, and replacement with current fair value. The fair value of the oil and gas properties was assessed by utilizing a fair value reserve report that used future pricing and other commonly used valuation techniques.

(c) Adjustment reflects removal of certain operator owned equipment from other property, plant, and equipment, as it is inclusive in value of oil and gas properties in new fair value, as well as the fair value of BCE-Mach II's gathering assets. The fair value of the gathering assets was assessed using the income approach.

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2. Pro Forma Adjustments and Assumptions (cont.)

(d) Adjustment reflects removal of all loan origination fees on the Existing Credit Facilities, as these will cease to exist upon completion of the transaction. Loan origination fees stemming from the New Credit Facility will be capitalized and amortized into interest expense over the term of the New Credit Facility.

(e) Adjustment reflects removal of goodwill as there is no implied goodwill on the transaction.

(f) Adjustment reflects changes to depreciation, depletion and amortization expense that would have been incurred as if the transaction occurred on January 1, 2022 as a result of new fair value of oil and gas properties.

(g) Adjustment reflects changes to depreciation and amortization of other assets that would have been incurred as if the transaction occurred on January 1, 2022 based on new fair value of other property and equipment.

(h) Adjustment reflects removal of all equity compensation expense associated with B Units issued, as these units will cease to exist upon completion of the transaction.

(i) Adjustment reflects the reduction of interest expense of the Existing Credit Facilities from the use of offering proceeds to pay down debt outstanding. The Company assumed no borrowings under the New Credit Facility throughout 2022 and 2023, therefore the only interest expense will be the amortization of any loan origination fees associated with the New Credit Facility.

(j) Adjustment reflects the reduction of the loss on debt extinguishment as existing credit facility would have been paid down and replaced with the New Credit Facility.

3. Supplementary Disclosure for Oil and Gas Producing Activities

The following tables present the pro forma standardized measure of the discounted net future cash flows and changes applicable to Mach Natural Resources' proved reserves. The future cash flows are discounted at 10% per year and assume continuation of existing economic conditions.

The standardized measure of discounted future net cash flows, in management's opinion, should be examined with caution. The basis for this table is the reserve studies prepared by independent petroleum engineering consultants, which contain imprecise estimates of quantities and rates of production of reserves. Revisions of previous year estimates can have a significant impact on these results. Also, exploration costs in one year may lead to significant discoveries in later years and may significantly change previous estimates of proved reserves and their valuation. Therefore, the standardized measure of discounted future net cash flow is not necessarily indicative of the fair value of Mach Natural Resources' proved oil and natural gas properties.

The data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves since the computations are based on a large number of estimates and assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. Actual future prices and costs are likely to be substantially different from the prices and costs utilized in the computation of reported amounts.

Oil (MMbbl)	BCE-Mach_III (Predecessor)	BCE-Mach	BCE-Mach II	Pro Forma
December 31, 2021	35.8	16.4	1.6	53.8
Revisions of previous estimates	15.7	1.1	0.2	17.0
Purchases in place	1.9	—	—	1.9
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(4.8)	(1.0)	(0.1)	(5.9)
December 31, 2022	48.6	16.5	1.7	66.8
Proved Developed Reserves				
December 31, 2021	22.8	12.3	1.6	36.7
December 31, 2022	30.0	11.7	1.7	43.4
Proved Undeveloped Reserves				
December 31, 2021	13.0	4.1	—	17.1
December 31, 2022	18.6	4.8	—	23.4

MACH NATURAL RESOURCES LP
Notes to Pro Forma Condensed Consolidated Financial Statements

3. Supplementary Disclosure for Oil and Gas Producing Activities (cont.)

Natural Gas (bcf)	BCE-Mach III (Predecessor)	BCE-Mach	BCE-Mach II	Pro Forma
December 31, 2021	437.1	241.6	86.2	764.9
Revisions of previous estimates	167.6	28.3	14.7	210.6
Purchases in place	72.5	—	5.6	78.1
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(47.6)	(15.8)	(7.6)	(71.0)
December 31, 2022	629.6	254.1	98.9	982.6
Proved Developed Reserves				
December 31, 2021	415.1	210.9	86.2	712.2
December 31, 2022	527.4	212.0	98.9	838.3
Proved Undeveloped Reserves				
December 31, 2021	22.0	30.7	—	52.7
December 31, 2022	102.2	42.1	—	144.3

NGL (MMbbl)	BCE-Mach III (Predecessor)	BCE-Mach	BCE-Mach II	Pro Forma
December 31, 2021	30.1	15.3	5.5	50.9
Revisions of previous estimates	11.4	1.9	1.7	15.0
Purchases in place	8.1	—	—	8.1
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(2.8)	(1.0)	(0.5)	(4.3)
December 31, 2022	46.8	16.2	6.7	69.7
Proved Developed Reserves				
December 31, 2021	29.8	13.6	5.5	48.9
December 31, 2022	39.2	13.8	6.7	59.7
Proved Undeveloped Reserves				
December 31, 2021	0.3	1.7	—	2.0
December 31, 2022	7.6	2.4	—	10.0

Total (MMBoe)	BCE-Mach III (Predecessor)	BCE-Mach	BCE-Mach II	Pro Forma
December 31, 2021	138.7	71.9	21.5	232.1
Revisions of previous estimates	54.9	7.7	4.3	66.9
Purchases in place	22.2	—	1.0	23.2
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(15.5)	(4.6)	(1.9)	(22.0)
December 31, 2022	200.3	75.0	24.9	300.2
Proved Developed Reserves				
December 31, 2021	121.7	61.0	21.5	204.2
December 31, 2022	157.1	60.8	24.9	242.8
Proved Undeveloped Reserves				
December 31, 2021	17.0	10.9	—	27.9
December 31, 2022	43.2	14.2	—	57.4

MACH NATURAL RESOURCES LP
Notes to Pro Forma Condensed Consolidated Financial Statements

3. Supplementary Disclosure for Oil and Gas Producing Activities (cont.)

The pro forma standardized measure of discounted estimated future net cash flows was as follows as of December 31, 2022 (in thousands):

(in thousands)	BCE-Mach III (Predecessor)	BCE-Mach	BCE-Mach II	Pro Forma
Future cash inflows	$ 9,666,636	$ 3,206,749	$ 852,310	$ 13,725,695
Future costs:				—
Production[1]	(3,143,467)	(1,086,699)	(292,974)	(4,523,140)
Development[2]	(876,115)	(241,007)	(23,486)	(1,140,608)
Income taxes[3]	—	—	—	—
Future net cash flows	5,647,054	1,879,043	535,850	8,061,947
10% annual discount	(2,693,549)	(1,029,073)	(281,020)	(4,003,642)
Standardized measure	$ 2,953,505	$ 849,970	$ 254,830	$ 4,058,305

The change in the pro forma standardized measure of discounted estimated future net cash flows were as follows for 2022 (in thousands):

(in thousands)	BCE-Mach III (Predecessor)	BCE-Mach	BCE-Mach II	Pro Forma
Standardized measure, beginning of period	$ 1,413,611	$ 540,643	$ 124,185	$ 2,078,439
Revisions of previous quantity estimates	962,927	98,988	45,324	1,107,239
Changes in estimated future development costs	169,405	30,957	210	200,572
Purchases of minerals in place	201,135	—	9,699	210,834
Net changes in prices and production costs	442,599	301,637	100,586	844,822
Accretion of discount	141,361	54,064	12,418	207,843
Sales of oil and gas produced, net of production costs	(669,138)	(150,356)	(47,578)	(867,072)
Development costs incurred during the period	261,650	14,619	441	276,710
Change in timing of estimated future production and other	29,955	(40,582)	9,545	(1,082)
Standardized measure, end of period	$ 2,953,505	$ 849,970	$ 254,830	$ 4,058,305

1 Production costs include production severance taxes, ad valorem taxes and operating expenses.
2 Development costs include plugging expenses, net of salvage and net capital investment.
3 Income taxes — the Company is a limited partnership treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, with taxable income of the Company passed through to partners based on their respective share. Limited partnerships are subject to state income taxes in Texas. Due to immateriality, state income taxes related to the Texas margin tax are not included in our Standardized Measure calculation.

BCE-Mach III LLC Consolidated Financial Statements and Report of Independent Registered Public Accounting Firm

As of December 31, 2022 and 2021, and for the years ended December 31, 2022 and 2021

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Members
BCE-Mach III LLC

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of BCE-Mach III LLC (a Delaware limited liability company) and subsidiary (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of operations, members' equity, and cash flows for the years then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Change in accounting principle

As discussed in Note 12 to the financial statements, the Company has changed its method of accounting for leases in 2022 due to the adoption of FASB Accounting Standards Codification 842, *Leases*.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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 Company in accordance with 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 standardsof the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2020.

Oklahoma City, Oklahoma
June 27, 2023

BCE-MACH III LLC
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 29,417	$ 59,272
Accounts receivable – joint interest and other	21,490	18,270
Accounts receivable – oil, gas, and NGL sales	108,277	75,610
Inventories	24,700	4,943
Other current assets	2,349	20,379
Total current assets	186,233	178,474
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	749,934	337,049
Less: accumulated depreciation, depletion and amortization	(139,514)	(59,057)
Oil and natural gas properties, net	610,420	277,992
Other property, plant and equipment	82,125	70,014
Less: accumulated depreciation	(9,198)	(4,823)
Other property, plant and equipment, net	72,927	65,191
Other assets	3,052	3,722
Operating lease assets	14,809	—
Total assets	$ 887,441	$ 525,379
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 19,429	$ 7,582
Accrued liabilities	60,169	29,429
Revenue payable	52,196	51,139
Short-term derivative liabilities	10,080	28,315
Current portion of operating lease	10,767	—
Other short-term liabilities	—	12,974
Total current liabilities	152,641	129,439
Long-term debt	84,900	85,800
Asset retirement obligations	52,359	25,620
Long-term derivative liabilities	—	5,100
Long-term portion of operating lease	4,042	—
Other long-term liabilities	269	721
Total long-term liabilities	141,570	117,241
Commitments and contingencies (Note 11)		
Members' equity	593,230	278,699
Total liabilities and members' equity	$ 887,441	$ 525,379

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31,	
	2022	**2021**
Revenue		
Oil, natural gas, and NGL sales	$ 860,388	$ 397,500
Midstream revenue	44,373	31,883
Loss on oil and natural gas derivatives	(67,453)	(67,549)
Product sales	100,106	30,663
Total revenues	937,414	392,497
Operating expenses		
Gathering and processing	47,484	27,987
Lease operating expense	95,941	45,391
Midstream operating expense	15,157	12,248
Cost of product sales	94,580	28,687
Production taxes	47,825	21,165
Depreciation, depletion, amortization and accretion – oil and natural gas	84,070	37,537
Depreciation and amortization – other	4,519	3,148
General and administrative	25,454	60,927
Total operating expenses	415,030	237,090
Income from operations	522,384	155,407
Other (expense) income		
Interest expense	(4,852)	(1,656)
Other (expense) income, net	(691)	1,023
Loss on contingent consideration	—	(16,400)
Total other expense	(5,543)	(17,033)
Net income	$ 516,841	$ 138,374

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
CONSOLIDATED STATEMENT OF MEMBERS' EQUITY
(in thousands)

	Total Members' Equity
Balance at December 31, 2020	$ 139,561
Contributions	101,461
Distributions	(146,000)
Equity Compensation	45,303
Net income	138,374
Balance at December 31, 2021	$ 278,699
Contributions	65,000
Distributions	(274,837)
Equity Compensation	7,527
Net income	516,841
Balance at December 31, 2022	$ 593,230

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31,	
	2022	**2021**
Cash flows from operating activities		
Net income	$ 516,841	$ 138,374
Adjustments to reconcile net income to cash provided by operating activities		
Depreciation, depletion and amortization	88,589	40,685
Loss on derivative instruments	67,453	67,549
Cash payments on settlement of derivative contracts, net	(94,201)	(59,381)
Debt issuance costs amortization	375	312
Loss on contingent consideration	—	16,400
Settlement of contingent consideration	(13,547)	(9,553)
Equity based compensation	7,527	45,303
Gain on sale of assets	(45)	(85)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable, inventories, other assets	(30,671)	(74,462)
Revenue payable	(908)	24,389
Accounts payable and accrued liabilities	12,178	8,966
Settlement of asset retirement obligations	(49)	(35)
Net cash provided by operating activities	553,542	198,462
Cash flows from investing activities		
Capital expenditures for oil and natural gas properties	(233,584)	(37,789)
Capital expenditures for other property and equipment	(9,441)	(3,219)
Acquisition of assets	(96,620)	(154,419)
Acquisition of assets – related party	(37,242)	—
Proceeds from sales of oil and natural gas properties	3,996	599
Proceeds from sales of other property and equipment	231	85
Net cash used in investing activities	(372,660)	(194,743)
Cash flows from financing activities		
Proceeds from borrowings on credit facility	—	72,900
Repayments of borrowings on credit facility	(900)	(30,800)
Debt issuance costs	—	(245)
Contributions from members	65,000	101,461
Distributions to members	(274,837)	(146,000)
Settlement of contingent consideration	—	(1,900)
Net cash used in financing activities	(210,737)	(4,584)
Net decrease in cash and cash equivalents	(29,855)	(865)
Cash and cash equivalents, beginning of period	59,272	60,137
Cash and cash equivalents, end of period	$ 29,417	$ 59,272

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

BCE-Mach III LLC ("the Company") was formed on December 28, 2019 as a limited liability company under the laws of the State of Delaware. On December 28, 2019, the Company entered into a limited liability company agreement (the "LLC agreement") with its initial member. The LLC agreement was amended and restated on March 25, 2021 to allow additional equity to be issued to certain employees of the Company. The Company wholly owns one subsidiary, BCE-Mach III Midstream Holdings LLC. On April 9, 2020, the Company closed on an acquisition and operations subsequently began for the Company. The Company owns and operates producing wells and undeveloped acreage primarily in Oklahoma and Texas. The Company also owns gas gathering lines, gas processing facilities, and saltwater disposal facilities.

2. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements included herein were prepared fromrecords of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP") and include accounts of our wholly owned subsidiary. Intercompany accounts and transactions have been eliminated upon consolidation. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP 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. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the fair value determination of acquired assets and liabilities, equity based compensation, the fair value of contingent consideration, and the fair value estimates of commodity derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. The Company extends credit to joint interest owners and generally does not require collateral. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary as of December 31, 2022 or 2021.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments in the statement of operations.

Oil and Natural Gas Operations

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities, which are expensed as incurred. Capitalized costs are depreciated using the unit-of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $5.18 and $3.46 for the years ended December 31, 2022 and 2021, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $80.5 million and $35.8 million for the years ended December 31, 2022 and 2021, respectively.

Under the full cost method, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each year. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the Internal Revenue Service ("IRS") recognition of the Company as a flow-through entity. No impairments on proved oil and natural gas properties were recorded for the year ended December 31, 2022 or 2021.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. As of December 31, 2022, the Company had no properties excluded from the full cost pool. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas, and natural gas liquids ("NGL") reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Other Property and Equipment, Net

Other property and equipment primarily consists of a gathering system, processing plant, and salt water disposal system. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from two to 39 years. Depreciation expense for other property and equipment was $4.5 million and $3.1 million for the years ended December 31, 2022 and 2021, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment was recorded for the years ending December 31, 2022 or 2021.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production and midstream equipment not placed in service as of December 31, 2022 and 2021. The Company's production equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units, as well as pipe for midstream operations.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $1.0 million, net of accumulated amortization of $0.8 million as of December 31, 2022. As of December 31, 2021, other assets include capitalized costs related to the credit facility of $1.0 million, net of accumulated amortization of $0.5 million. These costs are being amortized over the term of the credit facility and are reported as interest expense on the Company's statement of operations.

Income Taxes

The Company is an LLC taxed as a partnership, and any associated tax liability is the responsibility of the individual members of the LLC. Accordingly, no provision for income taxes has been made in these financial statements.

The Company disallows the recognition of tax positions not deemed to meet a "more-likely-than not" threshold of being sustained by the applicable tax authority. The Company's policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company has not recognized any potential interest or penalties in its financial statements for the year ended December 31, 2022. The Company's tax years 2021 and 2020 remain open for examination by state authorities.

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction or salt water disposal began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO as of December 31, 2022 and 2021 (in thousands):

	December 31, 2022	December 31, 2021
Asset retirement obligation at beginning of period	$ 25,620	$ 10,411
Liabilities assumed in acquisitions	21,385	13,281
Liabilities incurred	1,660	240
Liabilities settled	(136)	(19)
Liabilities revised	218	(21)
Accretion expense	3,612	1,728
Asset retirement obligation at end of period	$ 52,359	$ 25,620

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 8. Derivative Contracts, for the Company's management of price volatility.

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statement of operations.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGL are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statement of operations.

Midstream Revenue and Product Sales

The Company's gathering and processing revenue is generated from owned gathering and compression systems and processing plants acquired in the Company's acquisitions. The Company charges a gathering, compression, processing rate per MMBtu transported through the gathering system and processing plant. The Company also gathers and disposes of salt water from producing wells through an owned pipeline system and disposal wells. The Company charges a fixed rate per barrel of water for disposal.

Product sales are generated from the Company's sale of natural gas, oil and NGL production purchased from third parties and subsequently gathered and processed through the Company's owned midstream facilities. Product sales includes activity from certain third-party percent-of-proceeds contracts where the Company keeps a contractually based percentage of proceeds from the sale of natural gas and NGL production, as payment for processing natural gas from the third parties. The costs of buying natural gas, oil and NGL production from third party shippers are included as costs of product sales on the statement of operations.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company 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. Each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the period ended December 31, 2022, three purchasers each accounted for more than 10% of the Company's revenue: Hinkle Oil and Gas Inc. (31.5%); NextEra Energy Marketing, LLC (17.0%); and Phillips 66 Company (16.9%). For the year ended December 31, 2021, four purchasers each accounted for more than 10% of the Company's revenue: Phillips 66 Company (33.5%); NextEra

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Energy Marketing, LLC (20.2%); Hinkle Oil and Gas Inc. (13.3%), and ONEOK Hydrocarbon L.P. (13.9%). The Company's receivables as of December 31, 2022 and 2021 from oil and gas sales are concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

As of December 31, 2022, the Company had one customer that represented approximately 20.8% of our total joint interest receivables. As of December 31, 2021, the Company had one customer that represented approximately 12.3% of joint interest receivables.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Year Ended December 31,	
	2022	2021
Revenues:		
Oil	$ 447,997	$ 189,390
Natural gas	300,785	131,784
NGL	109,756	75,081
Gross oil, natural gas, and NGL sales	858,538	396,255
Transportation, gathering and marketing	1,850	1,245
Net oil, natural gas, and NGL sales	$ 860,388	$ 397,500

Recent Accounting Pronouncements Adopted

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)". ASU 2016-02 establishes a right of use "ROU" model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. All leases create an asset and a liability for the lessee and therefore recognition of those lease assets and lease liabilities is required by ASU 2016-02. When measuring lease assets and liabilities, payments to be made in optional extension periods should be included if the lessee is reasonably certain to exercise the option. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 will not impact the accounting or financial presentation of our mineral leases.

In July 2018, the FASB issued Accounting Standards Update 2018-11, "Leases (Topic 842): Targeted Improvements", which included the option to implement the standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings, as opposed to the modified retrospective transition method required when ASU 2016-02 was issued. This guidance is effective for periods after December 15, 2021 and the Company implemented effective January 1, 2022. See Note 12. Leases, for further discussion.

Recent Accounting Pronouncements Issued But Not Yet Adopted

Accounting Standards Update 2016-13, "Financial Instrument-Credit Losses: Measurement of Credit Losses on Financial Instruments," which amends reporting guidance on credit loses for certain financial instruments. The Company's primary risk for credit losses related to its receivables from joint interest owners in our operated oil and natural gas wells. This guidance is effective for periods after December 15, 2022. The Company is currently implementing it with no significant changes expected to the financial statements as the Company has no history of credit losses.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. Supplemental Cash Flow Information

Supplemental disclosures to the statement of cash flows are presented below (in thousands):

	Year ended December 31,	
	2022	2021
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 4,339	$ 1,150
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ 29,363	$ 12,392
Asset retirement cost capitalized	$ 1,660	$ 240
Right-of-use assets obtained in exchange for lease liabilities	$ 22,266	$ —

4. Acquisitions

2022 Acquisitions

Camino Natural Resources, LLC

On May 17, 2022, the Company executed a purchase and sale agreement with Camino Natural Resources, LLC for the sale of certain oil and gas properties in Oklahoma for $22.0 million subject to certain adjustments. The transaction closed on June 30, 2022 and was effective as of January 1, 2022. The acquisition was funded through contributions from members and operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and gas properties of $15.8 million, net of asset retirement obligations assumed of $2.2 million and revenue suspense liabilities of $0.4 million. Cash paid for assets as of December 31, 2022 was $15.4 million.

Scout Energy, LP

On May 6, 2022, the Company executed a purchase and sale agreement with Scout Energy Group I, LP and other affiliates for the sale of certain oil and gas properties in Oklahoma and Texas for $66.0 million subject to certain adjustments. The transaction closed on June 30, 2022 and was effective as of March 1, 2022. The acquisition was funded through contributions from members and operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. The fair value of the midstream assets was assessed using a variety of valuation techniques including the income and cost approach. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

Assets acquired and liabilities assumed	
Oil and natural gas properties	$ 69,103
Other property and equipment	3,000
Other assets	147
Revenue suspense	(1,415)
Asset retirement obligations assumed	(11,841)
Total assets acquired, net of liabilities assumed	$ 58,994

Cash paid for assets as of December 31, 2022 was $59.0 million.

Woolsey Energy Corporation

On December 1, 2021, the Company executed a purchase and sale agreement with Woolsey Energy Corporation and other affiliates for the sale of certain oil and gas properties in Kansas, Oklahoma, and Texas for $26.0 million subject to certain adjustments. The transaction closed on January 31, 2022 and was effective as of December 1, 2021. The acquisition was funded through operational cash flow. The purchase was accounted for as

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Acquisitions (cont.)

an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and gas properties of $23.2 million, net of asset retirement obligations assumed of $6.4 million, and inventory of $1.5 million. Cash paid for assets as of December 31, 2022 was $24.7 million, including a $2.6 million deposit included in other current assets as of December 31, 2021.

BCE-Stack Development LLC

On November 12, 2021, the Company executed a purchase and sale agreement with BCE-Stack Development LLC for the sale of certain oil and gas properties in Oklahoma for $40.5 million subject to certain adjustments. The transaction closed on February 28, 2022 and was effective as of January 1, 2022. The acquisition was funded through operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and gas properties of $37.2 million, net of asset retirement obligations assumed of $0.5 million. Cash paid for assets as of December 31, 2022 was $37.2 million, including a $15.0 million deposit included in other current assets as of December 31, 2021.

2021 Acquisitions

Chisholm Oil and Gas Operating, LLC

On December 30, 2021, the Company executed a purchase and sale agreement with Chisholm Oil and Gas Operating, LLC for the sale of certain oil and gas properties in Oklahoma for $33.0 million subject to certain adjustments. The transaction closed on December 31, 2021 and was effective as of October 1, 2021. The acquisition was funded through operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and gas properties of $28.9 million, net of asset retirement obligations assumed of $1.1 million.

MEP Mid-Con III, LLC

On June 15, 2021, the Company executed a purchase and sale agreement with MEP Mid-Con III, LLC for the sale of certain oil and gas properties in Oklahoma for $34.0 million subject to certain adjustments. The transaction closed on July 29, 2021 and was effective as of March 1, 2021. The acquisition was primarily funded from equity contributions from its members. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and gas properties of $25.7 million, net of asset retirement obligations assumed of $0.1 million.

Cimarex Energy Co.

On April 26, 2021 the Company executed a purchase and sale agreement with Cimarex Energy Co. (“XEC”) for the sale of certain oil and gas assets in Oklahoma and Texas, two gas processing plants, and a gathering system at a purchase price of $95.7 million, subject to certain adjustments. The transaction with XEC closed on June 18, 2021 and was effective as of March 1, 2021. The sale was primarily funded through contributions from its members. The purchase was accounted for as a business combination, under the acquisition method as the Company obtained control of a business by obtaining the legal right to use and develop the oil and natural gas properties included in the purchase and sale agreement, as well as additional oil and gas related assets that can be used to enhance the value of the business. The fair value of the oil and gas properties acquired was assessed by utilizing a fair value reserve report that used future pricing and other commonly used valuation techniques.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Acquisitions (cont.)

The fair value of the midstream assets was assessed using a variety of valuation techniques including the income and cost approach. Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

Assets acquired and liabilities assumed		
Oil and natural gas properties	$	85,959
Other property and equipment		13,474
Inventory		122
Linefill		465
Gas imbalances		(149)
Revenue suspense		(931)
Asset retirement obligations assumed		(12,440)
Total assets acquired, net of liabilities assumed	$	86,500

5. Property and Equipment

The Company's property and equipment consists of the following (in thousands):

	December 31, 2022	December 31, 2021
Oil and natural gas properties		
Proved properties	$ 749,934	$ 337,049
Accumulated depreciation and depletion	(139,514)	(59,057)
Oil and natural gas properties, net	610,420	277,992
Other property and equipment		
Gas gathering system	24,713	17,089
Gas processing plants	33,858	29,943
Water disposal assets	21,029	18,453
Other assets	2,525	4,529
Total other property and equipment	82,125	70,014
Accumulated depreciation, depletion and amortization	(9,198)	(4,823)
Total other property and equipment, net	$ 72,927	$ 65,191

6. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	December 31, 2022	December 31, 2021
Operating expenses	$ 10,198	$ 4,762
Capital expenditures	37,375	12,900
Payroll costs	2,450	1,603
Hedge Settlements	898	4,311
Severance and other tax	3,662	3,031
Midstream shipper payable	5,157	2,318
General, administrative, and other	429	504
Total accrued liabilities	$ 60,169	$ 29,429

7. Long-Term Debt

On May 19, 2020, the Company entered into a credit agreement for a revolving credit facility ("the credit facility") with a syndicate of banks, including MidFirst Bank ("MidFirst"), who serves as administrative agent and issuing bank. The credit facility provides for a maximum of $300.0 million, subject to commitments of $100.0 million as of December 31, 2022 and matures in May 2024. Outstanding obligations under the credit facility are secured by substantially all of the Company's assets. The amount available to be borrowed under the credit facility is subject to a borrowing base that is redetermined semiannually each May and November in an amount determined by the lenders. As of December 31, 2022, and 2021, there was $84.9 million and $85.8 million, respectively, outstanding under the credit facility.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. Financial ratios the Company is required to maintain on a quarterly basis include the ratio of total debt to EBITDAX not greater than 3.25 and the ratio of current assets to current liabilities of no less than 1.0. As of December 31, 2022 and 2021, the Company was in compliance with all applicable covenants under the credit facility.

The credit facility requires mandatory payments when the consolidated cash balance of the Company as defined in the credit agreement exceeds $20.0 million. The consolidated cash balance is defined as the unrestricted cash held by the Company shown and on the balance sheet less cash set aside to pay royalty obligations, working interest obligations, production payments, vendor payments, suspense payments, severance and ad valorem taxes, payroll, payroll taxes, other taxes, and employee wage and benefits. The Company calculates the amount to be paid down to maintain compliance with the cash balance covenant at the end of each month. As of December 31, 2022 and 2021 there was no excess cash balance.

At the Company's election, outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Company that is equal to an alternative base rate (which is equal to the greatest of the most recent prime rate, the Federal Funds effective rate plus 0.5%, and 1-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 2.0% to 3.0% in the case of the alternate base rate and from 3.25% to 4.25% in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding. The Company is obligated to pay a quarterly commitment fee of 0.50% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of December 31, 2022 was 7.7%.

8. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These transactions are in the form of fixed price swaps. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 9, Fair Value Measurements for additional information regarding fair value measurements.

8. Derivative Contracts (cont.)

The following table summarizes the open financial derivative positions as of December 31, 2022, related to oil production:

Period	Volume (Mbbl)	Weighted Average Fixed Price
January – September 2023	605	$ 61.00

The following table summarizes the open financial derivative positions as of December 31, 2022, related to natural gas production:

Period	Volume (Mmbtu)	Weighted Average Fixed Price
January – October 2023	5,316	$ 4.42

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The following tables presents the gross amounts of recognized derivative liabilities, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	December 31, 2022	December 31, 2021
Derivative contracts – current, gross	$ 10,080	$ 28,315
Netting arrangements	—	—
Derivative contracts – current, net	$ 10,080	$ 28,315
Derivative contracts – long-term, gross	$ —	$ 5,100
Netting arrangements	—	—
Derivative contracts – long-term, net	$ —	$ 5,100

Gains and Losses. The following table presents the settlement and mark-to-market ("MTM") gains and losses presented as a gain or loss on derivatives in the statement of operations for the years ended December 31, 2022 and 2021 (in thousands):

	Year ended December 31,	
	2022	2021
Settlements on derivatives	$ (90,788)	$ (61,265)
MTM gains (losses) on derivatives, net	23,335	(6,284)
Total losses on derivative contracts	$ (67,453)	$ (67,549)

The following table presents the losses recognized on oil and natural gas derivatives in the accompanying statement of operations for the years ended December 31, 2022 and 2021 (in thousands):

	Year ended December 31,	
	2022	2021
Oil derivatives	$ (32,581)	$ (54,585)
Natural gas derivatives	(34,872)	(12,964)
Total losses on derivative contracts, net	$ (67,453)	$ (67,549)

9. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 — Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.

Level 3 — Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

Contingent Overriding Royalty Interest. On January 15, 2020, the Company executed a purchase and sale agreement with Alta Mesa Holdings, LP ("AMH") for the sale of certain oil and gas assets in Oklahoma and Kingfisher Midstream LLC ("KFM") for the sale of midstream gathering and processing assets that primarily service the AMH oil and gas assets (the "AMH Acquisition"). On April 2, 2020, the Company entered into the first amendment to the purchase and sale agreement with AMH and KFM. As part of the first amendments to the purchase and sale agreement, consideration of a 5% contingent overriding royalty interest ("the ORRI") was reserved when certain conditions regarding the market price of oil are met. There is a maximum consideration payable of $25 million related to the ORRI, and the ORRI will be terminated at the earlier of $25 million paid out or three years from the date of the acquisition. The conditions for the ORRI to take effect are that the West Texas Intermediate futures price ("WTI") of oil trades at or above $45/Bbl for 15 consecutive trading days. The ORRI may also go out of effect after previously being in effect if WTI trades below $45/Bbl for 15 consecutive trading days. Payments relating to this liability for the years ended December 31, 2022, and 2021, were $13.6 million and $11.4 million, respectively.

During 2022, the Company reached the maximum consideration of $25 million. As such, there was no liability recorded as of December 31, 2022. The Company determined the fair value of the ORRI using a Monte Carlo model, where the primary input is WTI futures pricing. The fair value of the ORRI as of December 31, 2021 was $13.7 million, with $13.0 million in other short-term liabilities and $0.7 million in other long-term liabilities. For the year ended December 31, 2021, the Company recognized losses of $16.4 million in relation to the ORRI. No loss was recognized for the year ended December 31, 2022.

9. Fair Value Measurements (cont.)

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2022 and 2021 (in thousands):

	Level 1	Level 2	Level 3	Fair Value
As of December 31, 2021				
Liabilities:				
Derivative Instruments	$ —	$ 33,415	$ —	$ 33,415
Contingent overriding royalty interest	$ —	$ 13,695	$ —	$ 13,695
As of December 31, 2022				
Liabilities:				
Derivative Instruments	$ —	$ 10,080	$ —	$ 10,080

Fair Value on a Non-Recurring Basis

The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair values due to the short-term maturities of these instruments.

The carrying amount of the Company's credit facility approximates fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

10. Equity Compensation and Deferred Compensation Plan

As part of the Company's amended and restated LLC agreement as of March 25, 2021, incentive units (Class B Units) were issued to certain employees as compensation for services to be rendered to the Company. In determining the appropriate accounting treatment, the Company considered the characteristics of the awards in terms of treatment as stock-based compensation. US GAAP generally requires that all equity awards granted to employees be accounted for at fair value and recognized as compensation cost over the vesting period.

The incentive units are subject to graded vesting over a period of 3 or 4 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units forfeits unvested incentive units upon ceasing to be an employee of the Company, excluding limited exceptions. The Company recognizes forfeitures as they occur. Holders of incentive units participate in distributions upon the Company meeting a certain requisite financial internal rate of return threshold as defined in the amended LLC agreement.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those

10. Equity Compensation and Deferred Compensation Plan (cont.)

valuation methodologies. For awards granted for the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 53%
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 1.40%

On March 25, 2021, all 20,000 authorized incentive units were granted. Total non-cash compensation cost related to the incentive units was $7.5 and $37.4 million for the years ended December 31, 2022 and 2021, respectively. As of December 31, 2022, there was $2.6 million in unrecognized compensation cost related to incentive units, which is expected to be recognized over a weighted-average period of 0.5 years.

A summary of the incentive unit awards as of December 31, 2022 is as follows:

	Class B units	Weighted Average Grant Date Fair Value
Grated at March 25, 2021	20,000	$ 2,378.80
Vested	(9,667)	$ 2,378.80
Unvested at December 31, 2021	10,333	$ 2,378.80
Vested	(3,665)	$ 2,378.80
Unvested at December 31, 2022	6,668	$ 2,378.80

As part of the Company's amended and restated LLC agreement as of March 25, 2021 and the Class A-2 Issuance Agreement, the Company issued 1,349 Class A-2 Units to an employee of Mach Resources LLC ("Mach Resources") for services performed for the company. Additionally, A-2 Units were issued on a quarterly basis to the employee for the year ended December 31, 2021 and vested on the grant date. In accordance with US GAAP, the equity awards granted to the employee will be accounted for at fair value and recognized as compensation cost over the vesting period.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For awards granted for the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 53%
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 1.40%

There were no unvested Class A-2 Units and no related unrecognized costs as of December 31, 2022. Non-cash compensation cost related to the Class A-2 Units was $7.8 million for the year ended December 31, 2021.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Commitments and Contingencies

Legal Matters. In the ordinary course of business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. The Company did not recognize any material liability as of December 31, 2022 or 2021. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

12. Leases

Effective January 1, 2022, the Company adopted ASU No. 2016-02, Leases (Topic 842). The new standard supersedes the previous lease guidance by requiring lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases. The Company adopted the new standard on a prospective basis using the simplified transition method permitted by ASU No. 2018-11, Leases (Topic 842): Targeted Improvements. No cumulative-effect adjustment to retained earnings was required upon adoption of the new standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. The Company elected the package of practical expedients permitted under the new standard, which among other things, allows for lease and non-lease components in a contract to be accounted for as a single lease component for all asset classes and the carry forward of historical lease classifications.

Nature of Leases

The Company has operating leases on various vehicles and compressors with remaining lease durations in excess of one year. These leases have various expiration dates throughout 2026. The vehicles are used for field operations and leased from third parties. The Company recognizes right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses the U.S. 5 Year Treasury Rate in determining the present value of lease payments. Minor changes to the discount rate do not have a material impact to the calculation of the liability, therefore the Company will use this for all asset classes.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. Leases (cont.)

Future amounts due under operating lease liabilities as of December 31, 2022, were as follows (in thousands):

2023	$ 10,789
2024	3,434
2025	483
2026	251
Total lease payments	$ 14,957
Less: imputed interest	(148)
Total	$ 14,809

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the year ended December 31, 2022 (in thousands):

Operating lease cost	$ 7,462
Short-term lease cost	9,300
Total lease cost	$ 16,762

The weighted-average remaining lease term as of December 31, 2022 was 1.56 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2022 was 3.99%.

13. Members' Equity

The Company was formed with one member, BCE-Mach Holdings III LLC. Upon formation, the Company consisted of one class of common interests, that were all owned by the member. An amended and restated LLC agreement was executed on February 18, 2020, replacing BCE-Mach Holdings III LLC with BCE-Mach Intermediate Holdings III LLC as the sole initial member. Contributions from the member were $150.0 million for the year ended December 31, 2020. On March 25, 2021, per the amended and restated LLC agreement and the Class A-2 Issuance Agreement, the Company issued 150,000 Class A-1 Units to the initial member, and 1,349 Class A-2 Units to an employee of Mach Resources for service performed for the Company. Additionally, Class A-2 Units were granted to the employee on a quarterly basis throughout 2021. As of December 31, 2022, there were 3,504 total Class A-2 Units issued to the employee, which have substantially all the same rights as the initial member. In 2022, the Class A-2 Issuance Agreement was updated and there are no additional units being granted to the employee. As part of a long-term incentive plan for certain employees, 20,000 Class B Units were outstanding as of December 31, 2022. The Class B Units represent a non-voting interest in the Company that allows the holder to participate in distributions once the Company's Class A shares have met a certain requisite financial internal rate of return in accordance with the LLC agreement.

Contributions from the members were $65.0 million and $101.5 million for the years ended December 31, 2022 and 2021, respectively. Distributions to the members were $274.8 million and $146.0 million for the years ended December 31, 2022 and 2021, respectively.

14. Related Parties

Management Services Agreement. Upon formation of the Company, the Company entered into a management services agreement ("MSA") with Mach Resources. Under the MSA, Mach Resources manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company distributes funding to Mach Resources for performance under the MSA. During the year ended December 31, 2022 and 2021, the Company paid Mach Resources $33.7 million, which was inclusive of $2.0 million in management fees, and $23.6 million, which included no management fees, respectively. As of December 31, 2022 the Company owed $0.4 million to MR. As of December 31, 2021, the Company had $0.2 million in prepaid assets with Mach Resources.

14. Related Parties (cont.)

BCE-Stack Development LLC. BCE-Stack Development LLC ("BCE-Stack") is an affiliate of the member, and previously was an owner of working and revenue interests in a subset of the Company's wells. BCE-Stack sold their interests in the wells to the Company on February 28, 2022. See Note 4. Acquisitions, for additional information on the acquisition. As of December 31, 2022 the Company had no receivables or payables with BCE-Stack. As of December 31, 2021 the Company had $0.4 million in joint interest receivables from BCE-Stack.

BCE-Mach LLC and BCE-Mach II LLC. BCE-Mach LLC and BCE-Mach II LLC are two related parties that also entered into a MSA with Mach Resources. These entities have shared ownership with the Company and operate primarily in different geographical locations than the Company. As of December 31, 2022 the Company has receivables from these related parties for approximately $0.7 million included in accounts receivable — joint interest and other. As of December 31, 2021 the Company had payables to these related parties for approximately $1.5 million included in accounts payable.

15. Subsequent Events

The Company has evaluated its financial statements for subsequent events through June27, 2023, the date the financial statements were available to be issued to ensure that any subsequent events that met the criteria for recognition and disclosure in this report have been properly included.

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

The following tables provide historical cost information regarding the Company's oil and gas operations located entirely in the United States:

Capitalized Costs related to Oil and Gas Producing Activities

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Proved properties	$ 749,934	$ 337,049
Accumulated depreciation, depletion, amortization and impairment	(139,514)	(59,057)
Net capitalized costs	$ 610,420	$ 277,992

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Acquisition	$ 130,866	$ 130,959
Development	262,889	51,886
Exploratory	—	—
Costs incurred	$ 393,755	$ 182,845

Results of Operations for Producing Activities

The following table includes revenue and expenses related to the production and sale of oil, natural gas, and NGLs. It does not include any derivative activity, interest costs or general and administrative costs.

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Revenues	$ 860,388	$ 397,500
Production costs	(191,250)	(94,543)
Depreciation, depletion, amortization and accretion	(84,070)	(37,537)
Results of operations from producing activities	$ 585,068	$ 265,420

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved undeveloped reserves or PUDs. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the US GAAP. 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.

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 2).

The standardized measure does not represent management's estimate of our future cash flows or the fair 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 affected 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 Summary

All of the Company's reserves are located in the United States. The following table sets forth the changes in the Company's net proved reserves (including developed and undeveloped reserves) for the years ended December 31, 2022 and 2021. Reserves estimates as of December 31, 2022 were estimated by the independent petroleum consulting firm Cawley, Gillespie & Associates, Inc.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Proved Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	14.8	139.7	9.2	47.3
Revisions of previous estimates	18.7	122.4	9.5	48.6
Purchases in place	5.1	207.3	13.6	53.1
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(2.8)	(32.3)	(2.2)	(10.3)
December 31, 2021	35.8	437.1	30.1	138.7
Revisions of previous estimates	15.7	167.6	11.4	54.9
Purchases in place	1.9	72.5	8.1	22.2
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(4.8)	(47.6)	(2.8)	(15.5)
December 31, 2022	48.6	629.6	46.8	200.3

Proved Developed Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	12.3	126.5	8.6	41.9
December 31, 2021	22.8	415.1	29.8	121.7
December 31, 2022	30.0	527.4	39.2	157.1

Proved Undeveloped Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	2.5	13.2	0.6	5.4
December 31, 2021	13.0	22.0	0.3	17.0
December 31, 2022	18.6	102.2	7.6	43.2

In 2021, the 53.1 mmboe acquisitions represents the reserves acquired from several acquisitions that closed in 2021, refer to note 4 for more information. The 48.6 mmboe of upward revisions in proved reserves were the result of a combination of higher commodity prices (20.9 mmboe), positive changes to production forecasts (4.6 mmboe), adjustments to product pricing differentials and lease operating expenses (5.9 mmboe) and the addition of PUDs based on drilling results (17.0 mmboe).

In 2022, the 22.2 mmboe of acquisitions represents the reserves acquired from several acquisitions that closed in 2022, refer to note 4 for more information. The 54.9 mmboe of upward revisions in proved reserves were the result of higher commodity prices (9.0 mmboe), the addition of PUDs (35.8 mmboe) and the addition of proved developed producing reserves associated with the drilling of wells within proved areas that were not booked as PUD at prior year-end (7.2 mmboe). The remainder was associated with revisions to reflect current lease operating expenses and production pricing differentials.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

The following table sets forth the standardized measure of discounted future net cash flow from projected production of the Company's oil and natural gas reserves:

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves (in thousands)	**December 31, 2022**	**December 31, 2021**
Future cash inflows	$ 9,666,636	$ 4,482,198
Future costs:		
Production[1]	(3,143,467)	(1,670,421)
Development[2]	(876,115)	(290,564)
Income taxes	—	—
Future net cash flows	5,647,054	2,521,213
10% annual discount	(2,693,549)	(1,107,602)
Standardized measure	$ 2,953,505	$ 1,413,611

(1) Production costs include production severance taxes, ad valorem taxes and operating expenses.
(2) Development costs include plugging expenses, net of salvage and net capital investment.

Changes in Standardized Measure of Discounted Future Net Cash Flows (in thousands)	**For the Year Ended December 31, 2022**	**2021**
Standardized measure, beginning of period	$ 1,413,611	$ 319,372
Revisions of previous quantity estimates	962,927	574,343
Changes in estimated future development costs	169,405	89,648
Purchases of minerals in place	201,135	319,488
Net changes in prices and production costs	442,599	379,219
Accretion of discount	141,361	31,937
Sales of oil and gas produced, net of production costs	(669,138)	(302,957)
Development costs incurred during the period	261,650	51,281
Change in timing of estimated future production and other	29,955	(48,720)
Standardized measure, end of period	$ 2,953,505	$ 1,413,611

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

Average oil prices used in the estimation of proved reserves and calculation of the standardized measure were $93.67 for 2022 and $66.56 for 2021. Average realized gas prices were $6.36 for 2022 and $3.60 for 2021. We used 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period.

BCE-Mach III LLC Unaudited Consolidated Financial Statements

As of June 30, 2023 and December 31, 2022 and for the six months ended June 30, 2023 and 2022

BCE-MACH III LLC
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands)

	June 30, 2023	December 31, 2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 48,846	$ 29,417
Accounts receivable – joint interest and other	20,093	21,490
Accounts receivable – oil, gas, and NGL sales	52,394	108,277
Inventories	20,958	24,700
Other current assets	2,088	2,349
Total current assets	144,379	186,233
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	939,516	749,934
Less: accumulated depreciation, depletion and amortization	(195,445)	(139,514)
Oil and natural gas properties, net	744,071	610,420
Other property, plant and equipment	87,015	82,125
Less: accumulated depreciation	(11,964)	(9,198)
Other property, plant and equipment, net	75,051	72,927
Other assets	2,124	3,052
Operating lease assets	13,687	14,809
Total assets	$ 979,312	$ 887,441
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 38,129	$ 19,429
Accrued liabilities	38,172	60,169
Revenue payable	50,569	52,196
Current portion of operating lease liabilities	10,692	10,767
Short-term derivative contracts	1,869	10,800
Total current liabilities	139,431	152,641
Long-term debt	91,900	84,900
Asset retirement obligations	54,592	52,359
Long-term portion of operating lease liabilities	3,176	4,042
Other long-term liabilities	686	269
Total long-term liabilities	150,354	141,570
Commitments and contingencies (Note 10)		
Members' equity	689,527	593,230
Total liabilities and members' equity	$ 979,312	$ 887,441

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(in thousands)

	Six months ended June 30,	
	2023	**2022**
Revenue		
Oil, natural gas, and NGL sales	$ 312,613	$ 408,442
Midstream revenue	13,318	19,883
Gain (loss) on oil and natural gas derivatives	15,742	(72,857)
Product sales	17,421	47,960
Total revenues	359,094	403,428
Operating expenses		
Gathering and processing	17,510	20,812
Lease operating expense	60,615	39,592
Midstream operating expense	5,538	6,976
Cost of product sales	15,575	44,958
Production taxes	15,526	22,675
Depreciation, depletion, and accretion – oil and natural gas	58,095	29,374
Depreciation and amortization – other	2,793	2,008
General and administrative	9,905	13,648
Total operating expenses	185,557	180,043
Income from operations	173,537	223,385
Other (expense) income		
Interest expense	(3,789)	(1,876)
Other (expense) income, net	(245)	1,121
Total other expense	(4,034)	(755)
Net income	$ 169,503	$ 222,630

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY (UNAUDITED)
(in thousands)

	Total Members' Equity
Balance at December 31, 2022	$ 593,230
Net income	169,503
Distributions	(74,500)
Equity compensation	1,294
Balance at June 30, 2023	$ 689,527
Balance at December 31, 2021	$ 278,699
Net income	222,630
Distributions	(91,337)
Equity compensation	3,764
Contributions	65,000
Balance at June 30, 2022	$ 478,756

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	Six months ended June 30,	
	2023	**2022**
Cash flows from operating activities		
Net income	$ 169,503	$ 222,630
Adjustments to reconcile net income to cash provided by operating activities		
Depreciation, depletion and amortization	60,888	31,382
(Gain) loss on derivative instruments	(15,742)	72,857
Cash receipts (payments) on settlement of derivative contracts, net	7,245	(53,755)
Debt issuance costs amortization	202	186
Loss on contingent consideration	—	(8,111)
Equity based compensation	1,294	3,763
(Gain) loss on sale of assets	(1)	22
Settlement of asset retirement obligations	(79)	(49)
Changes in operating assets and liabilities (decreasing) increasing cash:		
Accounts receivable, inventories, other assets	59,643	(53,180)
Revenue payable	(2,675)	7,289
Accounts payable and accrued liabilities	(5,133)	4,902
Net cash provided by operating activities	275,145	227,936
Cash flows from investing activities		
Capital expenditures for oil and natural gas properties	(182,427)	(82,873)
Capital expenditures for other property and equipment	(4,953)	(3,891)
Acquisition of assets	(468)	(91,082)
Acquisition of assets – related party	—	(37,428)
Proceeds from sales of oil and natural gas properties	—	2,305
Proceeds from sales of other property and equipment	36	18
Net cash used in investing activities	(187,812)	(212,951)
Cash flows from financing activities		
Distributions to members	(74,500)	(91,336)
Payment of other financing fees	(404)	—
Proceeds from long-term debt	7,000	—
Repayments of borrowings	—	(900)
Contributions from members	—	65,000
Net cash used in financing activities	(67,904)	(27,236)
Net increase (decrease) in cash and cash equivalents	19,429	(12,251)
Cash and cash equivalents, beginning of period	29,417	59,272
Cash and cash equivalents, end of period	$ 48,846	$ 47,021

The accompanying notes are an integral part of these financial statements.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Nature of Business

BCE-Mach III LLC ("the Company") was formed on December 28, 2019, as a limited liability company under the laws of the State of Delaware. On December 28, 2019, the Company entered into an LLC agreement with its initial member. The LLC agreement was amended and restated on March 25, 2021, to allow additional equity to be issued to certain employees of the Company. The Company wholly owns one subsidiary, BCE-Mach III Midstream Holdings LLC. On April 9, 2020, the Company closed on an acquisition and operations subsequently began for the Company. The Company owns and operates producing wells and undeveloped acreage primarily in Oklahoma and Texas. The Company also owns gas gathering lines, gas processing facilities, and saltwater disposal facilities.

2. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The unaudited consolidated financial statements included herein were prepared fromrecords of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP") and include accounts of our wholly owned subsidiary. Intercompany accounts and transactions have been eliminated upon consolidation. These financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2022. Results for interim periods are not necessarily indicative of results to be expected for the full year ending December 31, 2023. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP 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. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the fair value determination of acquired assets and liabilities, equity based compensation, the fair value of contingent consideration, and the fair value estimates of commodity derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for credit losses when the Company believes collection is doubtful. The Company extends credit to joint interest owners and generally does not require collateral. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for credit losses. At June 30, 2023 and December 31, 2022, the Company's allowance for credit losses was not material.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments in the statement of operations.

Oil and Natural Gas Operations

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities, which are expensed as incurred. Capitalized costs are depreciated using the unit-of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $6.44 and $4.04 for the six months ended June 30, 2023 and 2022, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $55.9 million and $27.8 for the six months ended June 30, 2023 and 2022, respectively.

Under the full cost method, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each year. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the Internal Revenue Service ("IRS") recognition of the Company as a flow-through entity. No impairments on proved oil and natural gas properties were recorded for the six months ended June 30, 2023 and 2022.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

assigned. As of June 30, 2023, and December 31, 2022, the Company had no properties excluded from the full cost pool. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas, and natural gas liquids (“NGL”) reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Other Property and Equipment, Net

Other property and equipment primarily consists of a gathering system, processing plant, and salt water disposal system. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 2 to 37 years. Depreciation expense for other property and equipment was $2.8 million and $2.0 million for the six months ended June 30, 2023 and 2022, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets’ carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment of other property and equipment was recorded for the six months ended June 30, 2023 or 2022.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production and midstream equipment not placed in service as of June 30, 2023 and December 31, 2022. The Company’s production equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units, as well as pipe for midstream operations.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $1.4 million, net of accumulated amortization of $1.0 million as of June 30, 2023. As of December 31, 2022, other assets include capitalized costs related to the credit facility of $1.0 million, net of accumulated amortization of $0.8 million. These costs are being amortized over the term of the credit facility and are reported as interest expense on the Company’s statement of operations.

Income Taxes

The Company is an LLC taxed as a partnership, and any associated tax liability is the responsibility of the individual members of the LLC. Accordingly, no provision for income taxes has been made in these financial statements.

The Company disallows the recognition of tax positions not deemed to meet a “more-likely-than not” threshold of being sustained by the applicable tax authority. The Company’s policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company has not recognized any potential interest or penalties in its financial statements for the six months ended June 30, 2023. The Company’s tax years 2022, 2021, and 2020 remain open for examination by state authorities.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction or salt water disposal began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO for the six months ended (in thousands):

	June 30, 2023	June 30, 2022
Asset retirement obligation at beginning of period	$ 52,359	$ 25,620
Liabilities assumed in acquisitions	—	18,397
Liabilities incurred	109	1,009
Liabilities settled	(49)	(9)
Liabilities revised	9	141
Accretion expense	2,164	1,529
Asset retirement obligation at end of period	$ 54,592	$ 46,687

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 8. Derivative Contracts, for the Company's management of price volatility.

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statement of operations.

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGL are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statement of operations.

Midstream Revenue and Product Sales

The Company's gathering and processing revenue is generated from owned gathering and compression systems and processing plants acquired in the Company's acquisitions. The Company charges a gathering, compression, processing rate per MMBtu transported through the gathering system and processing plant. The Company also gathers and disposes of salt water from producing wells through an owned pipeline system and disposal wells. The Company charges a fixed rate per barrel for disposal.

Product sales are generated from the Company's sale of natural gas, oil and NGL production purchased from third parties and subsequently gathered and processed through the Company's owned midstream facilities. Product sales includes activity from certain third-party percent-of-proceeds contracts where the Company keeps a contractually based percentage of proceeds from the sale of natural gas and NGL production, as payment for processing natural gas from the third parties. The costs of buying natural gas, oil and NGL production from third party shippers are included as costs of product sales on the statement of operations.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company 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. Each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of Presentation and Summary of Significant Accounting Policies (cont.)

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the six months ended June 30, 2023, two purchasers each accounted for more than 10% of the Company's revenue: Phillips 66 Company (52.0%) and NextEra Energy Marketing, LLC (16.7%). For the six months ended June 30, 2022, four purchasers each accounted for more than 10% of the Company's revenue: Hinkle Oil and Gas Inc. (27.9%); Phillips 66 Company (20.2%); NextEra Energy Marketing, LLC (16.5%), and OneOK Hydrocarbon L.P. (10.5%). The Company's receivables as of June 30, 2023, and December 31, 2022, from oil and gas sales are concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

As of June 30, 2023, the Company had two customers that represented approximately 30% and 12%, respectively, of our total joint interest receivables. As of December 31, 2022, the Company had one customer that represented approximately 21% of our total joint interest receivables.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Six Months Ended June 30,	
	2023	2022
Revenues:		
Oil	$ 208,086	$ 218,867
Natural gas	69,699	129,591
NGL	34,544	59,028
Gross oil, natural gas, and NGL sales	312,329	407,486
Transportation, gathering and marketing	284	956
Net oil, natural gas, and NGL sales	$ 312,613	$ 408,442

Recent Accounting Pronouncements Adopted

In June 2016, the FASB issued Accounting Standards Update 2016-13, "Financial Instrument-Credit Losses: Measurement of Credit Losses on Financial Instruments," which amends reporting guidance on credit loses for certain financial instruments. The Company's primary risk for credit losses related to its receivables from joint interest owners in our operated oil and natural gas wells. This guidance is effective for periods after December 15, 2022, and the Company implemented it effective January 1, 2023, with no material impacts to the financial statements.

3. Supplemental Cash Flow Information

Supplemental disclosures to the statement of cash flows are presented below (in thousands):

	Six months ended June,	
	2023	2022
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 3,517	$ 1,703
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ (2,078)	$ 28,714
Asset retirement cost capitalized	$ 109	$ 1,009
Right-of-use assets obtained in exchange for lease liabilities	$ 4,872	$ 14,936

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

4. Property and Equipment

The Company’s property and equipment consists of the following (in thousands):

	June 30, 2023	December 31, 2022
Oil and natural gas properties		
Proved properties	$ 939,516	$ 749,934
Accumulated depreciation and depletion	(195,445)	(139,514)
Oil and natural gas properties, net	744,071	610,420
Other property and equipment		
Gas gathering system	24,469	22,366
Gas processing plants	34,392	33,858
Water disposal assets	23,142	21,029
Other assets	5,012	4,872
Total other property and equipment	87,015	82,125
Accumulated depreciation, depletion and amortization	(11,964)	(9,198)
Total other property and equipment, net	$ 75,051	$ 72,927

5. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	June 30, 2023	December 31, 2022
Operating expenses	$ 11,317	$ 10,198
Capital expenditures	18,762	37,375
Payroll costs	3,033	2,450
Hedge settlements	613	898
Severance and other tax	2,253	3,662
Midstream shipper payable	1,100	5,157
General, administrative, and other	1,094	429
Total accrued liabilities	$ 38,172	$ 60,169

6. Long-Term Debt

On May 19, 2020, the Company entered into a credit agreement for a revolving credit facility (“the Credit Facility”) with a syndicate of banks, including MidFirst Bank (“MidFirst”), who serves as administrative agent and issuing bank. The Credit Facility provides for a maximum of $400.0 million, subject to commitments of $100.0 million as of June 30, 2023, and matures in May 2026. Outstanding obligations under the credit facility are secured by substantially all of the Company’s assets. The amount available to be borrowed under the Credit Facility is subject to a borrowing base that is redetermined semiannually each May and November in an amount determined by the lenders. As of June 30, 2023, and December 31, 2022, there was $91.9 million and $84.9 million, respectively, outstanding under the Credit Facility.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. Financial ratios the Company is required to maintain on a quarterly basis include the ratio of total debt to EBITDAX not greater than 3.25 and the ratio of current assets to current liabilities of no less than 1.0. As of June 30, 2023, and December 31, 2022, the Company was in compliance with all applicable covenants under the Credit Facility.

6. Long-Term Debt (cont.)

The Company entered into the third amendment to the credit agreement on January 27, 2023. The third amendment includes an excess cash threshold that sets a limit of the consolidated cash balance of the Company at $20.0 million. The consolidated cash balance is defined as the unrestricted cash held by the Company shown and on the balance sheet less cash set aside to pay royalty obligations, working interest obligations, production payments, vendor payments, suspense payments, severance and ad valorem taxes, payroll, payroll taxes, other taxes, and employee wage and benefits. Required payments will be made only when the Company experiences one or more of the following:

- Ratio of total debt to EBITDAX greater than 2.5 evaluated each fiscal quarter
- Liquidity is less than 20% of the borrowing base.
- An event of default or borrowing base deficiency occurs.

Outstanding borrowings under the credit agreement bear interest at a per annum rate that is equal to the SOFR rate (which is equal to the Term SOFR rate as published by the Chicago Mercantile Exchange, Inc., CME Group Inc. and their Affiliates or their successor as the administrator for Term SOFR two Business Days before commencement of such Interest Period, subject to SOFR adjustment periods one month: 0.10%, three months: 0.15%, and six months: 0.25%), plus the applicable margin. The applicable margin ranges from 2.00% to 3.00% in the case of the alternate base rate and from 3.25% to 4.25% in the case of SOFR, in each case depending on the amount of loans and letters of credit outstanding. The Company is obligated to pay a quarterly commitment fee of 0.50% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of June 30, 2023, and December 31, 2022, was 8.5% and 7.7%, respectively.

7. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These transactions are in the form of fixed price swaps. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 9, Fair Value Measurements for additional information regarding fair value measurements.

The following table summarizes the open financial derivative positions as of June 30, 2023, related to oil production:

Period	Volume (Mbbl)	Weighted Average Fixed Price
July – September 2023	193	$ 61.00

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

7. Derivative Contracts (cont.)

As of June 30, 2023, the Company has no natural gas volumes hedged due to offsetting swap positions of equal volumes.

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The following table presents the gross amounts of recognized derivative liabilities, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	June 30, 2023	December 31, 2022
Derivative contracts – current, gross	$ 1,869	$ 10,080
Netting arrangements	—	—
Derivative contracts – current liabilities, net	$ 1,869	$ 10,080

There were no recognized derivative assets at June 30, 2023 or December 31, 2022.

Gains and Losses. The following table presents the settlement and mark-to-market (“MTM”) gains and losses presented as a gain or loss on derivatives in the statement of operations (in thousands):

	Six months ended June 30,	
	2023	2022
Settlements on derivatives	$ 7,530	$ (56,122)
MTM gains (losses) on derivatives, net	8,212	(16,735)
Total gains (losses) on derivative contracts	$ 15,742	$ (72,857)

The following table presents the gains and losses recognized on oil and natural gas derivatives in the accompanying statement of operations (in thousands):

	Six months ended June 30,	
	2023	2022
Oil derivatives	$ 3,907	$ (42,644)
Natural gas derivatives	11,835	(30,213)
Total gains (losses) on derivative contracts, net	$ 15,742	$ (72,857)

8. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company’s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 — Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.

Level 3 — Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

8. Fair Value Measurements (cont.)

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

Contingent Overriding Royalty Interest. On January 15, 2020, the Company executed a purchase and sale agreement with Alta Mesa Holdings, LP ("AMH") for the sale of certain oil and gas assets in Oklahoma and Kingfisher Midstream LLC ("KFM") for the sale of midstream gathering and processing assets that primarily service the AMH oil and gas assets (the "AMH Acquisition"). On April 2, 2020, the Company entered into the first amendment to the purchase and sale agreement with AMH and KFM. As part of the first amendments to the purchase and sale agreement, consideration of a 5% contingent overriding royalty interest ("the ORRI") was reserved when certain conditions regarding the market price of oil are met. There is a maximum consideration payable of $25 million related to the ORRI, and the ORRI will be terminated at the earlier of $25 million paid out or three years from the date of the acquisition. The conditions for the ORRI to take effect are that the West Texas Intermediate futures price ("WTI") of oil trades at or above $45/Bbl for 15 consecutive trading days. The ORRI may also go out of effect after previously being in effect if WTI trades below $45/Bbl for 15 consecutive trading days. Payments relating to this liability for the six months ended June 30, 2022, were $8.1 million. During the year ending December 31, 2022, the Company reached the maximum consideration of $25 million, therefore no liability remains in relation to the ORRI.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2023 and December 31, 2022 (in thousands).

	Level 1	Level 2	Level 3	Fair Value
As of June 30, 2023				
Liabilities:				
Derivative Instruments	$ —	$ 1,869	$ —	$ 1,869
As of December 31, 2022				
Liabilities:				
Derivative Instruments	$ —	$ 10,080	$ —	$ 10,080

Fair Value on a Non-Recurring Basis

The Company determines the initial estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair values due to the short-term maturities of these instruments.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

8. Fair Value Measurements (cont.)

The carrying amount of the Company's credit facility approximates fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

9. Equity Compensation and Deferred Compensation Plan

As part of the Company's Amended and Restated LLC Agreement as of March 25, 2021, incentive units (Class B Units) were issued to certain employees as compensation for services to be rendered to the Company. In determining the appropriate accounting treatment, the Company considered the characteristics of the awards in terms of treatment as stock-based compensation. US GAAP generally requires that all equity awards granted to employees be accounted for at fair value and recognized as compensation cost over the vesting period.

The incentive units are subject to graded vesting over a period of 3 or 4 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units forfeits unvested incentive units upon ceasing to be an employee of the Company, excluding limited exceptions. The Company recognizes forfeitures as they occur. Holders of incentive units participate in distributions upon the Company meeting a certain requisite financial internal rate of return threshold as defined in the amended LLC agreement.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For awards granted for the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 53%
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 1.40%

On March 25, 2021, all 20,000 authorized incentive units were granted. Total non-cash compensation cost related to the incentive units was $1.3 million and $3.8 million for the six months ended June 30, 2023, and 2022, respectively. As of June 30, 2023, there was $1.3 million in unrecognized compensation cost related to incentive units, which is expected to be recognized over a weighted-average period of 0.5 years.

A summary of the incentive unit awards as of June 30, 2023, and 2022 is as follows:

	Class B units	Weighted Average Grant Date Fair Value
Unvested at December 31, 2021	10,333	$ 2,378.80
Vested	(3,665)	$ 2,378.80
Unvested at June 30, 2022	6,668	$ 2,378.80
Unvested at December 31, 2022	6,668	$ 2,378.80
Vested	(3,667)	$ 2,378.80
Unvested at June 30, 2023	3,001	$ 2,378.80

10. Commitments and Contingencies

Legal Matters. In the ordinary course of business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. The Company did not recognize any material liability as of June 30, 2023, or December 31, 2022. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

11. Leases

Nature of Leases

The Company has operating leases on an office space, various vehicles, and compressors with remaining lease durations in excess of one year. These leases have various expiration dates throughout 2026. The vehicles are used for field operations and leased from third parties. The Company recognizes right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses the U.S. 5 Year Treasury Rate in determining the present value of lease payments. Minor changes to the discount rate do not have a material impact to the calculation of the liability, therefore the Company will use this for all asset classes.

Future amounts due under operating lease liabilities as of June 30, 2023, were as follows (in thousands):

Remaining 2023	$ 6,820
2024	5,919
2025	1,271
2026	202
Total lease payments	$ 14,212
Less: imputed interest	(344)
Total	$ 13,868

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

11. Leases (cont.)

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the six months ended June 30, 2023, and 2022 (in thousands):

	Six months ended June 30,	
	2023	2022
Operating lease cost	$ 6,619	$ 2,642
Short-term lease cost	5,143	5,552
Total lease cost	$ 11,762	$ 8,194

The weighted-average remaining lease term as of June 30, 2023, was 1.4 years. The weighted-average discount rate used to determine the operating lease liability as of June 30, 2023, was 3.9%.

12. Members' Equity

The Company was formed with one member, BCE-Mach Holdings III LLC. Upon formation, the Company consisted of one class of common interests, that were all owned by the member. An amended and restated LLC agreement was executed on February 18, 2020, replacing BCE-Mach Holdings III LLC with BCE-Mach Intermediate Holdings III LLC as the sole initial member. Contributions from the member were $150.0 million for the year ended December 31, 2020. On March 25, 2021, per the amended and restated LLC agreement and the Class A-2 Issuance Agreement, the Company issued 150,000 Class A-1 Units to the initial member, and 1,349 Class A-2 Units to an employee of Mach Resources LLC ("MR") for service performed for the Company. Additionally, Class A-2 Units were granted to the employee on a quarterly basis throughout 2021. As of June 30, 2023, there were 3,504 total Class A-2 Units issued to the employee, which have substantially all the same rights as the initial member. In 2022, the Class A-2 Issuance Agreement was updated and there are no additional units being granted to the employee. As part of a long-term incentive plan for certain employees, 20,000 Class B Units were outstanding as of June 30, 2023. The Class B Units represent a non-voting interest in the Company that allows the holder to participate in distributions once the Company's Class A shares have met a certain requisite financial internal rate of return in accordance with the LLC agreement.

Distributions to the members were $74.5 million and $91.3 million for the six months ended June 30, 2023, and 2022, respectively. Contributions from the members were $65.0 million for the six months ended June 30, 2022. There were no contributions from the members for the six months ended June 30, 2023.

13. Related Parties

Management Services Agreement. Upon formation of the Company, the Company entered into a management services agreement ("MSA") with Mach Resources LLC ("MR"). Under the MSA, MR manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company distributes funding to MR for performance under the MSA. During the six months ended June 30, 2023, the Company paid MR $21.1 million, which was inclusive of $2.1 million in management fees. During the six months ended June 30, 2022, the Company paid MR $15.7 million, which was inclusive of $1.0 million in management fees. As of June 30, 2023, the Company has $0.3 million in prepaid assets with MR. As of December 31, 2022, the Company owed $0.4 million to MR.

BCE-Stack Development LLC. BCE-Stack Development LLC ("BCE-Stack") is an affiliate of the member, and previously was an owner of working and revenue interests in a subset of the Company's wells. BCE-Stack sold their interests in the wells to the Company on February 28, 2022. Cash paid for the properties was $37.4 million.

BCE-MACH III LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

13. Related Parties (cont.)

BCE-Mach LLC and BCE-Mach II LLC. BCE-Mach LLC and BCE-Mach II LLC are two related parties that also entered into a MSA with Mach Resources. These entities have shared ownership with the Company and operate primarily in different geographical locations than the Company. As of June 30, 2023, the Company owed these entities $1.1 million included in accounts payable. As of December 31, 2022, the Company had receivables from these related parties of approximately $0.7 million included in accounts receivable-joint interest and other.

14. Subsequent Events

The Company has evaluated its financial statements for subsequent events through August30, 2023 the date the financial statements were available to be issued to ensure that any subsequent events that met the criteria for recognition and disclosure in this report have been properly included.

BCE-Mach LLC Financial Statements and Report of Independent Certified Public Accountants

As of December 31, 2022 and 2021, and for the years ended December 31, 2022 and 2021

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

Members
BCE-Mach LLC

Opinion

We have audited the financial statements of BCE-Mach LLC (a Delaware limited liability company) (the "Company"), which comprise the balance sheets as of December 31, 2022 and 2021, and the related statements of operations, members' equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for opinion

We conducted our audits of the financial statements in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of matter

As discussed in Note 12 to the financial statements, the Company has adopted new accounting guidance related to the adoption of FASB Accounting Standards Codification 842, *Leases*, effective January 1, 2022. Our opinion is not modified with respect to this matter.

Responsibilities of management for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 31, 2023

BCE-MACH LLC
BALANCE SHEETS
(in thousands)

	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 30,266	$ 36,550
Accounts receivable – joint interest and other	10,941	9,966
Accounts receivable – oil, gas, and NGL sales	31,457	35,329
Inventories	12,518	7,266
Other current assets	403	395
Total current assets	85,585	89,506
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	515,790	501,923
Less: accumulated depreciation, depletion, amortization and impairment	(280,472)	(255,315)
Oil and natural gas properties, net	235,318	246,608
Other property, plant and equipment	96,292	94,125
Less: accumulated depreciation and impairment	(35,499)	(27,425)
Other property, plant and equipment, net	60,793	66,700
Other assets	8,326	8,004
Operating lease assets	2,496	—
Goodwill	2,674	2,674
Total assets	$ 395,192	$ 413,492
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 12,818	$ 3,496
Accrued liabilities	15,055	8,497
Revenue payable	34,860	36,484
Current portion of long-term debt	—	26,000
Short-term derivative contracts	9,339	31,018
Current portion of operating lease liabilities	1,117	—
Total current liabilities	73,189	105,495
Long-term debt	65,000	87,500
Asset retirement obligations	33,693	33,617
Other long-term liabilities	225	233
Long-term derivative contracts	—	6,582
Long-term portion of operating lease liabilities	1,379	—
Total long-term liabilities	100,297	127,932
Commitments and contingencies (Note 10)		
Members' equity	221,706	180,065
Total liabilities and members' equity	$ 395,192	$ 413,492

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
STATEMENTS OF OPERATIONS
(in thousands)

	Year ended December 31,	
	2022	**2021**
Revenue		
Oil, natural gas, and NGL sales	$ 233,644	$ 183,065
Loss on oil and natural gas derivatives, net	(42,334)	(59,959)
Total revenues	191,310	123,106
Operating expenses		
Gathering and processing	34,437	30,729
Lease operating expense	35,605	24,578
Production taxes	13,246	9,645
Depreciation, depletion, amortization and accretion – oil and natural gas	26,621	26,977
Depreciation and amortization – other	8,318	7,778
General and administrative	4,577	10,429
Total operating expenses	122,804	110,136
Income from operations	68,506	12,970
Other income (expense)		
Interest expense	(5,515)	(6,915)
Loss on debt extinguishment	(898)	—
Other expense, net	(452)	(1,356)
Total other expense	(6,865)	(8,271)
Net income	$ 61,641	$ 4,699

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
STATEMENT OF MEMBERS' EQUITY
(in thousands)

	Total Members' Equity
Balance as of December 31, 2020	$ 171,868
Equity compensation	3,498
Net income	4,699
Balance as of December 31, 2021	$ 180,065
Distributions	(20,000)
Net income	61,641
Balance as of December 31, 2022	$ 221,706

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31, 2022	Year ended December 31, 2021
Cash flows from operating activities		
Net income	$ 61,641	$ 4,699
Adjustments to reconcile net income to cash provided by operating activities		
Depreciation, depletion and amortization	34,939	34,755
Loss on derivative instruments	42,334	59,959
Cash payments on settlement of derivative contracts, net	(71,060)	(30,213)
Debt issuance costs amortization	1,994	1,561
Equity based compensation	—	3,498
Gain on sale of assets	(30)	(187)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable, inventories, other assets	(1,631)	(12,407)
Revenue payable	(1,624)	11,742
Accounts payable and accrued liabilities	7,872	(4,527)
Settlement of asset retirement obligations	(118)	(184)
Net cash provided by operating activities	74,317	68,696
Cash flows from investing activities		
Capital expenditures for oil and natural gas properties	(9,024)	(2,071)
Capital expenditures for other property and equipment	(2,722)	(3,225)
Proceeds from sales of other property and equipment	345	187
Net cash used in investing activities	(11,401)	(5,109)
Cash flows from financing activities		
Proceeds from borrowings	70,000	—
Repayment of borrowings	(118,500)	(44,000)
Debt issuance costs	(700)	—
Distributions to members	(20,000)	—
Net cash used in financing activities	(69,200)	(44,000)
Net (decrease) increase in cash and cash equivalents	(6,284)	19,587
Cash and cash equivalents, beginning of period	36,550	16,963
Cash and cash equivalents, end of period	$ 30,266	$ 36,550

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

1. Nature of Business

BCE-Mach LLC ("the Company") was formed on January 23, 2018 as a limited liability company under the laws of the State of Delaware. On March 29, 2018, the Company entered into an amended and restated limited liability company agreement (the "Operating Agreement") with two entities (the "Members", see Note 12 — Members' Equity), capitalizing the Company concurrent with its initial acquisitions of oil and natural gas properties and commencement of operations. Revenues and expenses are allocated to the Members based upon the provisions of the Company's Operating Agreement. The Company owns producing wells and undeveloped acreage primarily in Oklahoma and Kansas.

2. Basis of presentation and Summary of Significant Accounting Policies

Basis of Presentation

The financial statements included herein were prepared fromrecords of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP"). In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP 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. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, equity-based compensation, and the fair value estimates of commodity derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. The Company extends credit to joint interest owners and generally does not require collateral. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. There were no write offs for the year ended December 31, 2022. The Company wrote off $4.0 million in receivables from a joint interest partner for the year ended December 31, 2021 regarding billing for the Company's saltwater disposal system.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments for each period in the statements of operations.

Oil and Natural Gas Operations

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities. Capitalized costs are depreciated using the unit-of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $5.44 and $4.70 for the years ended December 31, 2022 and 2021, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $25.2 million and $25.5 million for the years ended December 31, 2022 and 2021, respectively.

Under the full cost method, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each quarter. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the Internal Revenue Service ("IRS") recognition of the Company as a flow-through entity. No impairment was recorded for the years ended December 31, 2022 and 2021, respectively.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. As of December 31, 2022 and 2021, there were no properties excluded from the full cost pool.

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and natural gas liquids ("NGL") reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Other Property and Equipment, Net

Other property and equipment primarily consists of compression assets. Additionally, other property and equipment includes computer equipment and software, vehicles, office furniture, and an office building for field operations. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from two to 32 years. Depreciation expense for other property and equipment was $8.3 million and $7.8 million for the years ended December 31, 2022 and 2021, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cashflows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment of other property and equipment was recorded for the years ended December 31, 2022 or 2021.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production equipment not placed in service as of December 31, 2022 and 2021. The Company's equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units. The inventory is primarily acquired for use in future drilling or repair operations.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $0.7 million, net of accumulated amortization of $0.1 million as of December 31, 2022. These costs are being amortized over the term of the credit facility and are reported as interest expense on the Company's statements of operations.

Income Taxes

The Company is an LLC taxed as a partnership, and any associated tax liability is the responsibility of the individual members of the LLC. Accordingly, no provision for income taxes has been made in these financial statements.

The Company disallows the recognition of tax positions not deemed to meet a "more-likely-than not" threshold of being sustained by the applicable tax authority. The Company's policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company has not recognized any potential interest or penalties in its financial statements for the year ended December 31, 2022. The Company's tax years 2018, 2019, 2020 and 2021 remain open for examination by state authorities.

Goodwill

Goodwill represents the excess of the purchase price of a business combination over the fair value of the net assets acquired and is tested for impairment at least annually. Such test includes an assessment of the qualitative factors that could indicate impairment, and if necessary, the quantitative analysis to determine the goodwill impairment. If the fair value of the reporting unit is less than the net book value, including goodwill, then the

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

goodwill is written down to the implied fair value of the goodwill through a charge to expense. The Company performed an annual impairment test as of December 31, 2022 and 2021. Based on this assessment, no impairment of goodwill was required.

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO as of December 31, 2022 and 2021 (in thousands):

	December 31, 2022	December 31, 2021
Asset retirement obligation at beginning of period	$ 33,617	$ 32,317
Liabilities incurred	481	—
Liabilities settled	(1,892)	(159)
Liabilities revised	22	—
Accretion expense	1,465	1,459
Asset retirement obligation at end of period	$ 33,693	$ 33,617

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 7. Derivative Contracts, for the Company's management of price volatility.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statements of operations.

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGLs are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statements of operations.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For our product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company 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. Each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the period ended December 31, 2022, five purchasers each accounted for more than 10% of the Company's revenue: NextEra Energy Marketing, LLC (34.0%); Southwest Energy, LP (23.8%); ONEOK Hydrocarbon, L.P. (13.0%); Sandridge Energy, Inc. (11.9%) and Coffeyville Resources, LLC (11.6%). For the period ended December 31, 2021, three purchasers each accounted for more than 10% of the Company's revenue: Southwest Energy L.P. (42.7%); NextEra Energy Marketing, LLC (28.0%); and ONEOK Hydrocarbon, L.P. (15.3%). The Company's receivables as of December 31, 2022 and 2021 from oil and gas sales are concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

As of December 31, 2022 and 2021, the Company had one customer that represented approximately 70.7% and 74.6%, respectively, of our total joint interest receivables.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Year ended	
	December 31, 2022	December 31, 2021
Revenues:		
Oil	$ 96,015	$ 85,777
Natural gas	99,922	63,114
Natural gas liquids	37,849	35,072
Gross oil, natural gas, and NGL sales	233,786	183,963
Transportation and marketing	(142)	(898)
Net oil, natural gas, and NGL sales	$ 233,644	$ 183,065

Recent Accounting Pronouncements Adopted

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)". ASU 2016-02 establishes a right of use "ROU" model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. All leases create an asset and a liability for the lessee and therefore recognition of those lease assets and lease liabilities is required by ASU 2016-02. When measuring lease assets and liabilities, payments to be made in optional extension periods should be included if the lessee is reasonably certain to exercise the option. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 will not impact the accounting or financial presentation of our mineral leases.

In July 2018, the FASB issued Accounting Standards Update 2018-11, "Leases (Topic 842): Targeted Improvements", which included the option to implement the standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings, as opposed to the modified retrospective transition method required when ASU 2016-02 was issued. This guidance is effective for periods after December 15, 2021 and the Company implemented effective January 1, 2022. See Note 11. Leases, for further discussion.

Recent Accounting Pronouncements Issued But Not Yet Adopted

In June 2016, the FASB issued Accounting Standards Update 2016-13, "Financial Instrument-Credit Losses: Measurement of Credit Losses on Financial Instruments," which amends reporting guidance on credit loses for certain financial instruments. The Company's primary risk for credit losses related to its receivables from joint interest owners in our operated oil and natural gas wells. This guidance is effective for periods after December 15, 2022. The Company is currently implementing it with no significant changes expected to the financial statements as the Company has no history of credit losses.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

3. Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below (in thousands):

	Year ended December 31,	
	2022	2021
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 4,418	$ 5,354
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ 6,114	$ 147
Right-of-use assets obtained in exchange for lease liabilities	$ 3,487	$ —

4. Property and Equipment

The Company's property and equipment consists of the following (in thousands):

	December 31, 2022	December 31, 2021
Oil and natural gas properties		
Proved properties	$ 515,790	$ 501,923
Accumulated depreciation, depletion, amortization and impairment	(280,472)	(255,315)
Oil and natural gas properties, net	235,318	246,608
Other property and equipment		
Compressors	88,802	86,508
Buildings	4,032	4,032
Vehicles	912	1,039
Office equipment	1,038	1,038
Land	904	904
Other assets	604	604
Total other property and equipment	96,292	94,125
Accumulated depreciation and impairment	(35,499)	(27,425)
Total other property and equipment, net	$ 60,793	$ 66,700

Capitalized internal costs were approximately $1.7 million and $1.5 million as of December 31, 2022 and 2021, respectively.

5. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	December 31, 2022	December 31, 2021
Lease operating expense	$ 5,356	$ 3,307
Capital expenditures	4,968	353
Payroll costs	2,033	1,704
General, administrative, and other	2,698	3,133
Total accrued liabilities	$ 15,055	$ 8,497

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

6. Long-Term Debt

The Company entered into a new revolving credit facility (“the credit facility”) on September 2, 2022 with a syndicate of banks, including MidFirst Bank who serves as sole book runner and lead arranger, maturing in September 2026. Outstanding obligations under the credit facility are secured by substantially all of the Company’s assets. The previous revolving credit facility was retired in September 2022 and the Company wrote off all unamortized loan origination costs, recognizing $0.9 million as loss on debt extinguishment.

The credit agreement provides for a revolving credit facility in the maximum of $200.0 million, subject to commitments of $100.0 million as of December 31, 2022. As of December 31, 2022, $65.0 million was outstanding under the credit facility and $5.0 million in outstanding letters of credit, which reduces the availability under the credit facility on a dollar-for-dollar basis. The amount available to be borrowed under the credit facility is subject to a borrowing base that is redetermined semiannually each May and November in an amount determined by the lenders.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. Financial ratios the Company is required to maintain on a quarterly basis include the ratio of total net debt to EBITDAX not greater than 3.25 and the ratio of current assets to current liabilities of no less than 1.0. As of December 31, 2022, the Company was in compliance with all applicable covenants under the credit facility.

Outstanding borrowings under the credit agreement bear interest at a per annum rate that is equal to the SOFR rate (which is equal to the Term SOFR rate as published by the Chicago Mercantile Exchange, Inc., CME Group Inc. and their affiliates or their successor as the administrator for Term SOFR two business days before commencement of the interest period, subject to SOFR adjustment periods one month: 0.10%, three months: 0.15%, and six months: 0.25%), plus the applicable margin. The applicable margin ranges from 3% to 4% depending on the amount of loans and letters of credit outstanding. The Company is obligated to pay a quarterly commitment fee of 0.50% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of December 31, 2022 was 7.43%.

7. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These transactions are in the form of fixed price swaps. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 8, Fair Value Measurements for additional information regarding fair value measurements.

The following table summarizes the open financial derivative positions as of December 31, 2022, related to oil production:

Period	Volume (Mbbl)	Weighted Average Fixed Price
January – March 2023	143	$ 41.35

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

7. Derivative Contracts (cont.)

The following table summarizes the open financial derivative positions as of December 31, 2022, related to natural gas production:

Period	Volume (Mmbtu)	Weighted Average Fixed Price
January – March 2023	1,957	$ 2.52

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The Company did not have any derivative assets as of December 31, 2022 and 2021.

The following table presents the gross amounts of recognized derivative liabilities, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	December 31, 2022	December 31, 2021
Derivative contracts – current, gross	$ 9,339	$ 31,018
Netting arrangements	—	—
Derivative contracts – current, net	$ 9,339	$ 31,018
Derivative contracts – long-term, gross	$ —	$ 6,582
Netting arrangements	—	—
Derivative contracts – long-term, net	$ —	$ 6,582

Gains and Losses. The following table presents the settlement and mark-to-market (“MTM”) gains and losses presented as a gain or loss on derivatives in the statements of operations (in thousands):

	Year ended	
	December 31, 2022	December 31, 2021
Settlements on derivatives	$ (70,595)	$ (32,349)
MTM gains (losses) on derivatives, net	28,261	(27,610)
Total losses on derivative contracts	$ (42,334)	$ (59,959)

The following table presents the gains and losses recognized on oil and natural gas derivatives in the accompanying statements of operations (in thousands):

	Year ended	
	December 31, 2022	December 31, 2021
Oil derivatives	$ (15,883)	$ (34,671)
Natural gas derivatives	(26,451)	(25,288)
Total losses on derivative contracts, net	$ (42,334)	$ (59,959)

8. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 — Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.

Level 3 — Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2022 and 2021 (in thousands):

	Level 1	Level 2	Level 3	Fair Value
As of December 31, 2021				
Liabilities:				
Derivative Instruments	$ —	$ 37,600	$ —	$ 37,600
As of December 31, 2022				
Liabilities:				
Derivative Instruments	$ —	$ 9,339	$ —	$ 9,339

Fair Value on a Non-Recurring Basis

The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

The Company determines the estimated grant date fair value of its incentive units and common member interests to be recognized as compensation cost using level 3 inputs. The significant inputs used to calculate fair value include enterprise value, market volatility and future exit event dates. See Note 9, Equity Compensation and Deferred Compensation Plan, for additional information.

8. Fair Value Measurements (cont.)

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair values due to the short-term maturities of these instruments.

The carrying amount of the Company's credit facility approximates fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

9. Equity Compensation and Deferred Compensation Plan

As part of the Company's LLC Agreement, incentive units (Class B Units) were issued to certain employees as compensation for services to be rendered to the Company. In determining the appropriate accounting treatment, the Company considered the characteristics of the awards in terms of treatment as stock-based compensation. US GAAP generally requires that all equity awards granted to employees be accounted for at fair value and recognized as compensation cost over the vesting period.

The incentive units are subject to graded vesting over a period of 3 or 4 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units forfeits unvested incentive units upon ceasing to be an employee of the Company, excluding limited exceptions. The Company recognizes forfeitures as they occur. Holders of incentive units will begin to participate in distributions upon the Company meeting a certain requisite financial internal rate of return threshold as defined in the LLC agreement.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For awards granted for the period ended December 31, 2018, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 40%;
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business; and
- a risk-free rate based on a U.S Treasury yield curve of 2.68%.

As of December 31, 2022, 19,300 of the 20,000 authorized incentive units had been granted. Total non-cash compensation cost related to the incentive units was $0.2 million for the year ended December 31, 2021. The Company did not recognize non-cash compensation for Class B Units for the year ended December 31, 2022. As of December 31, 2022, there is no material unrecognized compensation cost related to incentive units.

A summary of the incentive unit awards as of December 31, 2022 is as follows:

	Class B units	Weighted Average Grant Date Fair Value
Unvested at December 31, 2020	4,317	$ 773.50
Vested	(3,492)	$ 773.50
Unvested at December 31, 2021	825	$ 773.50
Vested	(825)	$ 773.50
Unvested at December 31, 2022	—	$ —

9. Equity Compensation and Deferred Compensation Plan (cont.)

Upon formation, the Company issued 8,000 Class A-2 Units to Mach Resources LLC ("Mach Resources"), an initial member. As part of the Company's Amended and Restated LLC Agreement as of March 25, 2021 and the Class A-2 Issuance Agreement, the Company issued an additional 2,866 Class A-2 Units to an employee of Mach Resources for services performed for the Company. Additionally, A-2 Units were issued on a quarterly basis for the year ended December 31, 2021 to the employee and vest on the grant date. There were no new awards granted for the year ended December 31, 2022. In accordance with US GAAP, the equity awards granted to the employee will be accounted for at fair value and recognized as compensation cost over the vesting period. There were 11,438 total A-2 Units granted and vested as of December 31, 2022.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For awards granted for the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 67%
- 5 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 0.98%

Non-cash compensation cost related to the Class A-2 Units was $0 and $3.3 million for the years ended December 31, 2022 and 2021, respectively. There were no unvested Class A-2 Units and no related unrecognized costs as of December 31, 2022.

10. Commitments and Contingencies

Legal Matters. In the ordinary course of business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. The Company did not recognize any material liability as of December 31, 2022. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

NGL Sales and Gas Transportation Commitments. The Company is party to a NGL sales contract, which includes certain NGL volume commitments in the event the Company elects not to reduce its committed quantity, at its option. To the extent the Company does not deliver NGL volumes in sufficient quantities to meet the commitment and does not elect to reduce its committed quantity, it would be required to pay a deficiency fee. The Company is currently delivering at least the minimum volumes. Additionally, the Company has natural gas firm transportation agreements terminating in 2024. For the years ended December 31, 2022 and 2021, the Company incurred approximately $3.0 million and $2.5 million, respectively, of transportation charges under these agreements.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

11. Leases

Effective January 1, 2022, the Company adopted and implemented ASU No. 2016-02, Leases (Topic 842). The new standard supersedes the previous lease guidance by requiring lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases. The Company adopted the new standard on a prospective basis using the simplified transition method permitted by ASU No. 2018-11, Leases (Topic 842): Targeted Improvements. No cumulative-effect adjustment to retained earnings was required upon adoption of the new standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. The Company elected the package of practical expedients permitted under the new standard, which among other things, allows for lease and non-lease components in a contract to be accounted for as a single lease component for all asset classes and the carry forward of historical lease classifications.

Nature of Leases

The Company has operating leases on vehicles with remaining lease durations in excess of one year. These leases have various expiration dates throughout 2026. The vehicles are used for field operations and leased from a third party. The Company recognizes a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses the U.S. 5 Year Treasury Rate in determining the present value of lease payments. Minor changes to the discount rate do not have a material impact to the calculation of the liability, therefore the Company will use this for all asset classes.

Future amounts due under operating lease liabilities as of December 31, 2022, were as follows (in thousands):

2023	$	1,166
2024		765
2025		535
2026		214
Total lease payments	$	2,680
Less: imputed interest		(184)
Total	$	2,496

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the year ended December 31, 2022 (in thousands):

Operating lease cost	$	1,007
Short-term lease cost		5,181
Total lease cost	$	6,188

The weighted-average remaining lease term as of December 31, 2022 was 2.8 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2022 was 3.62%.

12. Members' Equity

Upon formation, the Company issued 124,000 Class A-1 Units to BCE-Mach Holdings LLC and 8,000 Class A-2 Units to Mach Resources LLC. The Company issued 26,437 Class A-3 Units to BCE-Mach Holdings LLC and 313 Class A-3 Units to Mach Resources LLC for additional capital contributed throughout 2020. As part of the amended and restated LLC agreement holders of class A-3 Units are entitled to 100% of all distributions until a 1.0x return on invested capital has been met. On March 25, 2021, per the Operating Agreement, the Company issued 2,351 Class A-2 Units to an employee of Mach Resources for services performed for the Company. Additionally,

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

12. Members' Equity (cont.)

Class A-2 Units were granted to the employee on a quarterly basis throughout 2021. During 2021 there were 3,135 total Class A-2 Units issued to the employee, which have substantially all the same rights as the equity holders. In 2022, the Class A-2 Issuance Agreement was updated and there are no additional units being granted to the employee. As of December 31, 2022 there were 11,438 Class A-2 Units issued and outstanding.

As part of a long-term incentive plan for certain employees, 19,300 Class B Units were outstanding as of December 31, 2022 and December 31, 2021. The Class B Units represent a non-voting interest in the Company that allows the holder to participate in distributions once the Company's Class A shares have met a certain requisite financial internal rate of return in accordance with the LLC agreement.

13. Related Parties

Management Services Agreement. Upon formation of the Company, the Company entered into a management services agreement ("MSA") with one of its members, Mach Resources. Under the MSA, Mach Resources manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company distributes funding to Mach Resources for performance under the MSA. During the years ended December 31, 2022 and 2021, the Company paid Mach Resources $23.4 million and $25.6 million, respectively. As of December 31, 2022, the Company owed $0.3 million to Mach Resources. As of December 31, 2021, the Company had $0.1 million in prepaid assets with Mach Resources.

BCE-Mach II LLC and BCE-Mach III LLC. BCE-Mach II LLC and BCE-Mach III LLC are two related parties that also entered into a MSA with Mach Resources. These entities have shared ownership with the Company and operate primarily in different geographical locations than the Company. As of December 31, 2022 the Company has a payable to BCE-Mach III LLC for $1.3 million. As of December 31, 2021 the Company has a payable to BCE-Mach II LLC for $0.1 million and a receivable from BCE-Mach III LLC for $0.6 million.

14. Subsequent Events

The Company has evaluated its financial statements for subsequent events through March31, 2023, the date the financial statements were available to be issued to ensure that any subsequent events that met the criteria for recognition and disclosure in this report have been properly included.

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

The following tables provide historical cost information regarding the Company's oil and gas operations located entirely in the United States:

Capitalized Costs related to Oil and Gas Producing Activities

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Proved properties	$ 515,790	$ 501,923
Accumulated depreciation, depletion, amortization and impairment	(280,472)	(255,315)
Net capitalized costs	$ 235,318	$ 246,608

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Acquisition	$ —	$ —
Development	15,446	2,404
Exploratory	—	—
Costs incurred	$ 15,446	$ 2,404

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

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

Results of Operations for Producing Activities

The following table includes revenue and expenses related to the production and sale of oil, natural gas, and NGLs. It does not include any derivative activity, interest costs or general and administrative costs.

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Revenues	$ 233,644	$ 183,065
Production costs	(83,288)	(64,952)
Depreciation, depletion, amortization and accretion	(26,621)	(26,977)
Results of operations from producing activities	$ 123,735	$ 91,136

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. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved undeveloped reserves or PUDs. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the US GAAP. 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.

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 2).

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

The standardized measure does not represent management's estimate of our future cash flows or the fair 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 affected 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 Summary

All of the Company's reserves are located in the United States. The following table sets forth the changes in the Company's net proved reserves (including developed and undeveloped reserves) for the years ended December 31, 2022 and 2021. Reserves estimates as of December 31, 2022 were estimated by the independent petroleum consulting firm Cawley, Gillespie & Associates, Inc.

Proved Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	17.8	220.5	12.4	66.9
Revisions of previous estimates	(0.1)	39.1	4.0	10.4
Purchases in place	—	—	—	—
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(1.3)	(18.0)	(1.1)	(5.4)
December 31, 2021	16.4	241.6	15.3	71.9
Revisions of previous estimates	1.1	28.3	1.9	7.7
Purchases in place	—	—	—	—
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(1.0)	(15.8)	(1.0)	(4.6)
December 31, 2022	16.5	254.1	16.2	75.0

Proved Developed Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	11.9	168.2	9.8	49.7
December 31, 2021	12.3	210.9	13.6	61.0
December 31, 2022	11.7	212.0	13.8	60.8

Proved Undeveloped Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	5.9	52.3	2.6	17.2
December 31, 2021	4.1	30.7	1.7	10.9
December 31, 2022	4.8	42.1	2.4	14.2

In 2021, the 10.3 mmboe of upward revisions in proved reserves were the result of a combination of higher commodity prices (13.5 mmboe), PUD changes (-0.7 mmboe), production forecast revisions (-5.5 mmboe) and changes in lease operating expenses and product price differentials to reflect current market conditions (3.0 mmboe).

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS

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

In 2022, the 7.7 mmboe of upward revisions in proved reserves were the result of higher commodity prices (6.0 mmboe), PUD adds and deletions (1.9 mmboe) and changes to product pricing differentials and lease operating expenses to reflect current market conditions (-0.2 mmboe).

The following table sets forth the standardized measure of discounted future net cash flow from projected production of the Company's oil and natural gas reserves:

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves (in thousands)	**December 31, 2022**	**December 31, 2021**
Future cash inflows	$ 3,206,749	$ 1,926,393
Future costs:		
Production[(1)]	(1,086,699)	(561,429)
Development[(2)]	(241,007)	(157,953)
Income taxes	—	—
Future net cash flows	1,879,043	1,207,011
10% annual discount	(1,029,073)	(666,368)
Standardized measure	$ 849,970	$ 540,643

(1) Production costs include production severance taxes, ad valorem taxes and operating expenses.
(2) Development costs include plugging expenses, net of salvage and net capital investment.

Changes in Standardized Measure of Discounted Future Net Cash Flows (in thousands)	**For the Year Ended December 31, 2022**	**2021**
Standardized measure, beginning of period	$ 540,643	$ 258,406
Revisions of previous quantity estimates	98,988	88,731
Changes in estimated future development costs	30,957	13,398
Net changes in prices and production costs	301,637	191,879
Accretion of discount	54,064	25,841
Sales of oil and gas produced, net of production costs	(150,356)	(118,113)
Development costs incurred during the period	14,619	2,324
Change in timing of estimated future production and other	(40,582)	78,177
Standardized measure, end of period	$ 849,970	$ 540,643

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

Average oil prices used in the estimation of proved reserves and calculation of the standardized measure were $93.67 for 2022 and $66.56 for 2021. Average realized gas prices were $6.36 for 2022 and $3.60 for 2021. We used 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period.

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BCE-Mach LLC Unaudited Financial Statements

As of June 30, 2023 and December 31 2022 and for the six months ended June 30, 2023 and 2022

BCE-MACH LLC
BALANCE SHEETS (UNAUDITED)
(in thousands)

	June 30, 2023	December 31, 2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 23,441	$ 30,266
Accounts receivable – joint interest and other	11,860	10,941
Accounts receivable – oil, gas, and NGL sales	18,712	31,457
Inventories	13,776	12,518
Short-term derivative contracts	1,378	—
Other current assets	1,297	403
Total current assets	70,464	85,585
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	527,892	515,790
Less: accumulated depreciation, depletion, amortization and impairment	(292,424)	(280,472)
Oil and natural gas properties, net	235,468	235,318
Other property, plant and equipment	98,589	96,292
Less: accumulated depreciation and impairment	(39,953)	(35,499)
Other property, plant and equipment, net	58,636	60,793
Other assets	4,337	8,326
Operating lease assets	3,196	2,496
Goodwill	2,674	2,674
Total assets	$ 374,775	$ 395,192
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 6,033	$ 12,818
Accrued liabilities	10,455	15,055
Revenue payable	25,796	34,860
Short-term derivative contracts	—	9,339
Current portion of operating lease liabilities	1,463	1,117
Total current liabilities	43,747	73,189
Long-term debt	65,000	65,000
Asset retirement obligations	34,445	33,693
Other long-term liabilities	274	225
Long-term portion of operating lease liabilities	1,740	1,379
Total long-term liabilities	101,459	100,297
Commitments and contingencies (Note 10)		
Members’ equity	229,569	221,706
Total liabilities and members’ equity	$ 374,775	$ 395,192

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
STATEMENTS OF OPERATIONS (UNAUDITED)
(in thousands)

	Six months ended June 30, 2023	Six months ended June 30, 2022
Revenue		
Oil, natural gas, and NGL sales	$ 70,710	$ 121,364
Gain (loss) on oil and natural gas derivatives, net	6,048	(42,710)
Total revenues	76,758	78,654
Operating expenses		
Gathering and processing	13,928	16,746
Lease operating expense	20,514	16,565
Production taxes	3,644	6,875
Depreciation, depletion, and accretion – oil and natural gas	12,678	12,822
Depreciation and amortization – other	4,454	4,094
General and administrative	4,791	2,667
Total operating expenses	60,009	59,769
Income from operations	16,749	18,885
Other income (expense)		
Interest expense	(2,811)	(2,861)
Other income (expense), net	(4,075)	3,331
Total other income (expense)	(6,886)	470
Net income	$ 9,863	$ 19,355

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
STATEMENTS OF MEMBERS' EQUITY (UNAUDITED)
(in thousands)

	Total Members' Equity
Balance as of December 31, 2022	$ 221,706
Distributions	(2,000)
Net income	9,863
Balance as of June 30, 2023	$ 229,569
Balance as of December 31, 2021	$ 180,065
Net income	19,355
Balance as of June 30, 2022	$ 199,420

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	Six months ended June 30, 2023	Six months ended June 30, 2022
Cash flows from operating activities		
Net income	$ 9,863	$ 19,355
Adjustments to reconcile net income to cash provided by operating activities		
Depreciation and depletion	17,133	16,916
(Gain) loss on derivative instruments	(6,048)	42,710
Cash payments on settlement of derivative contracts	(6,889)	(34,744)
Debt issuance costs amortization	87	774
Loss on sale of assets	—	25
Settlement of asset retirement obligations	(52)	(118)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable, inventories, other assets	12,073	(17,807)
Revenue payable	(9,064)	12,316
Accounts payable and accrued liabilities	(1,736)	3,375
Net cash provided by operating activities	15,367	42,802
Cash flows from investing activities		
Capital expenditures for oil and natural gas properties	(17,895)	(1,460)
Capital expenditures for other property and equipment	(2,297)	(1,325)
Proceeds from sales of other property and equipment	—	285
Net cash used in investing activities	(20,192)	(2,500)
Cash flows from financing activities		
Repayment of borrowings	—	(30,500)
Distributions to members	(2,000)	—
Net cash used in financing activities	(2,000)	(30,500)
Net (decrease) increase in cash and cash equivalents	(6,825)	9,802
Cash and cash equivalents, beginning of period	30,266	36,550
Cash and cash equivalents, end of period	$ 23,441	$ 46,352

The accompanying notes are an integral part of these financial statements.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

1. Nature of Business

BCE-Mach LLC ("the Company") was formed on January 23, 2018 as a limited liability company under the laws of the State of Delaware. On March 29, 2018, the Company entered into an amended and restated LLC agreement with two entities (the "Members", see Note 12 — Members' Equity), capitalizing the Company concurrent with its initial acquisitions of oil and natural gas properties and commencement of operations. Revenues and expenses are allocated to the Members based upon the provisions of the Company's operating agreement. The Company owns producing wells and undeveloped acreage primarily in Oklahoma and Kansas.

2. Basis of presentation and Summary of Significant Accounting Policies

Basis of Presentation

The unaudited financial statements included herein were prepared fromrecords of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP"). These financial statements should be read in conjunction with the audited financial statements and notes thereto for the year ended December 31, 2022. Results for interim periods are not necessarily indicative of results to be expected for the full year ending December 31, 2023. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP 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. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, equity-based compensation, and the fair value estimates of commodity derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for credit losses when the Company believes collection is doubtful. The Company extends credit to joint interest owners and generally does not require collateral. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for credit losses. At June 30, 2023 and December 31, 2022, the Company's allowance for credit losses was not material.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments for each period in the statements of operations.

Oil and Natural Gas Operations

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities. Capitalized costs are depreciated using the unit-of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $5.13 and $5.09 for the six months ended June 30, 2023 and 2022, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $12.0 million and $12.1 million for the six months ended June 30, 2023 and 2022, respectively.

Under the full cost method, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each quarter. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the Internal Revenue Service ("IRS") recognition of the Company as a flow-through entity. No impairment was recorded for the six months ended June 30, 2023 and 2022.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. As of June 30, 2023 and December 31, 2022, there were no properties excluded from the full cost pool.

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and natural gas liquids ("NGL") reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Other Property and Equipment, Net

Other property and equipment primarily consists of compression assets. Additionally, other property and equipment includes computer equipment and software, vehicles, office furniture, and an office building for field operations. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 2 to 32 years. Depreciation expense for other property and equipment was $4.5 million and $4.1 million for the six months ended June 30, 2023 and 2022, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cashflows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment of other property and equipment was recorded for the six months ended June 30, 2023 or 2022.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production equipment not placed in service as of June 30, 2023 and December 31, 2022. The Company's equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units. The inventory is primarily acquired for use in future drilling or repair operations.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $0.7 million, net of accumulated amortization of $0.1 million as of June 30, 2023. As of December 31, 2022, other assets included costs related to the credit facility of $0.7 million, net of accumulated amortization of $0.1 million. These costs are being amortized over the term of the credit facility and are reported as interest expense on the Company's statements of operations.

Income Taxes

The Company is an LLC taxed as a partnership, and any associated tax liability is the responsibility of the individual members of the LLC. Accordingly, no provision for income taxes has been made in these financial statements.

The Company disallows the recognition of tax positions not deemed to meet a "more-likely-than not" threshold of being sustained by the applicable tax authority. The Company's policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company has not recognized any potential interest or penalties in its financial statements for the six months ended June 30, 2023 and 2022. The Company's tax years 2018, 2019, 2020, 2021, and 2022 remain open for examination by state authorities.

Goodwill

Goodwill represents the excess of the purchase price of a business combination over the fair value of the net assets acquired and is tested for impairment at least annually. Such test includes an assessment of the qualitative factors that could indicate impairment, and if necessary, the quantitative analysis to determine the goodwill

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

impairment. If the fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. The Company performed an annual impairment test as of December 31, 2022. Based on this assessment, no impairment of goodwill was required. There has been no triggering event for the six months ended June 30, 2023 that would indicate goodwill is required to be reassessed for impairment during the period.

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO for the six months ended (in thousands):

	June 30, 2023	June 30, 2022
Asset retirement obligation at beginning of period	$ 33,693	$ 33,617
Liabilities incurred	32	51
Liabilities settled	(84)	(898)
Liabilities revised	78	201
Accretion expense	726	738
Asset retirement obligation at end of period	$ 34,445	$ 33,709

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 7. Derivative Contracts, for the Company's management of price volatility.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statements of operations.

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGLs are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statements of operations.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For our product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company 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. Each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the six months ended June 30, 2023, four purchasers each accounted for more than 10% of the Company's revenue: Coffeyville Resources, LLC (40.5%); NextEra Energy Marketing, LLC (29.5%); Sandridge Energy, Inc. (11.4%); and One-OK Hydrocarbon, L.P. (10.3%). For the six months ended June 30, 2022, four purchasers each accounted for more than 10% of the Company's revenue: Southwest Energy L.P. (37.5%); NextEra Energy Marketing, LLC (29.0%); Sandridge Energy, Inc. (12.8%); and One-Ok Hydrocarbon, L.P. (12.2%). The Company's receivables as of June 30, 2023 and December 31, 2022 from oil and gas sales are concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

As of June 30, 2023 and December 31, 2022, the Company had one customer that represented approximately 65.8% and 70.7%, respectively, of our total joint interest receivables.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Six months ended	
	June 30, 2023	June 30, 2022
Revenues:		
Oil	$ 38,595	$ 52,478
Natural gas	21,450	47,388
Natural gas liquids	11,614	21,681
Gross oil, natural gas, and NGL sales	71,659	121,547
Transportation and marketing	(948)	(183)
Net oil, natural gas, and NGL sales	$ 70,710	$ 121,364

Recent Accounting Pronouncements Adopted

In June 2016, the FASB issued Accounting Standards Update 2016-13, "Financial Instrument-Credit Losses: Measurement of Credit Losses on Financial Instruments," which amends reporting guidance on credit loses for certain financial instruments. The Company's primary risk for credit losses related to its receivables from joint interest owners in our operated oil and natural gas wells. This guidance is effective for periods after December 15, 2022 and the Company implemented it effective January 1, 2023 with no material impacts to the financial statements.

3. Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below (in thousands):

	Six months ended June,	
	2023	2022
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 2,724	$ 2,087
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ (6,416)	$ (97)
Right-of-use assets obtained in exchange for lease liabilities	$ 1,213	$ 2,362

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

4. Property and Equipment

The Company's property and equipment consists of the following (in thousands):

	June 30, 2023	December 31, 2022
Oil and natural gas properties		
Proved properties	$ 527,892	$ 515,790
Accumulated depreciation, depletion, amortization and impairment	(292,424)	(280,472)
Oil and natural gas properties, net	235,468	235,318
Other property and equipment		
Compressors	91,034	88,802
Buildings	4,032	4,032
Vehicles	912	912
Office equipment	1,103	1,038
Land	904	904
Other assets	604	604
Total other property and equipment	98,589	96,292
Accumulated depreciation and impairment	(39,953)	(35,499)
Total other property and equipment, net	$ 58,636	$ 60,793

Capitalized internal costs were approximately $1.8 million and $1.7 million as of June 30, 2023 and December 31, 2022, respectively.

5. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	June 30, 2023	December 31, 2022
Lease operating expense	$ 6,100	$ 5,356
Capital expenditures	524	4,968
Payroll costs	2,473	2,033
General, administrative, and other	1,358	2,698
Total accrued liabilities	$ 10,455	$ 15,055

6. Long-Term Debt

The Company entered into a revolving credit facility ("the Credit Facility") on September 2, 2022 with a syndicate of banks, including MidFirst Bank who serves as sole book runner and lead arranger, maturing in September 2026. Outstanding obligations under the Credit Facility are secured by substantially all of the Company's assets. The previous revolving Credit Facility was retired in September 2022 and the Company wrote off all unamortized loan origination costs, recognizing $0.9 million as loss on debt extinguishment in the third quarter of 2022.

The credit agreement provides for a revolving Credit Facility in the maximum of $200.0 million, subject to commitments of $100.0 million as of June 30, 2023. As of June 30, 2023, $65.0 million was outstanding under the Credit Facility and $5.0 million in outstanding letters of credit, which reduces the availability under the Credit Facility on a dollar-for-dollar basis. The amount available to be borrowed under the Credit Facility is subject to a borrowing base that is redetermined semiannually each May and November in an amount determined by the lenders.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

6. Long-Term Debt (cont.)

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. Financial ratios the Company is required to maintain on a quarterly basis include the ratio of total net debt to EBITDAX not greater than 3.25 and the ratio of current assets to current liabilities of no less than 1.0. As of June 30, 2023 and December 31, 2022, the Company was in compliance with all applicable covenants under the Credit Facility.

Outstanding borrowings under the credit agreement bear interest at a per annum rate that is equal to the SOFR rate (which is equal to the Term SOFR rate as published by the Chicago Mercantile Exchange, Inc., CME Group Inc. and their Affiliates or their successor as the administrator for Term SOFR two Business Days before commencement of such Interest Period, subject to SOFR adjustment periods one month: 0.10%, three months: 0.15%, and six months: 0.25%), plus the applicable margin. The applicable margin ranges from 3% to 4% depending on the amount of loans and letters of credit outstanding. The Company is obligated to pay a quarterly commitment fee of 0.50% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of June 30, 2023 and December 31, 2022 was 8.5% and 7.4%, respectively.

7. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These

transactions are in the form of fixed price swaps. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 8, Fair Value Measurements for additional information regarding fair value measurements.

As of June 30, 2023 the Company has no oil volumes hedged due to offsetting swap positions of equal volumes.

The following table summarizes the open financial derivative positions as of June 30, 2023, related to natural gas production:

Period	Volume (Mmbtu)	Weighted Average Fixed Price
July – October 2023	962	$ 3.29

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

7. Derivative Contracts (cont.)

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The following table presents the gross amounts of recognized derivative assets, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	June 30, 2023	December 31, 2022
Derivative contracts – current, gross	$ 1,378	$ —
Netting arrangements	—	—
Derivative contracts – current assets, net	$ 1,378	$ —

The following table presents the gross amounts of recognized derivative liabilities, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	June 30, 2023	December 31, 2022
Derivative contracts – current, gross	$ —	$ 9,339
Netting arrangements	—	—
Derivative contracts – current liabilities, net	$ —	$ 9,339

Gains and Losses. The following table presents the settlement and mark-to-market ("MTM") gains and losses presented as a gain or loss on derivatives in the statements of operations (in thousands):

	Six months ended June 30,	
	2023	2022
Settlements on derivatives	$ (4,669)	$ (36,337)
MTM gains (losses) on derivatives, net	10,717	(6,373)
Total gains (losses) on derivative contracts	$ 6,048	$ (42,710)

The following table presents the gains and losses recognized on oil and natural gas derivatives in the accompanying statements of operations (in thousands):

	Six months ended June 30,	
	2023	2022
Oil derivatives	$ 2,621	$ (20,783)
Natural gas derivatives	3,427	(21,927)
Total gains (losses) on derivative contracts, net	$ 6,048	$ (42,710)

8. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs

8. Fair Value Measurements (cont.)

are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 —	Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.
Level 2 —	Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.
Level 3 —	Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2023 and December 31, 2022 (in thousands).

	Level 1	Level 2	Level 3	Fair Value
As of June 30, 2023				
Assets:				
Derivative Instruments	$ —	$ 1,378	$ —	$ 1,378
As of December 31, 2022				
Liabilities:				
Derivative Instruments	$ —	$ 9,339	$ —	$ 9,339

Fair Value on a Non-Recurring Basis

The Company determines the initial estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

The Company determines the estimated grant date fair value of its incentive units and common member interests to be recognized as compensation cost using level 3 inputs. The significant inputs used to calculate fair value include enterprise value, market volatility and future exit event dates. See Note 9, Equity Compensation and Deferred Compensation Plan, for additional information.

8. Fair Value Measurements (cont.)

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair values due to the short-term maturities of these instruments.

The carrying amount of the Company's credit facility approximates fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

9. Equity Compensation and Deferred Compensation Plan

As part of the Company's LLC Agreement, incentive units (Class B Units) were issued to certain employees as compensation for services to be rendered to the Company. In determining the appropriate accounting treatment, the Company considered the characteristics of the awards in terms of treatment as stock-based compensation. US GAAP generally requires that all equity awards granted to employees be accounted for at fair value and recognized as compensation cost over the vesting period.

The incentive units are subject to graded vesting over a period of 3 or 4 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units forfeits unvested incentive units upon ceasing to be an employee of the Company, excluding limited exceptions. The Company recognizes forfeitures as they occur. Holders of incentive units will begin to participate in distributions upon the Company meeting a certain requisite financial internal rate of return threshold as defined in the LLC agreement.

As of June 30, 2023, 19,300 of the 20,000 authorized incentive units had been granted. As of June 30, 2023 there were no unvested units or unrecognized compensation costs. The Company did not recognize non-cash compensation for Class B Units for the three and six months ended June 30, 2023 or 2022. As of June 30, 2023, there is no material unrecognized compensation cost related to incentive units.

10. Commitments and Contingencies

Legal Matters. In the ordinary course of business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. The Company did not recognize any material liability as of June 30, 2023. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

NGL Sales and Gas Transportation Commitments. The Company is party to a NGL sales contract, which includes certain NGL volume commitments. To the extent the Company does not deliver NGL volumes in sufficient quantities to meet the commitment, it would be required to pay a deficiency fee. The Company is currently delivering at least the minimum volumes. Additionally, the Company has natural gas firm transportation agreements terminating in 2024. For the six months ended June 30, 2023 and 2022, the Company incurred approximately $1.6 million and $1.6 million, respectively, of transportation charges under these agreements.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

11. Leases

Nature of Leases

The Company has operating leases on compressors, an office space, and vehicles with remaining lease durations in excess of one year. These leases have various expiration dates throughout 2026. The vehicles are used for field operations and leased from a third party. The Company recognizes a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses the U.S. 5 Year Treasury Rate in determining the present value of lease payments. Minor changes to the discount rate do not have a material impact to the calculation of the liability, therefore the Company will use this for all asset classes.

Future amounts due under operating lease liabilities as of June 30, 2023, were as follows (in thousands):

Remaining 2023	$	850
2024		1,336
2025		941
2026		214
Total lease payments	$	3,341
Less: imputed interest		(138)
Total	$	3,203

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the six months ended June 30, 2023 and 2022 (in thousands):

	Six months ended June 30,			
	2023		2022	
Operating lease cost	$	847	$	326
Short-term lease cost		3,140		2,498
Total lease cost	$	3,987	$	2,824

The weighted-average remaining lease term as of June 30, 2023 was 2.4 years. The weighted-average discount rate used to determine the operating lease liability as of June 30, 2023 was 3.65%.

12. Members' Equity

Upon formation, the Company issued 124,000 Class A-1 Units to BCE-Mach Holdings LLC and 8,000 Class A-2 Units to Mach Resources LLC. The Company issued 26,437 Class A-3 Units to BCE-Mach Holdings LLC and 313 Class A-3 Units to Mach Resources LLC for additional capital contributed throughout 2020. As part of the amended and restated LLC agreement holders of class A-3 Units are entitled to 100% of all distributions until a 1.0x return on invested capital has been met. On March 25, 2021, per the Amended and Restated LLC Agreement, the Company issued 2,351 Class A-2 Units to an employee of MR for services performed for the Company. Additionally, Class A-2 Units were granted to the employee on a quarterly basis throughout 2021. During 2021 there were 3,135 total Class A-2 Units issued to the employee, which have substantially all the same rights as the equity holders. In 2022, the Class A-2 Issuance Agreement was updated and there are no additional units being granted to the employee. As of June 30, 2023 there were 11,438 Class A-2 Units issued and outstanding.

As part of a long-term incentive plan for certain employees, 19,300 Class B Units were outstanding as of June 30, 2023 and 2022. The Class B Units represent a non-voting interest in the Company that allows the holder to participate in distributions once the Company's Class A shares have met a certain requisite financial internal rate of return in accordance with the LLC agreement.

BCE-MACH LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

13. Related Parties

Management Services Agreement. Upon formation of the Company, the Company entered into a management services agreement ("MSA") with one of its Members, Mach Resources LLC ("MR"). Under the MSA, MR manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company distributes funding to MR for performance under the MSA. During the six months ended June 30, 2023, the Company paid MR $12.2 million, which was inclusive of $1.3 million in management fees. During the six months ended June 30, 2022, the Company paid MR $11.8 million, which was inclusive of $0.6 million in management fees. As of June 30, 2023 the Company had $0.5 million in prepaid assets with MR. As of December 31, 2022, the Company owed $0.3 million to MR.

BCE-Mach II LLC and BCE-Mach III LLC. BCE-Mach II LLC and BCE-Mach III LLC are two related parties that also entered into a MSA with Mach Resources. These entities have shared ownership with the Company and operate primarily in different geographical locations than the Company. As of June 30, 2023 the Company has receivables from these related parties for approximately $0.2 million included in accounts receivable-joint interest and other. As of December 31, 2022 the Company had payables to these related parties for approximately $1.3 million included in accounts payable.

14. Subsequent Events

The Company has evaluated its financial statements for subsequent events through August30, 2023 the date the financial statements were available to be issued to ensure that any subsequent events that met the criteria for recognition and disclosure in this report have been properly included.

BCE-Mach II LLC Financial Statements and Report of Independent Certified Public Accountants

As of December 31, 2022 and 2021, and for the years ended December 31, 2022 and 2021

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

Members
BCE-Mach II LLC

Opinion

We have audited the financial statements of BCE-Mach II LLC (a Delaware limited liability company) (the "Company"), which comprise the balance sheets as of December 31, 2022 and 2021, and the related statements of operations, members' equity, and cash flows for the years then ended, and the related notes to the financial statements.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for opinion

We conducted our audits of the financial statements in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of matter

As discussed in Note 12 to the financial statements, the Company has adopted new accounting guidance related to the adoption of FASB Accounting Standards Codification 842, *Leases*, effective January 1, 2022. Our opinion is not modified with respect to this matter.

Responsibilities of management for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 31, 2023

BCE-MACH II LLC
BALANCE SHEETS
(in thousands)

	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 19,303	$ 29,588
Accounts receivable – joint interest and other	9,586	8,041
Accounts receivable – oil, gas, and NGL sales	10,326	10,715
Short-term derivative contracts	737	—
Inventories	1,154	1,171
Other current assets	1,449	513
Total current assets	42,555	50,028
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	82,989	68,948
Less: accumulated depreciation, depletion, and impairment	(38,024)	(34,575)
Oil and natural gas properties, net	44,965	34,373
Other property, plant and equipment	11,418	11,409
Less: accumulated depreciation	(2,102)	(1,435)
Other property, plant and equipment, net	9,316	9,974
Other assets	235	370
Operating lease assets	1,113	—
Total assets	$ 98,184	$ 94,745
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 1,940	$ 1,951
Accrued liabilities	3,212	2,071
Revenue payable	22,952	21,604
Current portion of long-term debt	—	3,500
Short-term derivative contracts	—	1,397
Current portion of operating lease liabilities	374	—
Total current liabilities	28,478	30,523
Long-term debt	17,100	18,100
Asset retirement obligations	18,499	16,469
Other long-term liabilities	524	571
Long-term portion of operating lease liabilities	739	—
Total long-term liabilities	36,862	35,140
Commitments and contingencies (Note 11)		
Members' equity	32,844	29,082
Total liabilities and members' equity	$ 98,184	$ 94,745

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
STATEMENTS OF OPERATIONS
(in thousands)

	Years Ended December 31,	
	2022	**2021**
Revenue		
Oil, natural gas, and NGL sales	$ 71,388	$ 44,845
Loss on oil and natural gas derivatives, net	(3,535)	(4,494)
Gathering revenue	459	541
Total revenues	68,312	40,892
Operating expenses		
Gathering and processing	5,966	3,787
Gathering operating expense	461	424
Lease operating expense	13,721	10,755
Production taxes	4,123	2,273
Depreciation, depletion, amortization and accretion – oil and natural gas	4,487	4,284
Depreciation and amortization – other	679	654
General and administrative	(2,551)	743
Total operating expenses	26,886	22,920
Income from operations	41,426	17,972
Other (expense) income		
Interest expense	(951)	(813)
Other income, net	60	3,578
Total other (expense) income	(891)	2,765
Net income	$ 40,535	$ 20,737

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
STATEMENT OF MEMBERS' EQUITY
(in thousands)

	Total Members' Equity
Balance at December 31, 2020	$ 10,314
Net income	20,737
Equity compensation	4,031
Distributions	(6,000)
Balance at December 31, 2021	$ 29,082
Net income	40,535
Equity compensation	674
Distributions	(37,447)
Balance at December 31, 2022	$ 32,844

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,	
	2022	2021
Cash flows from operating activities		
Net income	$ 40,535	$ 20,737
Adjustments to reconcile net loss to cash provided by operating activities		
Depreciation, depletion and amortization	5,166	4,938
Loss on derivative instruments	3,535	4,494
Cash payments on settlement of derivative contracts, net	(5,819)	(2,692)
Debt issuance costs amortization	134	134
Equity based compensation	674	4,031
Gain on sale of assets	(19)	(68)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable, inventories, other assets	(2,108)	(5,823)
Revenue payable	1,348	2,779
Accounts payable and accrued liabilities	1,328	(16)
Settlement of asset retirement obligations	(39)	(30)
Net cash provided by operating activities	44,735	28,484
Cash flows from investing activities		
Capital expenditures for oil and natural gas properties	(1,070)	(970)
Capital expenditures for other property and equipment	(48)	(439)
Divestiture of assets	—	242
Acquisition of assets	(12,001)	—
Proceeds from sales of other property and equipment	46	—
Net cash used in investing activities	(13,073)	(1,167)
Cash flows from financing activities		
Repayments of borrowings	(4,500)	(4,400)
Distributions to members	(37,447)	(6,000)
Net cash used in financing activities	(41,947)	(10,400)
Net (decrease) increase in cash and cash equivalents	(10,285)	16,917
Cash and cash equivalents, beginning of period	29,588	12,671
Cash and cash equivalents, end of period	$ 19,303	$ 29,588

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS

1. Nature of Business

BCE-Mach II LLC ("the Company") was formed on October 26, 2018 as a limited liability company under the laws of the State of Delaware. On July 9, 2019, the Company entered into the original limited liability company agreement with its initial member (the "LLC agreement"). An employee was admitted as a member of the Company in the LLC agreement as amended and restated on March 25, 2021. On September 13, 2019, and September 27, 2019, the Company closed on two acquisitions and operations subsequently began. The Company owns and operates producing wells and undeveloped acreage primarily in the Anadarko Basin in both Texas and Oklahoma.

2. Basis of presentation and Summary of Significant Accounting Policies

Basis of Presentation

The financial statements included herein were prepared fromrecords of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP"). In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP 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. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the fair value determination of acquired assets and liabilities, equity based compensation, and the fair value estimates of commodity derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. The Company extends credit to joint interest owners and generally does not require collateral. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2022 or 2021.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments for each period in the statements of operations.

Oil and Natural Gas Operations

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities, which are expensed as incurred. Capitalized costs are depreciated using the unit-of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $1.82 and $1.86 for the years ended December 31, 2022 and 2021, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $3.5 million and $3.4 million for the years ended December 31, 2022 and 2021, respectively.

Under the full cost method, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each quarter. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the Internal Revenue Service ("IRS") recognition of the Company as a flow-through entity. No impairments on proved oil and natural gas properties were recorded for the years ended December 31, 2022 and 2021.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. As of December 31, 2022 and 2021, the Company had no properties excluded from the full cost pool. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and natural gas liquids ("NGL") reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Other Property and Equipment, Net

Other property and equipment primarily consists of a gathering system, computer equipment and software, office furniture, and an office building for field operations. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from two to 39 years. Depreciation expense for other property and equipment was $0.7 million and $0.7 million for the years ended December 31, 2022 and 2021, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cashflows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment was recorded for the years ended December 31, 2022 or 2021.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production equipment not placed in service as of December 31, 2022 and 2021. The Company's equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units. The inventory is primarily acquired for use in future drilling or repair operations.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $0.7 million, net of accumulated amortization of $0.4 million as of December 31, 2022. As of December 31, 2021, other assets included costs related to the credit facility of $0.7 million, net of accumulated amortization of $0.3 million. These costs are being amortized over the term of the credit facility and are reported as interest expense on the Company's statements of operations.

Income Taxes

The Company is an LLC taxed as a partnership, and any associated tax liability is the responsibility of the individual members of the LLC. Accordingly, no provision for income taxes has been made in these financial statements.

The Company disallows the recognition of tax positions not deemed to meet a "more-likely-than not" threshold of being sustained by the applicable tax authority. The Company's policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company has not recognized any potential interest or penalties in its financial statements for the year ended December 31, 2022. The Company's tax years 2021, 2020, and 2019 remain open for examination by state authorities.

General and Administrative Costs

General and administrative expenses include cost recovery from joint interest owners. Per the terms of the joint operating agreements with working interest owners, the Company has the right to recover costs using an established contractual rate. Recoveries for the years ended December 31, 2022 and 2021 were $6.5 million and $6.3 million, respectively.

Other Income

Other income includes interest income, gain/loss on sale of equipment and other miscellaneous items. The year ended December 31, 2021 includes the derecognition of a $3.5 million liability previously classified as revenue payable. The revenue payable was initially recorded as part of the acquisitions that formed the Company

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

in 2019. Upon continued research, the Company determined the revenue payable acquired was not valid. As this determination was made after the measurement period for the acquisitions had passed, the Company accounted for this as a change in estimate and recognized the amount in the statement of operations.

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO as of December 31, 2022 and 2021 (in thousands):

	December 31, 2022	December 31, 2021
Asset retirement obligation at beginning of period	$ 16,469	$ 15,568
Liabilities assumed in acquisitions	1,159	—
Liabilities settled	(206)	(33)
Liabilities revised	38	—
Accretion expense	1,039	934
Asset retirement obligation at end of period	$ 18,499	$ 16,469

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 8. Derivative Contracts, for the Company's management of price volatility.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statements of operations.

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGLs are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statements of operations.

Gathering Revenue

The Company's gathering revenue is generated from a majority owned gathering system acquired in one of the Company's acquisitions. The Company charges a gathering rate per MMBtu transported through the gathering system. Gathering revenue and gathering operating expense are recorded net of the Company's ownership interest in the system.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company 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. Each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the period ended December 31, 2022, three purchasers each accounted for more than 10% of the Company's revenue: NextEra Energy Marketing, LLC (27.4%); ETC Field Services LLC (23.2%); and Wheeler Midstream LLC. (10.6%). For the period ended December 31, 2021, three purchasers each accounted for more than 10% of the Company's revenue: NextEra Energy Marketing, LLC (30.6%);

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

ETC Field Services LLC (25.6%); and Wheeler Midstream LLC. (12.4%). The Company's receivables as of December 31, 2022 and 2021 from oil and gas sales are concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

As of December 31, 2022 and 2021, the Company had one customer that represented approximately 63.0% and 56.0%, respectively, of our total joint interest receivables.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Years Ended December 31,	
	2022	2021
Revenues:		
Oil	$ 14,419	$ 10,258
Natural gas	39,904	21,283
NGL	15,786	12,560
Gross oil, natural gas, and NGL sales	70,109	44,101
Transportation, gathering and marketing	1,279	744
Net oil, natural gas, and NGL sales	$ 71,388	$ 44,845

Recent Accounting Pronouncements Adopted

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)". ASU 2016-02 establishes a right of use "ROU" model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. All leases create an asset and a liability for the lessee and therefore recognition of those lease assets and lease liabilities is required by ASU 2016-02. When measuring lease assets and liabilities, payments to be made in optional extension periods should be included if the lessee is reasonably certain to exercise the option. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 will not impact the accounting or financial presentation of our mineral leases.

In July 2018, the FASB issued Accounting Standards Update 2018-11, "Leases (Topic 842): Targeted Improvements", which included the option to implement the standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings, as opposed to the modified retrospective transition method required when ASU 2016-02 was issued. This guidance is effective for periods after December 15, 2021 and the Company implemented effective January 1, 2022. See Note 12. Leases, for further discussion.

Recent Accounting Pronouncements Issued But Not Yet Adopted

In June 2016, the FASB issued Accounting Standards Update 2016-13, "Financial Instrument-Credit Losses: Measurement of Credit Losses on Financial Instruments," which amends reporting guidance on credit loses for certain financial instruments. The Company's primary risk for credit losses related to its receivables from joint interest owners in our operated oil and natural gas wells. This guidance is effective for periods after December 15, 2022. The Company is currently implementing it with no significant changes expected to the financial statements as the Company has no history of credit losses.

3. Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below (in thousands):

	Year ended December 31,	
	2022	2021
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 800	$ 698
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ (61)	$ (69)
Right-of-use assets obtained in exchange for lease liabilities	$ 1,360	$ —

4. Acquisitions

2022 Acquisitions

On February 3, 2022, the Company executed a purchase and sale agreement with Ellipse Resources, LLC for the sale of certain oil and gas properties in Oklahoma for $16.2 million subject to certain adjustments. The transaction closed on March 24, 2022 and was effective as of October 1, 2021. The acquisition was funded through operational cash flow. The purchase was accounted for as an asset acquisition as substantially all the fair value of the acquired assets could be allocated to a single identifiable asset group. Acquired assets primarily consist of oil and gas properties of $12.0 million, net of asset retirement obligations assumed of $1.2 million. Cash paid for assets as of December 31, 2022 was $12.0 million.

5. Property and Equipment

The Company's property and equipment consists of the following (in thousands):

	December 31, 2022	December 31, 2021
Oil and natural gas properties		
Proved properties	$ 82,989	$ 68,948
Accumulated depreciation, depletion and impairment	(38,024)	(34,575)
Oil and natural gas properties, net	44,965	34,373
Other property and equipment		
Buildings and leasehold improvements	1,907	1,907
Office equipment	138	138
Vehicles	453	444
Land	320	320
Gathering system	8,600	8,600
Total other property and equipment	11,418	11,409
Accumulated depreciation, depletion and amortization	(2,102)	(1,435)
Total other property and equipment, net	$ 9,316	$ 9,974

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6. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	December 31, 2022	December 31, 2021
Lease operating expense	$ 1,998	$ 823
Capital expenditures	1	98
Payroll costs	895	662
General, administrative, and other	318	488
Total accrued liabilities	$ 3,212	$ 2,071

7. Long-Term Debt

The Company maintains a revolving credit facility ("the credit facility") with a syndicate of banks, including East West Bank, who serves as sole book runner and lead arranger, maturing in September 2024. Outstanding obligations under the credit facility are secured by substantially all of the Company's assets.

The credit agreement provides for a revolving credit facility in the maximum of $250.0 million, subject to a borrowing base of $26.0 million as of December 31, 2022. As of December 31, 2022, $17.1 million was outstanding under the credit facility. The amount available to be borrowed under the credit facility is subject to a borrowing base that is redetermined semiannually each April and October in an amount determined by the lenders. The Company's borrowing base was last affirmed at $26.0 million in conjunction with the October 2022 re-determination.

The Company entered into the fourth amendment to the credit agreement on December 8, 2022. The fourth amendment includes an excess cash threshold that sets a limit of the consolidated cash balance of the Company at $5.0 million. Excess cash will be swept only when the Company experiences an "anti-cash triggering event" defined as one or more of the following:

- Ratio of total debt to EBITDAX greater than 2.5 evaluated each fiscal quarter
- Liquidity is less than 20% of the borrowing base.
- An event of default or borrowing base deficiency occurs.

The consolidated cash balance is defined as the total unrestricted cash and cash equivalents held by the Company, less any cash set aside to pay royalty obligations, working interest obligations, suspense payments, severance taxes, payroll, payroll taxes, other taxes, employee wage and benefits.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. Financial ratios the Company is required to maintain on a quarterly basis include the ratio of total debt to EBITDAX not greater than 2.5 and the ratio of current assets to current liabilities of no less than 1.0. As of December 31, 2022 and 2021, the Company was in compliance with all applicable covenants under the credit facility.

Outstanding borrowings under the credit agreement bear interest at a per annum rate that is equal to the SOFR rate (which is equal to the Term SOFR rate as published by the Chicago Mercantile Exchange, Inc., CME Group Inc. and their affiliates or their successor as the administrator for Term SOFR two business days before commencement of such interest period, subject to SOFR adjustment periods one month: 0.10%, three months: 0.15%, and six months: 0.25%), plus the applicable margin. The applicable margin ranges from 1.25% to 2.25% in the case of the alternate base rate and from 2.25% to 3.25% in the case of SOFR, in each case depending on the amount of loans and letters of credit outstanding. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of December 31, 2022 was 7.27%.

8. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These transactions are in the form of fixed price swaps. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 9, Fair Value Measurements for additional information regarding fair value measurements.

The following table summarizes the open financial derivative positions as of December 31, 2022, related to gas production:

Period	Volume (Mmbtu)	Weighted Average Fixed Price
January – March 2023	726	$ 4.95

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The following table presents the gross amounts of recognized derivative assets, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	December 31, 2022	December 31, 2021
Derivative contracts – current, gross	$ 737	$ —
Netting arrangements	—	—
Derivative contracts – current, net	$ 737	$ —

The following table presents the gross amounts of recognized derivative liabilities, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	December 31, 2022	December 31, 2021
Derivative contracts – current, gross	$ —	$ 1,397
Netting arrangements	—	—
Derivative contracts – current, net	$ —	$ 1,397

Gains and Losses. The following table presents the settlement and mark-to-market (“MTM”) gains and losses presented as a gain or loss on derivatives in the statements of operations (in thousands):

	Years Ended December 31,	
	2022	2021
Settlements on derivatives	$ (5,669)	$ (2,916)
MTM gains (losses) on derivatives, net	2,134	(1,578)
Total losses on derivative contracts	$ (3,535)	$ (4,494)

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8. Derivative Contracts (cont.)

The following table presents the gains and losses recognized on oil and natural gas derivatives in the accompanying statements of operations (in thousands):

	Years Ended December 31,	
	2022	2021
Oil derivatives	$ (1,555)	$ (3,482)
Natural gas derivatives	(1,980)	(1,012)
Total losses on derivative contracts, net	$ (3,535)	$ (4,494)

9. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company’s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 — Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.

Level 3 — Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2022 and 2021 (in thousands):

	Level 1	Level 2	Level 3	Fair Value
As of December 31, 2021				
Liabilities:				
Derivative Instruments	$ —	$ 1,397	$ —	$ 1,397
As of December 31, 2022				
Assets:				
Derivative Instruments	$ —	$ 737	$ —	$ 737

9. Fair Value Measurements (cont.)

Fair Value on a Non-Recurring Basis

The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair values due to the short-term maturities of these instruments.

The carrying amount of the Company's credit facility approximates fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

10. Equity Compensation and Deferred Compensation Plan

As part of the Company's amended and restated LLC agreement as of March 25, 2021, incentive units (Class B Units) were issued to certain employees as compensation for services to be rendered to the Company. In determining the appropriate accounting treatment, the Company considered the characteristics of the awards in terms of treatment as stock-based compensation. US GAAP generally requires that all equity awards granted to employees be accounted for at fair value and recognized as compensation cost over the vesting period.

The incentive units are subject to graded vesting over a period of 3 or 4 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units forfeits unvested incentive units upon ceasing to be an employee of the Company, excluding limited exceptions. The Company recognizes forfeitures as they occur. Holders of incentive units participate in distributions upon the Company meeting a certain requisite financial internal rate of return threshold as defined in the amended and restated LLC agreement.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For awards granted for the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 62%
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 1.40%

On March 25, 2021, all 20,000 authorized incentive units were granted. Total non-cash compensation cost related to the incentive units was $0.7 million and $3.4 million for the years ended December 31, 2022 and 2021, respectively. As of December 31, 2022, there was $0.2 million in unrecognized compensation cost related to incentive units, which is expected to be recognized over a weighted-average period of 0.5 years.

10. Equity Compensation and Deferred Compensation Plan (cont.)

A summary of the incentive unit awards as of December 31, 2022 is as follows:

	Class B units	Weighted Average Grant Date Fair Value
Unvested at March 25, 2021	20,000	$ 213.39
Vested	(9,667)	$ 213.39
Unvested at December 31, 2021	10,333	$ 213.39
Vested	(3,665)	$ 213.39
Unvested at December 31, 2022	6,668	$ 213.39

As part of the Company's amended and restated LLC agreement as of March 25, 2021 and the Class A-2 Issuance Agreement, the Company issued 480 Class A-2 Units to an employee of Mach Resources LLC ("Mach Resources") for services performed for the Company. Additional Class A-2 Units were granted on a quarterly basis during the year ended December 31, 2021 to the employee and vested on the grant date. There were no new awards granted for the year ended December 31, 2022. In accordance with US GAAP, the equity awards granted to the employee will be accounted for at fair value and recognized as compensation cost over the vesting period.

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For awards granted for the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 62%
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 1.40%

There were no unvested Class A-2 Units and no related unrecognized costs as of December 31, 2022.

11. Commitments and Contingencies

Legal Matters. In the ordinary course of business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. The Company did not recognize any material liability as of December 31, 2022. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

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12. Leases

Effective January 1, 2022, the Company adopted ASU No. 2016-02, Leases (Topic 842). The new standard supersedes the previous lease guidance by requiring lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases. The Company adopted the new standard on a prospective basis using the simplified transition method permitted by ASU No. 2018-11, Leases (Topic 842): Targeted Improvements. No cumulative-effect adjustment to retained earnings was required upon adoption of the new standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. The Company elected the package of practical expedients permitted under the new standard, which among other things, allows for lease and non-lease components in a contract to be accounted for as a single lease component for all asset classes and the carry forward of historical lease classifications.

Nature of Leases

The Company has operating leases on vehicles with remaining lease durations in excess of one year. These leases have various expiration dates throughout 2026. The vehicles are used for field operations and leased from third parties. The Company recognizes right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses the U.S. 5 Year Treasury Rate in determining the present value of lease payments. Minor changes to the discount rate do not have a material impact to the calculation of the liability, therefore the Company will use this for all asset classes.

Future amounts due under operating lease liabilities as of December 31, 2022, were as follows (in thousands):

2023	$	390
2024		352
2025		330
2026		143
Total lease payments	$	1,215
Less: imputed interest		(102)
Total	$	1,113

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the year ended December 31, 2022 (in thousands):

Operating lease cost	$	251
Short-term lease cost		2,954
Total lease cost	$	3,205

The weighted-average remaining lease term as of December 31, 2022 was 3.3 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2022 was 3.93%.

13. Members' Equity

Upon formation, the Company consisted of one class of common interests that were all owned by its initial member, BCE-Mach Holdings II. On March 25, 2021, per the amended and restated LLC agreement and the Class A-2 Issuance Agreement, the Company issued 76,500 Class A-1 Units to the initial member, and 480 Class A-2 Units to an employee of Mach Resources for services performed for the Company. Additionally, Class A-2 Units were granted to the employee on a quarterly basis throughout 2021. In 2022, the Class A-2 Issuance Agreement was updated and there are no additional units being granted to the employee. As of December 31, 2022, there were 788 total Class A-2 Units issued to the employee, which have substantially all the same rights as the

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13. Members' Equity (cont.)

initial member. As part of a long-term incentive plan for certain employees, 20,000 Class B Units were outstanding as of December 31, 2022. The Class B Units represent a non-voting interest in the Company that allows the holder to participate in distributions once the Company's Class A shares have met a certain requisite financial internal rate of return in accordance with the LLC agreement.

Distributions to the members for the years ended December 31, 2022 and 2021 were $37.4 million and $6.0 million, respectively. There were no contributions from the members for the years ended December 31, 2022 or 2021.

14. Related Parties

Management Services Agreement. Upon formation of the Company, the Company entered into a management services agreement ("MSA") with Mach Resources. Under the MSA, Mach Resources manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company distributes funding to Mach Resources for performance under the MSA. During the years ended December 31, 2022 and 2021, the Company paid Mach Resources $9.9 million and $7.6 million, respectively. As of December 31, 2022 and 2021, the Company had $0.2 million and $0.3 million in prepaid assets with Mach Resources, respectively.

BCE-Mach LLC and BCE-Mach III LLC. BCE-Mach LLC and BCE-Mach III LLC are two related parties that also entered into a MSA with Mach Resources. These entities have shared ownership with the Company and operate primarily in different geographical locations than the Company. As of December 31, 2022 the Company has receivables from these related parties for approximately $0.5 million. As of December 31, 2021 the Company had receivables from these related parties for approximately $1.0 million.

15. Subsequent Events

The Company has evaluated its financial statements for subsequent events through March31, 2023, the date the financial statements were available to be issued to ensure that any subsequent events that met the criteria for recognition and disclosure in this report have been properly included.

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

The following tables provide historical cost information regarding the Company's oil and gas operations located entirely in the United States:

Capitalized Costs related to Oil and Gas Producing Activities

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Proved properties	$ 82,989	$ 68,948
Accumulated depreciation, depletion, amortization and impairment	(38,024)	(34,575)
Net capitalized costs	$ 44,965	$ 34,373

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Acquisition	$ 12,028	$ —
Development	1,021	930
Exploratory	—	—
Costs incurred	$ 13,049	$ 930

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

Results of Operations for Producing Activities

The following table includes revenue and expenses related to the production and sale of oil, natural gas, and NGLs. It does not include any derivative activity, interest costs or general and administrative costs.

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Revenues	$ 71,388	$ 44,845
Production costs	(23,810)	(16,815)
Depreciation, depletion, amortization and accretion	(4,487)	(4,284)
Results of operations from producing activities	$ 43,091	$ 23,746

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. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved undeveloped reserves or PUDs. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the US GAAP. 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.

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 2).

The standardized measure does not represent management's estimate of our future cash flows or the fair 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 affected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

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

Proved Reserves Summary

All of the Company's reserves are located in the United States. The following table sets forth the changes in the Company's net proved reserves (including developed and undeveloped reserves) for the years ended December 31, 2022 and 2021. Reserves estimates as of December 31, 2022 were estimated by the independent petroleum consulting firm Cawley, Gillespie & Associates, Inc.

Proved Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	1.2	52.7	3.6	13.5
Revisions of previous estimates	0.6	40.7	2.4	9.8
Purchases in place	—	—	—	—
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	(0.2)	—	—
Production	(0.2)	(7.0)	(0.5)	(1.8)
December 31, 2021	1.6	86.2	5.5	21.5
Revisions of previous estimates	0.2	14.7	1.7	4.3
Purchases in place	—	5.6	—	1.0
Extensions, discoveries and other additions	—	—	—	—
Sales in place	—	—	—	—
Production	(0.1)	(7.6)	(0.5)	(1.9)
December 31, 2022	1.7	98.9	6.7	24.9

Proved Developed Reserves	**Oil (mmbbl)**	**Natural Gas (bcf)**	**NGL (mmbbl)**	**Oil Equivalents (mmboe)**
December 31, 2020	1.2	52.7	3.6	13.5
December 31, 2021	1.6	86.2	5.5	21.5
December 31, 2022	1.7	98.9	6.7	24.9

In 2021, the 9.8 mmboe of upward revisions in proved reserves were the result of a combination of higher commodity prices (6.1 mmboe), upward proved developed producing production forecasts (2.5 mmboe) and revisions in lease operating expenses and product price differentials to reflect current market conditions (1.2 mmboe).

In 2022, the 1.0 mmboe of acquisitions represents the reserves acquired from Ellipse Resources in February 2022 (note 4). The 4.3 mmboe of upward revisions in proved reserves were the result of higher commodity prices (2.4 mmboe) and revisions to lease operating expenses and product price differentials to reflect current market conditions (1.9 mmboe).

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

The following table sets forth the standardized measure of discounted future net cash flow from projected production of the Company's oil and natural gas reserves:

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves (in thousands)	**December 31, 2022**	**December 31, 2021**
Future cash inflows	$ 852,310	$ 446,106
Future costs:		
Production[(1)]	(292,974)	(173,520)
Development[(2)]	(23,486)	(21,487)
Income taxes	—	—
Future net cash flows	535,850	251,099
10% annual discount	(281,020)	(126,914)
Standardized measure	$ 254,830	$ 124,185

(1) Production costs include production severance taxes, ad valorem taxes and operating expenses.
(2) Development costs include plugging expenses, net of salvage and net capital investment.

Changes in Standardized Measure of Discounted Future Net Cash Flows (in thousands)	**For the Year Ended December 31, 2022**	**2021**
Standardized measure, beginning of period	$ 124,185	$ 29,940
Extensions, discoveries and improved recovery less related costs	—	—
Revisions of previous quantity estimates	45,324	61,615
Changes in estimated future development costs	210	255
Purchases (sales) of minerals in place	9,699	—
Net changes in prices and production costs	100,586	57,409
Accretion of discount	12,418	2,994
Sales of oil and gas produced, net of production costs	(47,578)	(28,030)
Development costs incurred during the period	441	516
Change in timing of estimated future production and other	9,545	(514)
Net change in income taxes	—	—
Standardized measure, end of period	$ 254,830	$ 124,185

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

Average oil prices used in the estimation of proved reserves and calculation of the standardized measure were $93.67 for 2022 and $66.56 for 2021. Average realized gas prices were $6.36 for 2022 and $3.60 for 2021. We used 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period.

BCE-Mach II LLC Unaudited Financial Statements

As of June 30, 2023 and December 31, 2022 and for the six months ended June 30, 2023 and 2022

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BCE-MACH II LLC
BALANCE SHEETS (UNAUDITED)
(in thousands)

	June 30, 2023	December 31, 2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 11,321	$ 19,303
Accounts receivable – joint interest and other	6,823	9,586
Accounts receivable – oil, gas, and NGL sales	1,548	10,326
Short-term derivative contracts	429	737
Inventories	1,085	1,154
Other current assets	690	1,449
Total current assets	21,896	42,555
Oil and natural gas properties, using the full cost method:		
Proved oil and natural gas properties	81,280	82,989
Less: accumulated depreciation, depletion, and impairment	(39,651)	(38,024)
Oil and natural gas properties, net	41,629	44,965
Other property, plant and equipment	11,474	11,418
Less: accumulated depreciation	(2,448)	(2,102)
Other property, plant and equipment, net	9,026	9,316
Other assets	169	235
Operating lease assets	1,145	1,113
Total assets	$ 73,865	$ 98,184
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 1,222	$ 1,940
Accrued liabilities	2,657	3,212
Revenue payable	15,839	22,952
Current portion of operating lease liabilities	426	374
Total current liabilities	20,144	28,478
Long-term debt	17,100	17,100
Asset retirement obligations	19,028	18,499
Other long-term liabilities	482	524
Long-term portion of operating lease liabilities	720	739
Total long-term liabilities	37,330	36,862
Commitments and contingencies (Note 10)		
Members' equity	16,391	32,844
Total liabilities and members' equity	$ 73,865	$ 98,184

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
STATEMENT OF OPERATIONS (UNAUDITED)
(in thousands)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
Revenue		
Oil, natural gas, and NGL sales	$ 16,363	$ 34,878
Gain (loss) on oil and natural gas derivatives, net	828	(1,679)
Gathering revenue	213	245
Total revenues	17,404	33,444
Operating expenses		
Gathering and processing	1,992	2,770
Gathering operating expense	223	217
Lease operating expense	6,310	6,155
Production taxes	833	1,966
Depreciation, depletion, and accretion – oil and natural gas	2,167	2,211
Depreciation and amortization – other	346	341
General and administrative	(1,536)	(1,349)
Total operating expenses	10,335	12,311
Income from operations	7,069	21,133
Other (expense) income		
Interest expense	(747)	(374)
Other (expense) income, net	(646)	12
Total other expense	(1,393)	(362)
Net income	$ 5,676	$ 20,771

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
STATEMENTS OF MEMBERS' EQUITY (UNAUDITED)
(in thousands)

	Total Members' Equity
Balance at December 31, 2022	$ 32,844
Net income	5,676
Equity compensation	116
Distributions	(22,245)
Balance at June 30, 2023	$ 16,391
Balance at December 31, 2021	$ 29,082
Net income	20,770
Equity compensation	338
Distributions	(12,000)
Balance at June 30, 2022	$ 38,190

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	Six Months Ended June 30,	
	2023	**2022**
Cash flows from operating activities		
Net income	$ 5,676	$ 20,771
Adjustments to reconcile net income to cash provided by operating activities		
Depreciation and depletion	2,513	2,552
(Gain) loss on derivative instruments	(828)	1,679
Cash receipts on settlement of derivative contracts, net	1,060	(1,360)
Debt issuance costs amortization	67	66
Equity based compensation	116	338
Credit losses	767	—
Settlement of asset retirement obligations	(2)	(39)
Changes in operating assets and liabilities (decreasing) increasing cash:		
Accounts receivable, inventories, other assets	11,585	(7,267)
Revenue payable	(7,113)	6,713
Accounts payable and accrued liabilities	(1,221)	128
Net cash provided by operating activities	12,620	23,581
Cash flows from investing activities		
Capital expenditures for oil and natural gas properties	(291)	(247)
Capital expenditures for other property and equipment	(56)	—
Acquisition of assets	—	(13,654)
Divestiture of assets	1,990	—
Net cash provided by (used) in investing activities	1,643	(13,901)
Cash flows from financing activities		
Repayments of borrowings	—	(4,500)
Distributions to members	(22,245)	(12,000)
Net cash used in financing activities	(22,245)	(16,500)
Net decrease in cash and cash equivalents	(7,982)	(6,820)
Cash and cash equivalents, beginning of period	19,303	29,588
Cash and cash equivalents, end of period	$ 11,321	$ 22,768

The accompanying notes are an integral part of these financial statements.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

1. Nature of Business

BCE-Mach II LLC ("the Company") was formed on October 26, 2018, as a limited liability company under the laws of the State of Delaware. On July 9, 2019, the Company entered into the original LLC agreement with its initial member. An employee was admitted as a member of the Company in the LLC agreement as amended and restated on March 25, 2021. On September 13, 2019, and September 27, 2019, the Company closed on two acquisitions and operations subsequently began. The Company owns and operates producing wells and undeveloped acreage primarily in the Anadarko Basin in both Texas and Oklahoma.

2. Basis of presentation and Summary of Significant Accounting Policies

Basis of Presentation

The unaudited financial statements included herein were prepared fromrecords of the Company in accordance with generally accepted accounting principles in the United States ("US GAAP"). These financial statements should be read in conjunction with the audited financial statements and notes thereto for the year ended December 31, 2022. Results for interim periods are not necessarily indicative of results to be expected for the full year ending December 31, 2023. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the financial information, have been included.

Use of Estimates

The preparation of the financial statements in conformity with US GAAP 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. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the fair value determination of acquired assets and liabilities, equity based compensation, and the fair value estimates of commodity derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the financial statements. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk in this area.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for credit losses when the Company believes collection is doubtful. The Company extends credit to joint interest owners and generally does not require collateral. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for credit losses. The company recorded credit losses of $0.8 million during the six months ended June 30, 2023, which is presented as other expense in the Statement of Operations. The company did not record any credit losses during the six months ended June 30, 2022. At June 30, 2023 and December 31, 2022, the Company's allowance for credit losses was not material.

Derivative Instruments

The Company is required to recognize its derivative instruments on the balance sheet as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments for each period in the statements of operations.

Oil and Natural Gas Operations

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities, which are expensed as incurred. Capitalized costs are depreciated using the unit-of production method. Under this method, depletion is computed at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by a net equivalent proved reserves at the beginning of the period. The average depletion rate per barrel equivalent unit of production was $1.87 for the six months ended June 30, 2023, respectively. The average depletion rate per barrel equivalent unit of production was $1.84 for the six months ended June 30, 2022, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $1.6 million for the six months ended June 30, 2023, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $1.7 million for the six months ended June 30, 2022, respectively.

Under the full cost method, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the full cost "ceiling" at the end of each quarter. The ceiling is calculated based on the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%. The estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Estimated future net cash flows are calculated using the preceding 12-months' average price based on closing prices on the first day of each month. The net book value is compared to the ceiling limitation on an annual basis. The excess, if any, of the net book value above the ceiling limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. The ceiling limitation computation is determined without regard to income taxes due to the Internal Revenue Service ("IRS") recognition of the Company as a flow-through entity. No impairments on proved oil and natural gas properties were recorded for the six months ended June 30, 2023 and 2022.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. As of June 30, 2023, and December 31, 2022, the Company had no properties excluded from the full cost

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

pool. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Sales of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and natural gas liquids ("NGL") reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Other Property and Equipment, Net

Other property and equipment primarily consists of a gathering system, computer equipment and software, office furniture, and an office building for field operations. Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 2 to 39 years. Depreciation expense for other property and equipment was $0.3 million for the six months ended June 30, 2023, respectively. Depreciation expense for other property and equipment was $0.3 million for the six months ended June 30, 2022, respectively.

Impairment losses are recorded on property and equipment used in operations and other long-lived assets held and used when indicators of impairment are present and the undiscounted cashflows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. No impairment of other property and equipment was recorded for the six months ended June 30, 2023, or 2022.

Inventories

Inventories are stated at the lower of cost or net realizable value and consist of production equipment not placed in service as of June 30, 2023 and December 31, 2022. The Company's equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units. The inventory is primarily acquired for use in future drilling or repair operations.

Debt Issuance Costs

Other assets include capitalized costs related to the credit facility of $0.7 million, net of accumulated amortization of $0.5 million as of June 30, 2023. As of December 31, 2022, other assets included costs related to the credit facility of $0.7 million, net of accumulated amortization of $0.4 million. These costs are being amortized over the term of the credit facility and are reported as interest expense on the Company's statements of operations.

Income Taxes

The Company is an LLC taxed as a partnership, and any associated tax liability is the responsibility of the individual members of the LLC. Accordingly, no provision for income taxes has been made in these financial statements.

The Company disallows the recognition of tax positions not deemed to meet a "more-likely-than not" threshold of being sustained by the applicable tax authority. The Company's policy is to reflect interest and penalties related to uncertain tax positions in general and administrative expense, when and if they become applicable. The Company has not recognized any potential interest or penalties in its financial statements for the six months ended June 30, 2023, and 2022. The Company's tax years 2022, 2021, 2020, and 2019 remain open for examination by state authorities.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

General and Administrative Costs

General and administrative expenses include cost recovery from joint interest owners. Per the terms of the joint operating agreements with working interest owners, the Company has the right to recover costs using an established contractual rate. Recoveries for the six months ended June 30, 2023, and 2022 were $3.3 million and $3.3 million, respectively.

Asset Retirement Obligations

The Company records the fair value of the future legal liability for an asset retirement obligation ("ARO") in the period in which the liability is incurred (at the time the wells are drilled or acquired), with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is satisfied.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future downhole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of a field's surface to a condition similar to that existing before oil and natural gas extraction began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes materially, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The following is a reconciliation of ARO for the six months ended (in thousands):

	June 30, 2023	June 30, 2022
Asset retirement obligation at beginning of period	$ 18,499	$ 16,469
Liabilities incurred	4	—
Liabilities assumed in acquisitions	—	533
Liabilities settled	(7)	(104)
Liabilities revised	(9)	(4)
Accretion expense	541	501
Asset retirement obligation at end of period	$ 19,028	$ 17,395

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The Company's performance obligations are satisfied at a point in time. This occurs when control is transferred to the purchaser upon delivery of contract specified production volumes at a specified point. The pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with other available oil, natural gas and NGL supplies.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

several years, and the Company expects this volatility to continue in the future. The prices the Company receives for production depend on many factors outside of our control. See Note 8. Derivative Contracts, for the Company's management of price volatility.

Oil Sales

The Company's oil sales contracts are structured where it delivers oil to the purchasers at the wellhead, where the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company's statements of operations.

Natural Gas and NGL Sales

Under the Company's natural gas and NGL sales contracts, it first delivers wet natural gas to a midstream processing entity. After processing, the residue gas is transported to the purchaser at the inlet to certain natural gas pipelines, where the purchaser takes control, title and risk of loss of the product. The NGLs are delivered to the purchaser at the tailgate of the midstream processing plant, where the purchaser takes control, title and risk of loss of the product. For both natural gas sales and NGL sales, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with gathering and processing fees presented as an expense in its statements of operations.

Gathering Revenue

The Company's gathering revenue is generated from a majority owned gathering system acquired in one of the Company's acquisitions. The Company charges a gathering rate per MMBtu transported through the gathering system. Gathering revenue and gathering operating expense are recorded net of the Company's ownership interest in the system.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that are short-term in nature with a contract term of one year or less, the Company has utilized the practical expedient that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient, which states that a company 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. Each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered and control passes to the customer. However, settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company records variances between its estimates and actual amounts received in the month payment is received and such variances have historically not been significant.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

2. Basis of presentation and Summary of Significant Accounting Policies (cont.)

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the six months ended June 30, 2023, four purchasers each accounted for more than 10% of the Company's revenue: ETC Field Services LLC (20.2%); NextEra Energy Marketing, LLC (16.0%); Wheeler Midstream LLC (13.7%); and Enbridge Inc. (10.2%). For the six months ended June 30, 2022, three purchasers each accounted for more than 10% of the Company's revenue: ETC Field Services LLC (25.1%); NextEra Energy Marketing, LLC (17.4%); and Wheeler Midstream LLC (11.4%). The Company's receivables as of June 30, 2023, and December 31, 2022, from oil and gas sales are concentrated with the same counterparties noted above. The Company does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

As of June 30, 2023, and December 31, 2022, the Company had one customer that represented approximately 49.7% and 63.0%, respectively, of our total joint interest receivables.

Revenue Disaggregation

The following table displays the revenue disaggregated and reconciles disaggregated revenue to the revenue reported (in thousands):

	Six months ended	
	June 30, 2023	June 30, 2022
Revenues:		
Oil	$ 5,302	$ 7,540
Natural gas	6,867	17,808
NGL	3,966	8,855
Gross oil, natural gas, and NGL sales	16,135	34,203
Transportation, gathering and marketing	228	675
Net oil, natural gas, and NGL sales	$ 16,363	$ 34,878

Recent Accounting Pronouncements Adopted

In June 2016, the FASB issued Accounting Standards Update 2016-13, "Financial Instrument-Credit Losses: Measurement of Credit Losses on Financial Instruments," which amends reporting guidance on credit loses for certain financial instruments. The Company's primary risk for credit losses related to its receivables from joint interest owners in our operated oil and natural gas wells. This guidance is effective for periods after December 15, 2022, and the Company implemented it effective January 1, 2023, with no material impacts to the financial statements.

3. Supplemental Cash Flow Information

Supplemental disclosures to the statements of cash flows are presented below (in thousands):

	Six months ended June,	
	2023	2022
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 683	$ 309
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ —	$ (15)
Right-of-use assets obtained in exchange for lease liabilities	$ 187	$ 491

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

4. Property and Equipment

The Company's property and equipment consists of the following (in thousands):

	June 30, 2023	December 31, 2022
Oil and natural gas properties		
Proved properties	$ 81,280	$ 82,989
Accumulated depreciation, depletion and impairment	(39,651)	(38,024)
Oil and natural gas properties, net	41,629	44,965
Other property and equipment		
Buildings and leasehold improvements	1,918	1,907
Office equipment	139	138
Vehicles	497	453
Land	320	320
Gathering system	8,600	8,600
Total other property and equipment	11,474	11,418
Accumulated depreciation, depletion and amortization	(2,448)	(2,102)
Total other property and equipment, net	$ 9,026	$ 9,316

5. Accrued Liabilities

Accrued liabilities consist of the following (in thousands):

	June 30, 2023	December 31, 2022
Lease operating expense	$ 1,171	$ 1,998
Capital expenditures	—	1
Payroll costs	1,017	895
General, administrative, and other	469	318
Total accrued liabilities	$ 2,657	$ 3,212

6. Long-Term Debt

The Company maintains a revolving credit facility ("the Credit Facility") with a syndicate of banks, including East West Bank, who serves as sole book runner and lead arranger, maturing in September 2024. Outstanding obligations under the Credit Facility are secured by substantially all of the Company's assets.

The credit agreement provides for a revolving Credit Facility in the maximum of $250.0 million, subject to a borrowing base of $26.0 million as of June 30, 2023. As of June 30, 2023, $17.1 million was outstanding under the Credit Facility. The amount available to be borrowed under the Credit Facility is subject to a borrowing base that is redetermined semiannually each April and October in an amount determined by the lenders. The Company's borrowing base was last affirmed at $26.0 million in conjunction with the April 2023 re-determination.

The Company entered into the fourth amendment to the credit agreement on December 8, 2022. The fourth amendment includes an excess cash threshold that sets a limit of the consolidated cash balance of the Company at $5.0 million. Excess cash will be swept only when the Company experiences an "anti-cash triggering event" defined as one or more of the following:

- Ratio of total debt to EBITDAX greater than 2.5 evaluated each fiscal quarter
- Liquidity is less than 20% of the borrowing base.
- An event of default or borrowing base deficiency occurs.

6. Long-Term Debt (cont.)

The consolidated cash balance is defined as the total unrestricted cash and cash equivalents held by the Company, less any cash set aside to pay royalty obligations, working interest obligations, suspense payments, severance taxes, payroll, payroll taxes, other taxes, employee wage and benefits.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios. Financial ratios the Company is required to maintain on a quarterly basis include the ratio of total debt to EBITDAX not greater than 2.5 and the ratio of current assets to current liabilities of no less than 1.0. As of June 30, 2023, and December 31, 2022, the Company was in compliance with all applicable covenants under the credit facility.

Outstanding borrowings under the credit agreement bear interest at a per annum rate that is equal to the SOFR rate (which is equal to the Term SOFR rate as published by the Chicago Mercantile Exchange, Inc., CME Group Inc. and their Affiliates or their successor as the administrator for Term SOFR two Business Days before commencement of such Interest Period, subject to SOFR adjustment periods one month: 0.10%, three months: 0.15%, and six months: 0.25%), plus the applicable margin. The applicable margin ranges from 1.25% to 2.25% in the case of the alternate base rate and from 2.25% to 3.25% in the case of SOFR, in each case depending on the amount of loans and letters of credit outstanding. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding. The effective interest rate as of June 30, 2023, and December 31, 2022, was 8.3% and 7.3%, respectively.

7. Derivative Contracts

The Company uses derivative contracts to reduce exposure to fluctuations in commodity prices. These transactions are in the form of fixed price swaps. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. The Company does not intend to hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Under fixed price swap contracts, the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

The Company reports the fair value of derivatives on the balance sheet in derivative contracts assets and derivative contracts liabilities as either current or noncurrent based on the timing of expected future cash flows of individual trades. See Note 8, Fair Value Measurements for additional information regarding fair value measurements.

As of June 30, 2023, the Company effectively has no oil or gas volumes hedged due to offsetting swap positions of equal volumes.

7. Derivative Contracts (cont.)

Balance Sheet Presentation. The Company has master netting agreements with all of its derivative counterparties and presents its derivative assets and liabilities with the same counterparty on a net basis on the balance sheet. The following table presents the gross amounts of recognized derivative assets, the amounts that are subject to offsetting under master netting arrangements and the net recorded fair values as recognized on the balance sheet (in thousands):

	June 30, 2023	December 31, 2022
Derivative contracts – current, gross	$ 429	$ 737
Netting arrangements	—	—
Derivative contracts – current assets, net	$ 429	$ 737

Gains and Losses. The following table presents the settlement and mark-to-market ("MTM") gains and losses presented as a gain or loss on derivatives in the statements of operations (in thousands):

	Six months ended June 30,	
	2023	2022
Settlements on derivatives	$ 1,135	$ (1,646)
MTM gains (losses) on derivatives, net	(307)	(33)
Total gains (losses) on derivative contracts	$ 828	$ (1,679)

The following table presents the gains and losses recognized on oil and natural gas derivatives in the accompanying statements of operations (in thousands):

	Six months ended	
	June 30, 2023	June 30, 2022
Oil derivatives	$ 295	$ (1,766)
Natural gas derivatives	533	87
Total gains (losses) on derivative contracts, net	$ 828	$ (1,679)

8. Fair Value Measurements

Fair value measurement is established by a hierarchy of inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 — Quoted prices are available in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2 — Quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets.

Level 3 — Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

8. Fair Value Measurements (cont.)

Fair Value on a Recurring Basis

Derivative Contracts. The Company determines the fair value of its derivative contracts using industry standard models that consider various assumptions including current market and contractual prices for the underlying instruments, time value, and nonperformance risk. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract and can be supported by observable data.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2023 and December 31, 2022 (in thousands):

	Level 1	Level 2	Level 3	Fair Value
As of June 30, 2023				
Assets:				
Derivative Instruments	$ —	$ 429	$ —	$ 429
As of December 31, 2022				
Assets:				
Derivative Instruments	$ —	$ 737	$ —	$ 737

Fair Value on a Non-Recurring Basis

The Company determines the initial estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted with proved oil and natural gas properties using the unit of production method.

Fair Value of Other Financial Instruments

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, revenue payable, accrued interest payable, and other current liabilities approximate fair values due to the short-term maturities of these instruments.

The carrying amount of the Company's credit facility approximates fair value, as the current borrowing base rate does not materially differ from market rates of similar borrowings.

9. Equity Compensation and Deferred Compensation Plan

As part of the Company's Amended and Restated LLC Agreement as of March 25, 2021, incentive units (Class B Units) were issued to certain employees as compensation for services to be rendered to the Company. In determining the appropriate accounting treatment, the Company considered the characteristics of the awards in terms of treatment as stock-based compensation. US GAAP generally requires that all equity awards granted to employees be accounted for at fair value and recognized as compensation cost over the vesting period.

The incentive units are subject to graded vesting over a period of 3 or 4 years (subject to accelerated vesting, as defined by the incentive unit agreement) and a holder of incentive units forfeits unvested incentive units upon ceasing to be an employee of the Company, excluding limited exceptions. The Company recognizes forfeitures as they occur. Holders of incentive units participate in distributions upon the Company meeting a certain requisite financial internal rate of return threshold as defined in the amended LLC agreement.

9. Equity Compensation and Deferred Compensation Plan (cont.)

Determination of the fair value of the awards requires judgements and estimates regarding, among other things, the appropriate methodologies to follow in valuing the award and the related inputs required by those valuation methodologies. For awards granted for the year ended December 31, 2021, the fair value underlying the compensation expense was estimated using the Black-Scholes valuation model with the following primary assumptions:

- expected volatility based on the historical volatilities of similar sized companies that most closely represent the Company's business of 62%
- 7 year expected term determined by management based on experience with similarly organized company and expectation of a future sale of the business
- a risk-free rate based on a U.S Treasury yield curve of 1.40%

On March 25, 2021, all 20,000 authorized incentive units were granted. Total non-cash compensation cost related to the incentive units was $0.1 million and $0.3 million for the six months ended June 30, 2023, and 2022, respectively. As of June 30, 2023, there was $0.1 million in unrecognized compensation cost related to incentive units, which is expected to be recognized over a weighted-average period of 0.5 years.

A summary of the incentive unit awards as of June 30, 2023, and 2022 is as follows:

	Class B units	Weighted Average Grant Date Fair Value
Unvested at December 31, 2021	10,333	$ 213.39
Vested	(3,665)	$ 213.39
Unvested at June 30, 2022	6,668	$ 213.39
Unvested at December 31, 2022	6,668	$ 213.39
Vested	(3,667)	$ 213.39
Unvested at June 30, 2023	3,001	$ 213.39

10. Commitments and Contingencies

Legal Matters. In the ordinary course of business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters. The Company did not recognize any material liability as of June 30, 2023. Management does not expect that the impact of such matters will have a materially adverse effect on the Company's financial position, results of operations or cash flows.

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

11. Leases

Nature of Leases

The Company has operating leases on an office space and vehicles with remaining lease durations in excess of one year. These leases have various expiration dates throughout 2026. The vehicles are used for field operations and leased from third parties. The Company recognizes right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses the U.S. 5 Year Treasury Rate in determining the present value of lease payments. Minor changes to the discount rate do not have a material impact to the calculation of the liability, therefore the Company will use this for all asset classes.

Future amounts due under operating lease liabilities as of June 30, 2023, were as follows (in thousands):

Remaining 2023	$	233
2024		436
2025		395
2026		143
Total lease payments	$	1,207
Less: imputed interest		(62)
Total	$	1,145

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the six months ended June 30, 2023, and 2022 (in thousands):

	Six months ended June 30,			
	2023		2022	
Operating lease cost	$	235	$	46
Short-term lease cost		1,386		1,462
Total lease cost	$	1,621	$	1,508

The weighted-average remaining lease term as of June 30, 2023, was 2.8 years. The weighted-average discount rate used to determine the operating lease liability as of June 30, 2023, was 3.9%.

12. Members' Equity

Upon formation, the Company consisted of one class of common interests that were all owned by its initial member, BCE-Mach Holdings II. On March 25, 2021, per the Amended and Restated LLC Agreement and the Class A-2 Issuance Agreement, the Company issued 76,500 Class A-1 Units to the initial member, and 480 Class A-2 Units to an employee of MR for services performed for the Company. Additionally, Class A-2 Units were granted to the employee on a quarterly basis throughout 2021. In 2022, the Class A-2 Issuance Agreement was updated and there are no additional units being granted to the employee. As of June 30, 2023, there were 788 total Class A-2 Units issued to the employee, which have substantially all the same rights as the initial member. As part of a long-term incentive plan for certain employees, 20,000 Class B Units were outstanding as of June 30, 2023. The Class B Units represent a non-voting interest in the Company that allows the holder to participate in distributions once the Company's Class A shares have met a certain requisite financial internal rate of return in accordance with the LLC agreement.

Distributions to the members for the six months ended June 30, 2023, and 2022 were $22.2 million and $12.0 million, respectively. There were no contributions from the members for the six months ended June 30, 2023, or 2022.

BCE-MACH II LLC
NOTES TO FINANCIAL STATEMENTS (UNAUDITED)

13. Related Parties

Management Services Agreement. Upon formation of the Company, the Company entered into a management services agreement ("MSA") with Mach Resources LLC ("MR"). Under the MSA, MR manages and performs all aspects of oil and gas operations and other general and administrative functions for the Company. On a monthly basis, the Company distributes funding to MR for performance under the MSA. During the six months ended June 30, 2023, the Company paid MR $5.7 million, which was inclusive of $0.2 million in management fees. During the six months ended June 30, 2022, the Company paid MR $5.0 million, which was inclusive of $0.1 million in management fees. As of June 30, 2023, and December 31, 2022, the Company had $0.3 million and $0.2 million in prepaid assets with MR, respectively.

BCE-Mach LLC and BCE-Mach III LLC. BCE-Mach LLC and BCE-Mach III LLC are two related parties that also entered into a MSA with Mach Resources. These entities have shared ownership with the Company and operate primarily in different geographical locations than the Company. As of June 30, 2023, the Company has receivables from these related parties for approximately $1.0 million included in accounts receivable-joint interest and other and $0.1 million included in accounts payable. As of December 31, 2022, the Company had receivables from these related parties for approximately $0.5 million included in accounts receivable-joint interest and other.

14. Subsequent Events

The Company has evaluated its financial statements for subsequent events through August30, 2023 the date the financial statements were available to be issued to ensure that any subsequent events that met the criteria for recognition and disclosure in this report have been properly included.

APPENDIX A

AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF MACH NATURAL RESOURCES LP

[To be filed by amendment]

APPENDIX B

GLOSSARY OF OIL AND GAS TERMS AND OTHER TERMS

The terms and abbreviations defined in this section are used throughout this prospectus:

"***Adjusted EBITDA***." Net income before (1) interest expense, (2) depreciation, depletion, amortization and accretion expense, (3) non-cash changes in derivative fair values, (4) equity-based compensation expense, (5) loss on contingent consideration and (6) gain on sale of assets.

"***Basin***." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"***Bbl***." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGL.

"***Bcf***." Billion cubic feet.

"***BCE***" or "***Sponsor***." Bayou City Energy, L.P. and affiliates thereof.

"***BCE-Mach***." BCE-Mach LLC, a Delaware limited liability company.

"***BCE-Mach II***." BCE-Mach II LLC, a Delaware limited liability company.

"***BCE-Mach III***" or "***predecessor***." BCE-Mach III LLC, a Delaware limited liability company.

"***BCE-Mach Aggregator***." BCE-Mach Aggregator LLC, a Delaware limited liability company.

"***BCE-Stack***." BCE-Stack Development LLC, a Delaware limited liability company.

"***Boe***." One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to one Bbl of oil.

"***British Thermal Unit***" or "***Btu***." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"***BWPD***." Barrels of water per day.

"***Cash operating costs***." Lease operating expenses, gas processing and transportation expense, production taxes, cash selling, general and administrative expense, midstream (benefit) and expense, marketing (benefit) and expense and other expenses.

"***Code***." Internal Revenue Code of 1986, as amended.

"***Completion***." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"***Developed acreage***." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"***Developed oil and gas reserves***." Developed oil and gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the related equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"***Development well***." A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"***Dry hole***." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"***Existing Credit Facilities***." The reserve-based revolving credit facilities of the Mach Companies which will be retired and replaced with the New Credit Facility of the Company upon consummation of this offering and the Reorganization Transactions.

"***Existing Owners***." Collectively refers to BCE and the Management Members.

"***Exploratory well***." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined under Regulation S-X.

"***Extension well***." A well drilled to extend the limits of a known reservoir.

"***Field***." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).

"***Focus Drilling Area***." Kingfisher and Logan Counties, Oklahoma.

"***Formation***." A layer of rock which has distinct characteristics that differs from nearby rock.

"***Fracturing***" or "***fracture stimulation techniques***." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"***Gross acres or gross wells***." The total acres or wells, as the case may be, in which a working interest is owned.

"***Held by production***." Acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or gas.

"***Holdco***." Mach Natural Resources Holdco LLC, a Delaware limited liability company.

"***Horizontal drilling***." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"***Hydraulic fracturing***." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"***Injection Wells***." A well in which fluids are injected rather than produced, the primary objective typically being to maintain reservoir pressure.

"***Intermediate***" Mach Natural Resources Intermediate LLC, a Delaware limited liability company.

"***Lease operating expense***." The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, ad valorem taxes, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

"***Legacy Producing Assets***." All of our legacy producing properties which are not in the Focus Drilling Area.

"***LNG***." Liquified natural gas.

"***LOE***." Lease operating expense.

"***Management Members***." Collectively refers to our current officers and employees who own indirect equity interests in the Mach Companies.

"***Mach Companies***." Collectively refers to BCE-Mach, BCE-Mach II, and BCE-Mach III.

"***Mach Companies Class B Units***." Class B Units of the Mach Companies.

"***Mach Resources***." Mach Resources LLC.

"***MBbl***." One thousand barrels of crude oil, condensate or NGLs.

"***MBoe***." One thousand Boe.

"***MBoe/d***." One thousand Boe per day.

"***Mcf***." One thousand cubic feet of natural gas.

"***MMbbl.***" One million barrels of oil.

"***MMBoe***." One million Boe.

"***MMBtu***." One million Btu.

"***MMcf***." One million cubic feet of natural gas.

"***MMcf/d***." One million cubic feet of natural gas per day.

"***NGLs***." Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

"***New Credit Facility***." The refers to the credit agreement governing the new reserve-based revolving credit facility that we will enter into in connection with the consummation of the Reorganization Transactions.

"***Net acres or net wells***." The percentage of total acres or wells an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"***NYMEX***." The New York Mercantile Exchange.

"***NYSE***." The New York Stock Exchange.

"***OGT***." ONEOK Gas Transmission.

"***OPEC***." Organization of the Petroleum Exporting Countries.

"***PCAOB***." The Public Company Accounting Oversight Board.

"***PDP***." Proved developed producing.

"***PEPL***." Panhandle Eastern Pipeline.

"***Possible reserves***." Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir. Where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

"***Probable reserves***." Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"***Productive well***." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"***Proved reserves***." Proved oil and natural gas 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 regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For a complete definition of proved crude oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

"***Proved undeveloped reserves ("PUD")***." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five years unless specific circumstances justify a longer time.

"***PV-10***." When used with respect to oil and natural gas reserves, PV-10 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, the most comparable measure under GAAP. 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.

"***Recompletion***." The process of re-entering an existing wellbore that is either producing or not producing and completing reservoirs in an attempt to establish or increase existing production.

"***Reservoir***." A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"***SEC Pricing***." The oil and gas price parameters established by the current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"***STACK***." Sooner Trend Anadarko Canadian Kingfisher.

"***Standardized Measure***." Standardized Measure is our standardized measure of discounted future net cash flows, which is 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. However, our operations are subject to the Texas franchise 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. 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.

"***Undeveloped acreage***." Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves.

"***Wellbore***." The hole drilled by the bit that is equipped for oil and natural gas production on a completed well. Also called well or borehole.

"***Working interest***." The right granted to the lessee of a property to explore for and to produce and own oil and natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"***Workover***." Operations on a producing well to restore or increase production.

"***WTI***." West Texas Intermediate.

Mach Natural Resources LP

Common Units
Representing Limited Partner Interests

PROSPECTUS

Joint Book-Running Managers

Stifel	**Raymond James**

Until , 2023 (25 days after the date of this prospectus), all dealers that buy, sell or trade our ordinary shares, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to its unsold allotments or subscriptions.

PART II
INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other expenses of issuance and distribution

The following table sets forth an itemized statement of the amounts of all expenses (excluding underwriting discounts and commissions) payable by us in connection with the registration of the common units offered hereby. With the exception of the SEC registration fee, FINRA filing fee and NYSE listing fee, the amounts set forth below are estimates.

SEC registration fee	$	*
FINRA filing fee	$	*
NYSE listing fee	$	*
Accountants' fees and expenses	$	*
Legal fees and expenses	$	*
Engineering expenses	$	*
Printing and engraving expenses	$	*
Transfer agent and registrar fees	$	*
Miscellaneous	$	*
Total	$	

* To be provided by amendment.

Item 14. Indemnification of Directors and Officers

Mach Natural Resources

Subject to any terms, conditions or restrictions set forth in the partnership agreement, Section 17108 of the Delaware Revised Uniform Limited Partnership Act empowers a Delaware limited partnership to indemnify and hold harmless any partner or other persons from and against any and all claims and demands whatsoever. The section of the prospectus entitled "The Partnership Agreement — Indemnification" discloses that we will indemnify officers, directors and affiliates of the general partner to the fullest extent permitted by law against all losses, claims, damages or similar events, unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that the applicable person 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 is incorporated herein by this reference.

The underwriting agreement to be entered into in connection with the sale of the securities offered pursuant to this registration statement, the form of which will be filed as an exhibit to this registration statement, provides for the indemnification of Mach Natural Resources and our general partner, their officers and directors, and any person who controls our general partner, including indemnification for liabilities under the Securities Act.

Mach Natural Resources GP LLC

Subject to any terms, conditions or restrictions set forth in the limited liability company agreement, Section 18-108 of the Delaware Limited Liability Company Act empowers a Delaware limited liability company to indemnify and hold harmless any member or manager or other person from and against any and all claims and demands whatsoever.

Under the amended and restated limited liability agreement of our general partner, in most circumstances, our general partner will indemnify the following persons, to the fullest extent permitted by law, from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings (whether civil, criminal, administrative or investigative):

- any person who is or was an affiliate of our general partner (other than us and our subsidiaries);
- any person who is or was a member, partner, officer, director, employee, agent or trustee of our general partner or any affiliate of our general partner;

- any person who is or was serving at the request of our general partner or any affiliate of our general partner as an officer, director, employee, member, partner, agent, fiduciary or trustee of another person; and
- any person designated by our general partner.

Our general partner will purchase insurance covering its officers and directors against liabilities asserted and expenses incurred in connection with their activities as officers and directors of our general partner or any of its direct or indirect subsidiaries.

Item 15. Recent Sales of Unregistered Securities

Prior to closing of the initial public offering, the Company will enter into a series of reorganization transactions pursuant to which all of BCE-Mach Aggregator, the Management Members and Mach Resources' respective membership interests in the Mach Companies will be exchanged for a pro rata allocation of 100% of the limited partner interests in the Company.

The above issuances did not involve any underwriters, underwriting discounts or commissions, or any public offering and we believe such issuances are exempt from the registration requirements of the Securities Act by virtue of Section 4(a)(2) thereof.

Item 16. Exhibits and financial statement schedules

Exhibit Number	Description
1.1*	Form of Underwriting Agreement
3.1*	Certificate of Limited Partnership of Mach Natural Resources LP
3.2*	Form of Amended and Restated Agreement of Limited Partnership of Mach Natural Resources LP (included as Appendix A)
3.4*	Form of Amended and Restated Limited Liability Company Agreement of Mach Natural Resources GP, LLC
5.1*	Opinion of Kirkland & Ellis LLP as to the legality of the securities being registered
8.1*	Opinion of Kirkland & Ellis LLP relating to tax matters
10.1*	Form of Mach Natural Resource GP, LLC 2023 Long-Term Incentive Plan
10.2*	Form of Contribution Agreement
10.3*	Form of Indemnification Agreement
10.4*	Form of New Credit Facility
10.5*	Form of Master Services Agreement
21.1*	List of Subsidiaries of Mach Natural Resources LP
23.1*	Consent of Grant Thornton LLP for BCE-Mach III LLC audited financial statements
23.2*	Consent of Grant Thornton LLP for BCE-Mach LLC audited financial statements
23.3*	Consent of Grant Thornton LLP for BCE-Mach II LLC audited financial statements
23.4*	Consent of Cawley, Gillespie & Associates
23.5*	Consent of Kirkland & Ellis LLP (contained in Exhibit 5.1)
23.6*	Consent of Kirkland & Ellis LLP (contained in Exhibit 8.1)
24.1*	Powers of Attorney (included on signature page)
99.1	Report of Cawley, Gillespie & Associates of reserves of BCE-Mach LLC, as of December 31, 2022
99.2	Report of Cawley, Gillespie & Associates of reserves of BCE-Mach II LLC, as of December 31, 2022
99.3	Report of Cawley, Gillespie & Associates of reserves of BCE-Mach III LLC, as of December 31, 2022
99.4	Report of Cawley, Gillespie & Associates of reserves, as of June 30, 2023
107*	Filing Fee Table

* To be filed by amendment.

Item 17. Undertakings

The undersigned registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question of whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, State of Oklahoma, on , 2023.

	Mach Natural Resources LP	
	By:	**Mach Natural Resources GP LLC, its general partner**
	By:	
	Name:	Tom L. Ward
	Title:	Chief Executive Officer

Each person whose signature appears below appoints Tom L. Ward and Kevin R. White, and each of them, any of whom may act without the joinder of the other, as his or her true and lawful attorneys in fact and agents, with full power of substitution and resubstitution, for him or her and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post effective amendments) to this Registration Statement and any Registration Statement (including any amendment thereto) for this offering that is to be effective upon filing pursuant to Rule 462(b) under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys in fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys in fact and agents or any of them or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and the dates indicated.

Name	Title	Date
Tom L. Ward	Chief Executive Officer and Director (principal executive officer)	, 2023
Kevin R. White	Chief Financial Officer (principal financial officer and principal accounting officer)	, 2023
William McMullen	Chairman of the Board	, 2023
	Director	, 2023
	Director	, 2023
	Director	, 2023

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

January 16, 2023

Paul Lupardus
Executive VP Engineering
Mach Resources
14201 Wireless Way
Oklahoma City, OK 73134

Re: Evaluation Summary – SEC Pricing
BCE-Mach I LLC Interests
Mississippian Region - Oklahoma and Kansas
Proved Reserves
As of December 31, 2022

Dear Mr. Lupardus:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the BCE-Mach I LLC ("Mach I") interests in properties located in the Mississippian Region of Oklahoma and Kansas. It is our understanding that the proved reserves estimated in this report constitute 100 percent of all proved reserves owned by Mach I.

This report, completed on January 16, 2023, utilized an effective date of December 31, 2022 and was prepared using constant prices and costs and conforms to Item 1202(a)(8) of Regulation S-K and the other rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). This report has been prepared for use in filings with the SEC. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the reserves are summarized below:

		Proved Developed Producing	Proved Undeveloped	Proved Developed Non-Producing	Proved Developed Shut-In	Proved
Net Reserves						
Oil	- Mbbl	11,476.9	4,842.8	151.5	0.0	16,471.3
Gas	- MMcf	209,753.9	42,129.6	2,266.2	0.0	254,149.7
NGL	- Mbbl	13,672.6	2,383.5	154.2	0.0	16,210.3
Revenue						
Oil	- M$	1,080,961.4	456,425.5	14,205.0	0.0	1,551,591.9
Gas	- M$	933,618.3	182,437.9	10,217.6	0.0	1,126,273.8
NGL	- M$	446,186.8	77,695.1	5,001.4	0.0	528,883.3
Severance and						
Ad Valorem Taxes	- M$	176,586.2	45,051.7	1,966.0	5.0	223,608.9
Operating Expenses	- M$	653,065.6	196,927.4	13,096.9	0.0	863,090.0
Investments	- M$	29,769.7	201,796.6	695.5	8,745.3	241,007.2
Operating Income (BFIT)	- M$	1,601,344.5	272,782.9	13,665.6	-8,750.3	1,879,043.6
Discounted at 10.0%	- M$	730,054.5	112,638.6	9,570.2	-2,293.5	849,970.0

As requested, we evaluated cases that comprise approximately 90% of the cumulative discounted cash flows of the proved developed producing reserves from the company's internal evaluation and 100% of the Miss Lime proved undeveloped reserves. We refer to these cases as "Major Properties", and composite reserve estimates and economic forecasts for these properties are summarized below:

		Proved Developed Producing	Proved Undeveloped	Major Proved
Net Reserves				
Oil	- Mbbl	9,781.6	4,842.8	14,624.4
Gas	- MMcf	174,141.0	42,129.6	216,270.5
NGL	- Mbbl	10,569.9	2,383.5	12,953.4
Revenue				
Oil	- M$	922,254.0	456,425.5	1,378,679.8
Gas	- M$	766,936.8	182,437.9	949,374.7
NGL	- M$	346,521.1	77,695.1	424,216.2
Severance and				
Ad Valorem Taxes	- M$	146,620.0	45,051.7	191,671.7
Operating Expenses	- M$	456,015.9	196,927.4	652,943.2
Investments	- M$	17,658.0	201,796.6	219,454.7
Operating Income (BFIT)	- M$	1,415,418.1	272,782.9	1,688,201.5

Discounted at 10.0%	- M$	629,028.9	112,638.6	741,667.4

The remaining cases are referred to as "Minor Properties", and the company's internal reserve estimates and economic forecasts for these properties are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In	Minor Proved
Net Reserves					
Oil	- Mbbl	1,695.4	151.5	0.0	1,846.9
Gas	- MMcf	35,613.0	2,266.2	0.0	37,879.2
NGL	- Mbbl	3,102.7	154.2	0.0	3,256.9
Revenue					
Oil	- M$	158,707.1	14,205.0	0.0	172,912.1
Gas	- M$	166,681.5	10,217.6	0.0	176,899.1
NGL	- M$	99,665.8	5,001.4	0.0	104,667.2
Severance and					
Ad Valorem Taxes	- M$	29,966.2	1,966.0	5.0	31,937.2
Operating Expenses	- M$	197,049.8	13,096.9	0.0	210,146.7
Investments	- M$	12,111.7	695.5	8,745.3	21,552.5
Operating Income (BFIT)	- M$	185,926.8	13,665.6	-8,750.3	190,842.0
Discounted at 10.0%	- M$	101,026.1	9,570.2	-2,293.5	108,302.9

In accordance with the SEC guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its "present worth". The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $6.36 per MMBtu and the annual average WTI Cushing spot oil price of $93.67 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for 12 months prior to the effective date of the evaluation. Oil and gas prices were held constant and were adjusted for each property based on historical differentials. NGL prices were forecast as fractions of the above SEC oil price. Deductions were applied to the net gas volumes for fuel and shrinkage. The adjusted volume-weighted average product prices over the life of the properties are $94.20 per barrel of oil, $4.43 per Mcf of gas, and $32.63 per barrel of NGL.

Operating expenses and capital costs were supplied by Mach Resources and reviewed for reasonableness. Severance taxes were forecast as 7.199% for the Oklahoma properties and 4.4% to 4.738% for the Kansas properties. Ad valorem taxes were forecast as 3% of net revenue for operated wells in Kansas. Neither expenses nor investments were escalated. Net plugging costs were scheduled as $50,000 per well. The plugging costs for shut-in wells with no remaining reserves are captured in the proved developed shut-in category.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Mach Resources. Ownership interests were supplied by Mach Resources and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc.

Cawley, Gillespie & Associates, Inc. is independent with respect to Mach Resources as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

Exhibit 99.2

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

January 16, 2023

Paul Lupardus
Executive VP Engineering
Mach Resources
14201 Wireless Way
Oklahoma City, OK 73134

Re: Evaluation Summary – SEC Pricing
BCE-Mach II LLC Interests
Texas and Oklahoma
Proved Developed Reserves
As of December 31, 2022

Dear Mr. Lupardus:

As requested, we are submitting our estimates of proved developed reserves and our forecasts of the resulting economics attributable to the BCE-Mach II LLC ("Mach II") interests in properties located in Texas and Oklahoma. It is our understanding that the proved developed reserves estimated in this report constitute 100 percent of all proved reserves owned by Mach II. We evaluated cases that comprise approximately 90% of the cumulative discounted cash flows of the proved developed producing ("PDP") reserves in this evaluation. We refer to these cases as the "Major PDP Properties". The remaining PDP cases are referred to as the "Minor PDP Properties" and represent the company's internal reserve estimates and economic forecasts. The minor proved developed non-producing and proved developed shut-in reserves are the company's internal forecasts as well.

This report, completed on January 16, 2023, utilized an effective date of December 31, 2022 and was prepared using constant prices and costs and conforms to Item 1202(a)(8) of Regulation S-K and the other rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). This report has been prepared for use in filings with the SEC. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the reserves are summarized below:

		Major Proved Developed Producing	Minor Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In	Total Proved Developed
Net Reserves						
Oil	- Mbbl	1,378.0	280.9	35.0	0.0	1,693.9
Gas	- MMcf	80,120.4	16,194.2	2,593.7	0.0	98,908.3
NGL	- Mbbl	5,652.6	919.4	123.2	0.0	6,695.2
Revenue						
Oil	- M$	129,695.2	26,250.9	3,290.2	0.0	159,236.3
Gas	- M$	368,185.1	79,798.7	12,689.1	0.0	460,672.9
NGL	- Mbbl	185,111.4	30,510.1	4,089.9	0.0	219,711.3
Severance and						
Ad Valorem Taxes	- M$	56,134.8	9,990.1	1,560.6	0.0	67,685.6
Operating Expenses	- M$	158,551.9	58,587.2	8,149.8	0.0	225,288.7
Investments	- M$	9,795.7	8,807.3	899.5	3,983.9	23,486.4
Operating Income (BFIT)	- M$	471,199.3	59,174.9	9,459.3	-3,983.9	535,849.6
Discounted at 10.0%	- M$	215,985.4	34,452.7	5,311.5	-919.7	254,830.0

In accordance with the SEC guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its "present worth". The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $6.36 per MMBtu and the annual average WTI Cushing spot oil price of $93.67 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for 12 months prior to the effective date of the evaluation. Oil and gas prices were held constant and were adjusted for each property based on historical differentials. NGL prices were forecast as fractions of the above SEC oil price. Deductions were applied to the net gas volumes for fuel and shrinkage. The adjusted volume-weighted average product prices over the life of the properties are $94.00 per barrel of oil, $4.66 per Mcf of gas, and $32.82 per barrel of NGL.

Operating expenses were supplied by Mach Resources and reviewed for reasonableness. Severance taxes were forecast by state based on statutory rates, and ad valorem taxes were forecast as 3.0% of net revenue for operated properties in Texas. Neither expenses nor investments were escalated. Net plugging costs were scheduled as $50,000 per well. The plugging costs for shut-in wells with no remaining reserves are captured in the proved developed shut-in category.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Mach Resources. Ownership interests were supplied by Mach Resources and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc.

Cawley, Gillespie & Associates, Inc. is independent with respect to Mach Resources as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers (“SPE Standards”). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

Exhibit 99.3

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

January 16, 2023

Paul Lupardus
Executive VP Engineering
Mach Resources
14201 Wireless Way
Oklahoma City, OK 73134

Re: Evaluation Summary – SEC Pricing
BCE-Mach III LLC Interests
Various Counties, Oklahoma
Proved Reserves
As of December 31, 2022

Dear Mr. Lupardus:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the BCE-Mach III LLC ("Mach III") interests in properties located in various counties in Oklahoma. It is our understanding that the proved reserves estimated in this report constitute 100 percent of all proved reserves owned by Mach III.

This report, completed on January 16, 2023, utilized an effective date of December 31, 2022 and was prepared using constant prices and costs and conforms to Item 1202(a)(8) of Regulation S-K and the other rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). This report has been prepared for use in filings with the SEC. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the reserves are summarized below:

		Proved Developed Producing	Proved Undeveloped	Proved Developed Non-Producing	Proved Developed Shut-In	Proved
Net Reserves						
Oil	- Mbbl	27,654.7	18,595.4	2,329.7	0.0	48,579.8
Gas	- MMcf	514,590.0	102,251.0	12,778.9	0.0	629,619.9
NGL	- Mbbl	38,470.8	7,594.5	767.8	0.0	46,833.1
Revenue						
Oil	- M$	2,583,656.4	1,745,193.6	217,297.7	0.0	4,546,147.7
Gas	- M$	2,777,450.0	556,961.9	59,700.4	0.0	3,394,112.3
NGL	- M$	1,430,461.8	271,295.3	24,619.7	0.0	1,726,376.8
Other	- M$	0.0	0.0	0.0	0.0	0.0
Severance and						
Ad Valorem Taxes	- M$	553,494.4	151,103.0	20,308.5	0.0	724,905.8
Operating Expenses	- M$	1,930,094.6	433,523.1	54,944.0	0.0	2,418,561.7
Investments	- M$	140,709.9	669,535.3	15,404.0	50,465.2	876,114.4
Operating Income (BFIT)	- M$	4,167,271.9	1,319,289.9	210,961.3	-50,465.2	5,647,057.9
Discounted at 10.0%	- M$	2,247,368.4	610,986.3	110,527.9	-15,375.9	2,953,506.7

As requested, we evaluated cases that comprise approximately 90% of the cumulative discounted cash flows of the proved developed producing reserves and 100% of the proved undeveloped reserves from the company's internal evaluation of the upstream cases. We refer to these cases as the "Major Upstream" properties, and composite reserve estimates and economic forecasts for these properties are summarized below:

		Proved Developed Producing	Proved Undeveloped
Net Reserves			
Oil	- Mbbl	24,467.0	18,595.4
Gas	- MMcf	405,312.4	102,251.0
NGL	- Mbbl	30,606.3	7,594.5
Revenue			
Oil	- M$	2,286,505.7	1,745,193.6
Gas	- M$	1,736,231.4	401,126.5
NGL	- M$	1,052,449.4	271,295.3
Severance and			
Ad Valorem Taxes	- M$	372,633.5	151,103.0
Operating Expenses	- M$	1,136,585.6	445,574.5

Investments	- M$	41,837.2	669,535.3
Operating Income (BFIT)	- M$	3,524,130.0	1,151,403.0
Discounted at 10.0%	- M$	1,759,421.4	529,151.7

The remaining upstream cases are referred to as the "Minor Upstream" properties, and the company's internal reserve estimates and economic forecasts for these properties are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In
Net Reserves				
Oil	- Mbbl	3,187.8	2,329.7	0.0
Gas	- MMcf	109,277.5	12,778.9	0.0
NGL	- Mbbl	7,864.5	767.8	0.0
Revenue				
Oil	- M$	297,151.6	217,297.7	0.0
Gas	- M$	516,036.4	59,700.4	0.0
NGL	- M$	287,736.2	24,619.7	0.0
Severance and				
Ad Valorem Taxes	- M$	87,275.7	20,308.5	0.0
Operating Expenses	- M$	369,816.8	54,944.0	0.0
Investments	- M$	98,872.7	15,404.0	50,465.2
Operating Income (BFIT)	- M$	544,959.6	210,961.3	-50,465.2
Discounted at 10.0%	- M$	322,802.4	110,527.9	-15,375.9

Composite forecasts of revenues and expenses for a company-owned plant, gas gathering and water disposal system are summarized below:

		Proved Developed Producing Midstream	Proved Undeveloped Midstream	Total Proved Midstream
Net Reserves				
Oil	- Mbbl	0.0	0.0	0.0
Gas	- MMcf	0.0	0.0	0.0
NGL	- Mbbl	0.0	0.0	0.0
Revenue				
Oil	- M$	0.0	0.0	0.0
Gas	- M$	525,182.3	155,835.5	681,017.8
NGL	- M$	90,276.3	0.0	90,276.3
Other	- M$	0.0	0.0	0.0
Severance and				
Ad Valorem Taxes	- M$	93,585.3	0.0	93,585.3
Operating Expenses	- M$	423,694.7	-12,051.4	411,643.4
Investments	- M$	0.0	0.0	0.0
Operating Income (BFIT)	- M$	98,178.6	167,886.8	266,065.4
Discounted at 10.0%	- M$	165,144.6	81,834.7	246,979.3

The above revenues and expenses are limited to those associated only with Mach III volumes. No revenues resulting from the gathering or processing of third party volumes are included.

In accordance with the SEC guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its "present worth". The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $6.36 per MMBtu and the annual average WTI Cushing spot oil price of $93.67 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for 12 months prior to the effective date of the evaluation. Oil and gas prices were held constant and were adjusted for each property based on historical differentials. NGL prices were forecast as fractions of the above SEC oil price. Deductions were applied to the net gas volumes for fuel and shrinkage. The adjusted volume-weighted average product prices over the life of the properties are $93.58 per barrel of oil, $5.39 per Mcf of gas, and $36.86 per barrel of NGL.

Operating expenses and capital costs were supplied by Mach Resources and reviewed for reasonableness. Severance taxes were forecast as 7.199% for oil, gas and NGL with 3-year partial abatements for new wells. Neither expenses nor investments were escalated. Net plugging costs were scheduled as $50,000 per well. The plugging costs for shut-in wells with no remaining reserves are captured in the proved developed shut-in category.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Mach Resources. Ownership interests were supplied by Mach Resources and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc.

Cawley, Gillespie & Associates, Inc. is independent with respect to Mach Resources as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

Exhibit 99.4

Cawley, Gillespie & Associates, Inc.

petroleum consultants

6500 RIVER PLACE BLVD, BLDG 3 SUITE 200
AUSTIN, TEXAS 78730
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4905
817- 336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5017
713-651-9944

July 7, 2023

Paul Lupardus
Executive VP Engineering
Mach Natural Resources LP
14201 Wireless Way
Oklahoma City, OK 73134

Re: Evaluation Summary – SEC Pricing
Mach Natural Resources LP Interests
Oklahoma, Texas and Kansas
Proved + Probable Reserves
As of June 30, 2023

Dear Mr. Lupardus:

As requested, we are submitting our estimates of proved and probable reserves and our forecasts of the resulting economics attributable to the Mach Natural Resources LP ("Mach") interests in properties located in Oklahoma, Texas and Kansas. It is our understanding that the proved and probable reserves estimated in this report constitute 100 percent of all proved and probable reserves owned by Mach.

This report, completed on July 7, 2023, utilized an effective date of June 30, 2023, and was prepared using constant prices and costs and conforms to Item 1202(a)(8) of Regulation S-K and the other rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). This report has been prepared for use in filings with the SEC. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the reserves are summarized below:

		Proved Developed Producing	Proved Undeveloped	Proved Developed Non-Producing	Proved Developed Shut-In	Proved	Probable
Net Reserves							
Oil	- Mbbl	40,128.1	12,152.7	748.3	0.0	53,029.1	72,867.9
Gas	- MMcf	770,958.8	28,780.6	11,767.8	0.0	811,507.2	373,476.6
NGL	- Mbbl	49,419.4	721.2	770.2	0.0	50,910.9	19,576.4
Revenue							
Oil	- M$	3,298,211.1	1,005,403.8	61,234.1	0.0	4,364,848.5	6,013,997.8
Gas	- M$	2,481,083.8	133,758.6	29,711.6	0.0	2,644,553.5	1,439,227.5
NGL	- M$	1,277,443.2	18,557.5	17,444.7	0.0	1,313,445.3	477,907.8
Other	- M$	49,264.8	0.0	0.0	0.0	49,264.8	0.0
Severance and Ad Valorem Taxes	- M$	584,740.7	70,217.7	8,072.2	5.0	663,035.7	461,346.5
Operating Expenses	- M$	2,582,804.8	203,044.1	30,256.4	0.0	2,816,105.6	1,727,071.0
Investments	- M$	196,080.7	265,084.0	10,066.6	61,254.1	532,485.5	2,457,846.7
Operating Income (BFIT)	- M$	3,742,376.1	619,374.0	59,995.2	-61,259.2	4,360,486.0	3,284,870.0
Discounted at 10.0%	- M$	2,125,026.0	303,643.2	14,546.2	-8,116.0	2,435,098.0	1,039,202.5

We evaluated cases that comprise approximately 90% of the cumulative discounted cash flows of the proved developed producing reserves and 100% of the proved and probable undeveloped reserves from the company's internal evaluation of the upstream cases. We refer to these cases as the "Major Upstream" properties, and composite reserve estimates and economic forecasts for these properties are summarized below:

		Proved Developed Producing	Proved Undeveloped	Probable Undeveloped
Net Reserves				
Oil	- Mbbl	36,153.9	12,152.7	72,867.9
Gas	- MMcf	599,175.2	28,780.6	373,476.6
NGL	- Mbbl	38,117.8	721.2	19,576.4
Revenue				
Oil	- M$	2,975,427.0	1,005,403.8	6,013,997.8
Gas	- M$	1,459,912.7	98,307.9	910,763.6
NGL	- M$	908,041.2	18,557.5	477,907.8
Other	- M$	0.0	0.0	0.0

Severance and Ad Valorem Taxes	- M$	384,803.6	70,217.7	461,346.4
Operating Expenses	- M$	1,566,246.6	207,434.3	1,742,571.8
Investments	- M$	66,785.8	265,084.0	2,457,846.7
Operating Income (BFIT)	- M$	3,325,545.7	579,533.2	2,740,906.1
Discounted at 10.0%	- M$	1,731,683.7	283,337.5	859,629.2

The remaining upstream cases are referred to as the "Minor Upstream" properties, and the company's internal reserve estimates and economic forecasts for these properties are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed Shut-In
Net Reserves				
Oil	- Mbbl	3,974.3	748.3	0.0
Gas	- MMcf	171,783.5	11,767.8	0.0
NGL	- Mbbl	11,301.6	770.2	0.0
Revenue				
Oil	- M$	322,783.4	61,234.1	0.0
Gas	- M$	447,748.4	29,711.6	0.0
NGL	- M$	291,008.9	17,444.7	0.0
Other	- M$	0.0	0.0	0.0
Severance and Ad Valorem Taxes	- M$	82,370.4	8,072.2	5.0
Operating Expenses	- M$	476,565.5	30,256.4	0.0
Investments	- M$	129,294.9	10,066.6	61,254.1
Operating Income (BFIT)	- M$	373,309.8	59,995.2	-61,259.2
Discounted at 10.0%	- M$	235,359.2	14,546.2	-8,116.0

Composite forecasts of revenues and expenses for company-owned plants, gas gathering systems and water disposal systems are summarized below:

		Major Proved Developed Producing Midstream	Minor Proved Developed Producing Midstream	Proved Undeveloped Midstream	Total Proved Midstream	Probable Midstream
Net Reserves						
Oil	- Mbbl	0.0	0.0	0.0	0.0	0.0
Gas	- MMcf	0.0	0.0	0.0	0.0	0.0
NGL	- Mbbl	0.0	0.0	0.0	0.0	0.0
Revenue						
Oil	- M$	0.0	0.0	0.0	0.0	0.0
Gas	- M$	573,422.4	0.0	35,450.7	608,873.1	528,464.0
NGL	- M$	78,393.0	0.0	0.0	78,393.0	0.0
Other	- M$	10,063.9	39,200.8	0.0	49,264.8	0.0
Severance and Ad Valorem Taxes	- M$	117,566.8	0.0	0.0	117,566.8	0.0
Operating Expenses	- M$	510,890.4	29,104.5	-4,390.2	535,604.8	-15,500.9
Investments	- M$	0.0	0.0	0.0	0.0	0.0
Operating Income (BFIT)	- M$	33,422.2	10,098.2	39,840.8	83,361.3	543,965.0
Discounted at 10.0%	- M$	153,317.9	4,664.2	20,305.6	178,287.8	179,573.4

The above revenues and expenses are limited to those associated only with Mach volumes. No revenues resulting from the gathering or processing of third party volumes are included. The minor proved developed producing revenues and expenses are from the company's internal evaluation of the midstream cases.

In accordance with the SEC guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its "present worth". The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $4.763 per MMBtu and the annual average WTI Cushing spot oil price of $82.82 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for 12 months prior to the effective date of the evaluation. Oil and gas prices were held constant and were adjusted for each property based on historical differentials. NGL prices were forecast as fractions of the above oil price. Deductions were applied to the net gas volumes for fuel and shrinkage. The adjusted volume-weighted average product prices over the life of the properties are $82.31 per barrel of oil, $3.26 per Mcf of gas, and $25.80 per barrel of NGL.

Operating expenses and capital costs were supplied by Mach and reviewed for reasonableness. Severance taxes were forecast by state based on statutory rates, and ad valorem taxes were forecast as 3.0% of net revenue for operated properties in Texas and Kansas. Neither expenses nor investments were escalated. Net plugging costs were scheduled as $50,000 per well. The plugging costs for shut-in wells with no remaining reserves are captured in the proved developed shut-in category.

The proved and probable reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Mach Natural Resources LP. Ownership interests were supplied by Mach Natural Resources LP and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc.

Cawley, Gillespie & Associates, Inc. is independent with respect to Mach Natural Resources LP as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

/s/ J. Zane Meekins

J. Zane Meekins, P.E.
Executive Vice President

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

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