As filed with the Securities and Exchange Commission on April 14, 2023

Registration No. 333-268469

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT NO. 4
TO

FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

BKV CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**85-0886382**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

1200 17th Street, Suite 2100
Denver, Colorado 80202
(720) 375-9680
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Christopher P. Kalnin
Chief Executive Officer
BKV Corporation
1200 17th Street, Suite 2100
Denver, Colorado 80202
(720) 375-9680
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Samantha H. Crispin	**Michael Chambers**
M. Preston Bernhisel	**Monica E. White**
Adorys Velazquez	**Latham & Watkins LLP**
Baker Botts L.L.P.	**811 Main Street, Suite 3700**
2001 Ross Avenue, Suite 900	**Houston, Texas 77002**
Dallas, Texas 75201	**(713) 546-5400**
(214) 953-6500	

Approximate date of commencement of proposed sale 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, please 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 which 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 the 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

Shares

BKV Corporation

Common Stock

This is the initial public offering of common stock of BKV Corporation, a Delaware corporation. Prior to this offering, there has been no public market for our common stock. We anticipate that the initial public offering price will be between $ and $ per share. We have applied to list our common stock on the New York Stock Exchange ("NYSE") under the symbol "BKV."

We have granted the underwriters a 30-day option to purchase up to additional shares from us at the initial public offering price, less the underwriting discounts and commissions.

We are an "emerging growth company" as the term is used in the Jumpstart Our Business Startups Act of 2012 and, as such, have elected to comply with certain reduced public company reporting requirements. See "*Prospectus Summary—Implications of Being an Emerging Growth Company.* "

Upon completion of this offering, affiliates of Banpu Public Company Limited will beneficially own approximately % of the voting power of the outstanding shares of our common stock. As a result, we will be a "controlled company" within the meaning of the NYSE rules. See "*Management—Controlled Company.*"

Investing in our common stock involves risks, including those described under "*Risk Factors*" beginning on page **42** **of this prospectus.**

	Price to Public	Underwriting Discounts and Commissions(1)	Proceeds to BKV Corporation
Per Share	$	$	$
Total	$	$	$

(1) The underwriters will also be reimbursed for certain expenses incurred in this offering. See "*Underwriting*" for additional information regarding underwriting compensation.

Neither the Securities and Exchange Commission nor any 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 shares of our common stock on or about , 2023.

Joint Book-Running Managers

Credit Suisse	**BofA Securities**	**Barclays**
Citigroup	**Evercore ISI**	**Jefferies**

Co-Managers

TPH&Co.	**Susquehanna Financial Group, LLLP**	**SMBC Nikko**

The date of this prospectus is , 2023.


BKV
Straight.
Forward.
Energy.

TABLE OF CONTENTS

Dealer Prospectus Delivery Obligation

Through and including , 2023 (the 25th day after the date of this prospectus), all dealers that effect transactions in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This delivery requirement is in addition to a dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

You should rely only on the information contained in this prospectus or in any free writing prospectus that we authorize to be distributed to you. We and the underwriters have not authorized anyone to provide you with any information other than that contained in this prospectus or in any free writing prospectus prepared by or on behalf of us or to which we have referred you, and neither we, nor the underwriters take responsibility for any other information others may give you. We are offering to sell, and seeking offers to buy, shares of our common stock only in jurisdictions where such offers and sales are permitted. The information in this prospectus or any free writing prospectus is accurate only as of its date, regardless of its time of delivery or the time of any sale of shares of our common stock. Our business, financial condition, results of operations and prospects may have changed since that date.

Industry and Market Data

In this prospectus, we present certain market and industry data. This information is based on third-party sources which we believe to be reliable as of their respective dates. Neither we nor the underwriters have independently verified any third-party information. Some data is also based on our good faith estimates. Expectations of our and our industry's future performance are necessarily subject to a high degree of uncertainty and risk due to a variety of factors, including those described in "*Risk Factors*." These and other factors could cause future performance to differ materially from our expectations. See "*Cautionary Statement Regarding Forward-Looking Statements*."

Presentation of Financial, Reserve and Operating Data

Unless indicated otherwise, the historical financial information presented in this prospectus is that of BKV Corporation and its consolidated subsidiaries as of December 31, 2022. The pro forma financial information presented in this prospectus presents the combination of the historical consolidated financial statements of the Company, as adjusted to give effect to the Exxon Barnett Acquisition, the related financing under the Term Loan Credit Agreement and the $75 Million Loan Agreement (each as defined herein). Please see "*Unaudited Pro Forma Combined Consolidated Financial Statements*" included elsewhere in this prospectus.

The historical natural gas, NGL and oil reserves data presented in this prospectus as of December 31, 2022, 2021 and 2020 is based on the reserve reports prepared by Ryder Scott Company, L.P., independent petroleum engineers.

In addition, unless indicated otherwise, the operational data presented in this prospectus is that of BKV Corporation and its consolidated subsidiaries on a consolidated basis as of and for the periods presented.

As a result of our acquisition transactions in recent years, our historical operating, financial and reserve data may not be comparable between periods presented in this prospectus. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors that Affect Comparability of Our Results of Operations*."

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 SM 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 rights of the applicable licensor to these trademarks, service marks and trade names.

Rounding and Percentages

The financial information and certain other information presented in this prospectus have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables in this prospectus. In addition, certain percentages presented in this prospectus reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers or may not sum due to rounding.

Other Considerations

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. See "*Risk Factors*" and "*Cautionary Statement Regarding Forward-Looking Statements*" for additional information regarding these risks.

You should read this prospectus and any written communication prepared by us or on our behalf in connection with this offering, together with the additional information described in the section of this prospectus titled "*Where You Can Find More Information*." We have not authorized anyone to provide you with information or to make any representation in connection with this offering other than those contained herein. If anyone makes any recommendation or gives any information or representation regarding this offering, you should not rely on that recommendation, information or representation as having been authorized by us, the underwriters or any other person on our behalf. The information contained in this prospectus is accurate only as of the date of which it is shown, or if no date is otherwise indicated, the date of this prospectus, regardless of the time of delivery of this prospectus or of any sale of our shares of common stock. We are offering to sell, and seeking offers to buy, shares of common stock only in jurisdictions where offers and sales are permitted. Our business, financial condition, results of operations and prospects may have changed since that date. Information contained on our website is not part of this prospectus.

No action is being taken in any jurisdiction outside the United States to permit a public offering of shares of common stock or possession or distribution of this prospectus in that jurisdiction. Persons who come into possession of this prospectus in jurisdictions outside the United States are required to inform themselves about and to observe any restrictions as to this offering and the distribution of this prospectus applicable to that jurisdiction.

Glossary of Oil and Natural Gas Terms

The following are abbreviations and definitions of certain terms used in this prospectus, which are commonly used in the oil and natural gas industry:

"***Bbl***" refers to one stock tank barrel, of 42 U.S. gallons liquid volume, used in this prospectus in reference to crude oil or other liquid hydrocarbons.

"***Bcf***" refers to one billion cubic feet of natural gas or CO_2.

"***Bcfe***" refers to one billion cubic feet of natural gas equivalent.

"***Btu***" refers to British thermal unit, which is the heat required to raise the temperature of one pound of liquid water by one degree Fahrenheit.

"***CCUS***" refers to carbon capture, utilization and sequestration.

"***CO_2***" refers to carbon dioxide.

"***CO_2e***" refers to carbon dioxide equivalent.

"***developed acreage***" refers to the number of acres that are allocated or assignable to productive wells or wells capable of production.

"***developed 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 required equipment is relatively minor compared to the cost of a new well or (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.

"***dry hole***" refers to 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.

"***Effective NRI***" refers to our share of leasehold ownership after all burdens, such as royalty and overriding royalty interests, have been deducted from the working interest, weighted by our net acres owned in the Barnett from the assets acquired in the Devon Barnett Acquisition and the Exxon Barnett Acquisition.

"***gross acres***," "***gross acreage***" or "***gross wells***" refers to the total acres, acreage or wells, as the case may be, in which a working interest is owned.

"***IPIECA***" refers to the International Petroleum Industry Environmental Conservation Association.

"***lean gas***" refers to natural gas that contains a few or no liquefiable liquid hydrocarbons.

"***LNG***" refers to liquefied natural gas.

"***Maintenance Reinvestment Rate***" for any period refers to the maximum rate of our total cash paid for upstream capital expenditures (excluding leasehold costs and acquisitions) for such period as a percentage of Adjusted EBITDAX for the same period that is necessary to hold our production for such period flat.

"***MBbls***" refers to one thousand barrels of crude oil or other liquid hydrocarbons.

"***Mcf***" refers to one thousand cubic feet.

"***Mcf/d***" refers to one thousand cubic feet per day.

"***Mcfe***" refers to one thousand cubic feet of natural gas equivalent.

"***MMBtu***" refers to one million Btus.

"***MMcf***" refers to one million cubic feet.

"***MMcf/d***" refers to one million cubic feet per day.

"***MMcfe***" refers to one million cubic feet of natural gas equivalent, calculated by converting barrels of crude oil or other liquid hydrocarbons to natural gas at a ratio of one Bbl to six Mcf of natural gas. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

"***MMcfe/d***" refers to one million cubic feet of natural gas equivalent per day.

"***Mtpa***" refers to million metric tons of LNG per year.

"***Mtpy***" refers to million metric tons per year.

"***net acres***" refers to the percentage of total acres an owner has out of a particular number of acres, or a specified tract. For example, an owner who has 50% interest in 100 acres owns 50 net acres.

"***net operated development well***" refers to a gross operated development well that has been drilled, proportionately reduced by our working interest in such well.

"***NGL***" refers to natural gas liquids.

"***NYMEX***" refers to the New York Mercantile Exchange.

"***OPEC***" refers to the Organization of the Petroleum Exporting Countries.

"***possible reserves***" refers to 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***" refers to 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. 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. Where direct observation has defined an 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.

"***proved developed non-producing reserves***" refers to proved developed reserves expected to be recovered from (i) completion intervals that are open at the time of the estimate but which have not yet started producing, (ii) wells which were shut-in for market conditions or pipeline connections, (iii) wells not capable of production for mechanical reasons or (iv) zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves, in each case, which production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. While not a requirement for disclosure under SEC regulations, proved developed non-producing reserves have been sub-classified and calculated by Ryder Scott in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

"***proved developed producing reserves***" or "***PDP reserves***" refers to quantities of proved developed reserves expected to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation. While not a requirement for disclosure under SEC regulations, PDP reserves have been sub-classified and calculated by Ryder Scott in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

"***proved reserves***" refers to quantities of oil and 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. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined an HKO elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (a) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (b) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"***PUD reserves***" refers to proved undeveloped reserves.

"***rich gas***" refers to natural gas containing heavier hydrocarbons than a lean gas.

"***Scope 1 emissions***" refers to direct GHG emissions that occur from sources that are controlled or owned by an organization.

"***Scope 2 emissions***" refers to indirect GHG emissions associated with the purchase of electricity, steam, heat or cooling.

"***Scope 3 emissions***" refers to GHG emissions, as estimated per Category 11 (Use of Sold Product), that result from the end use of an organization's products, as well as emissions from other business activities from assets not owned or controlled by the organization but that the organization indirectly impacts in its value chain.

"***Tcfe***" refers to one trillion cubic feet of natural gas equivalent.

"***undeveloped acreage***" refers to acreage under lease on which wells have not been drilled or completed such that there is not production of commercial quantities of hydrocarbons.

"***undeveloped reserves***" are reserves of any category 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. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

"***Upstream Reinvestment Rate***" for any period refers to our total cash paid for upstream capital expenditures (excluding leasehold costs and acquisitions) for such period as a percentage of Adjusted EBITDAX for the same period.

"***working interest***" refers to the right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Commonly Used Defined Terms

As used in this prospectus, unless the context indicates or otherwise requires, the terms listed below have the following meanings:

"***Banpu***" refers to our sponsor, Banpu Public Company Limited, a public company listed on the Stock Exchange of Thailand and the ultimate parent company of BKV Corporation, Banpu, Banpu Power and BPPUS.

"***Banpu Power***" refers to Banpu Power Public Company Limited, a public company listed on the Stock Exchange of Thailand. Banpu owns approximately 78.66% of Banpu Power as of December 31, 2022.

"***Barnett***" refers to the Barnett Shale in the Fort Worth Basin of Texas.

"***BKV Barnett***" refers to BKV Barnett LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV Chaffee***" refers to BKV Chaffee Corners, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV Chelsea***" refers to BKV Chelsea, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV dCarbon Ventures***" refers to BKV dCarbon Ventures, LLC, a Delaware limited liability company and the CCUS business of BKV Corporation.

"***BKVerde***" refers to BKVerde, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV dCarbon Ventures.

"***BKV Midstream***" refers to BKV Midstream, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV O&G***" refers to BKV Oil and Gas Capital Partners, L.P., a Delaware limited partnership and wholly owned subsidiary of BKV Corporation, which was dissolved on September 19, 2022, on which date all ownership interests in subsidiaries of BKV O&G were assigned to BKV Corporation.

"***BKV Operating***" refers to BKV Operating, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV-BPP Power***" or "***BKV-BPP Power Joint Venture***" refers to BKV-BPP Power LLC, a Delaware limited liability company and the joint venture between BKV Corporation and BPPUS, in which we own a 50% interest.

"***BKV-BPP Retail***" refers to BKV-BPP Retail, LLC, a Delaware limited liability company and wholly owned subsidiary of the BKV-BPP Power Joint Venture.

"***BNAC***" refers to Banpu North America Corporation, a subsidiary of Banpu, our sponsor, and the majority stockholder of BKV Corporation.

"***BPPUS***" refers to Banpu Power US Corporation, a wholly owned subsidiary of Banpu Power and the owner of a 50% interest in the BKV-BPP Power Joint Venture.

"***bylaws***" refers to the amended and restated bylaws of BKV Corporation to be adopted in connection with the consummation of this offering.

"***certificate of incorporation***" refers to the second amended and restated certificate of incorporation of BKV Corporation to be adopted in connection with the consummation of this offering.

"***Code***" means the Internal Revenue Code of 1986, as amended.

"***Data Lake***" refers to a centralized cloud, large data technology that stores all company data and enables dashboards, visualizations, and analytics from a variety of systems and inputs.

"***Devon Barnett Acquisition***" refers to our acquisition of more than 289,000 net acres, 3,850 producing operated wells and related upstream assets in the Barnett from Devon Energy Corporation, which closed in October 2020.

"***ERCOT***" refers to the Electric Reliability Council of Texas.

"***ESG***" refers to environmental, social and governance.

"***Exxon Barnett Acquisition***" refers to our acquisition of approximately 165,000 net acres, 2,100 operated wells and related natural gas upstream, midstream and other assets in the Barnett from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation, which closed on June 30, 2022.

"***FID***" refers to final investment decision.

"***GAAP***" refers to generally accepted accounting principles in the United States.

"***GHG***" refers to greenhouse gases.

"***governing documents***" refers to our certificate of incorporation and our bylaws.

"***HRCO***" refers to a contract for the financial purchase and sale of power based on a floating price of natural gas at a predetermined location using a predetermined conversion factor, or heat rate, required to turn the fuel input into electricity.

"***Kalnin Ventures***" refers to Kalnin Ventures LLC, a Colorado limited liability company and wholly owned subsidiary of BKV Corporation.

"***NEPA***" refers to the Marcellus Shale in the Appalachian Basin of Northeast Pennsylvania.

"***net zero***" refers to the full elimination and/or offset of Scope 1, Scope 2 and/or Scope 3 emissions, as applicable, from our owned and operated upstream businesses.

"***NGP***" refers to natural gas processing.

"***Ryder Scott***" refers to Ryder Scott Company, L.P., independent petroleum engineers.

"***SREC***" refers to Solar Renewable Energy Credit, which represents a form of environmental attribute associated with solar energy generation, which can be marketed for financial gain to improve project economics or retired to offset the SREC owners' Scope 2 emissions. For every 1000 kilowatt-hours of electricity produced by an eligible solar facility, one SREC is awarded. For a solar facility to be credited with that SREC, the system must be certified and registered by state agencies.

"***Temple I***" refers to the combined gas turbine and steam turbine power plant located in Temple, Texas and owned by the BKV-BPP Power Joint Venture.

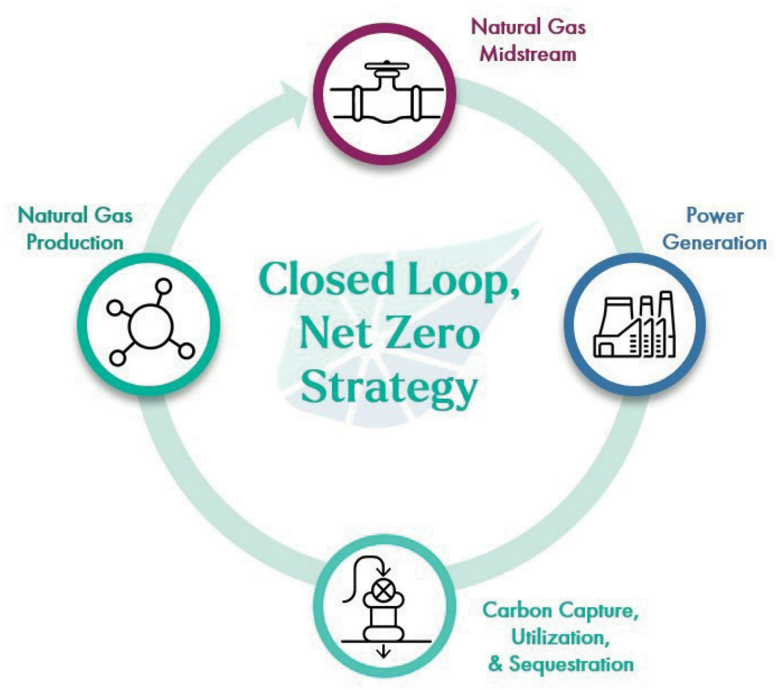
PROSPECTUS SUMMARY

This summary highlights certain information about us and this offering contained elsewhere in this prospectus, but it is not complete and does not contain all of the information you should consider before making an investment decision. In addition to this summary, you should read this entire prospectus carefully, including the sections titled "Risk Factors," "— Summary Historical and Unaudited Pro Forma Financial Information," "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our historical consolidated financial statements and the related notes thereto included elsewhere in this prospectus, before making an investment decision. This summary contains forward-looking statements that involve risks and uncertainties. See "Cautionary Statement Regarding Forward-Looking Statements." References in this prospectus to "BKV," the "Company," "we," "us," "our" and like terms are to BKV Corporation, a Delaware corporation, and its wholly owned subsidiaries, unless the context otherwise requires or we otherwise state.

Our Company

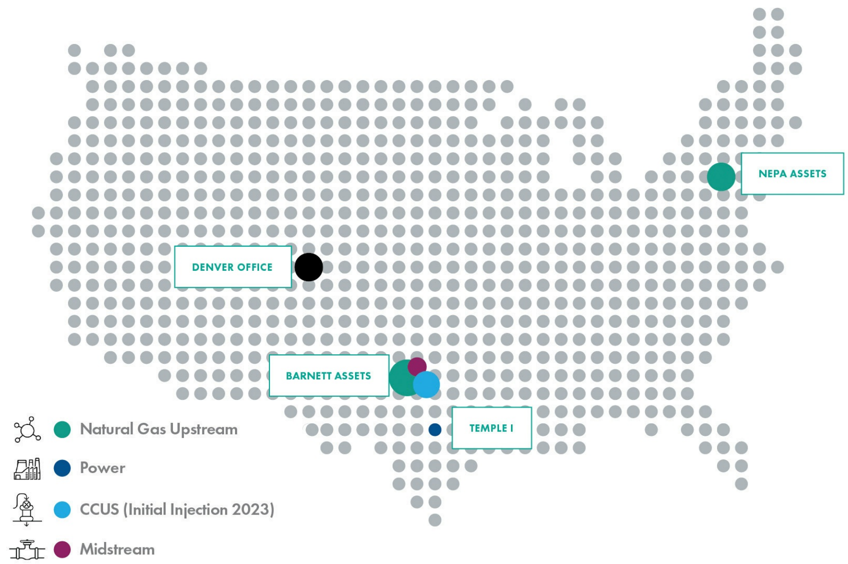
Overview

We are a forward thinking, growth driven energy company focused on creating value for our stockholders through the organic development of our properties as well as accretive acquisitions. Our core business is to produce natural gas from our owned and operated upstream businesses, which we expect to achieve net zero Scope 1 and Scope 2 emissions by the end of 2025, and net zero Scope 1, 2 and 3 emissions from our owned and operated upstream business by the early 2030s. We maintain a "closed-loop" approach to our net zero emissions goal with our four business lines: natural gas production, natural gas gathering, processing and transportation (our "natural gas midstream business"), power generation, and carbon capture, utilization and sequestration ("CCUS"). We are committed to building a vertically integrated business to reduce costs and improve overall commercial optimization of the full value chain. For instance, our natural gas production in the Barnett is gathered and transported through our midstream systems, and we are seeking to establish arrangements to supply our natural gas production directly to the BKV-BPP Power Joint Venture. We believe that our differentiated business model, net zero emissions focus, highly experienced management team and technology-driven approach to operating our business will enable us to create stockholder value.


Natural Gas
Midstream
Power
Generation
Carbon Capture,
Utilization,
& Sequestration
Natural Gas
Production
Closed Loop,
Net Zero
Strategy

We understand the impact climate change has on our community, the world and future generations, which is why addressing these impacts in how energy is produced is a top priority. In particular, it is one of our core values, “Be One BKV,” to create a unified team with a shared vision to achieve our emission reduction and energy impact goals.

BKV Assets



Overview of BKV Assets

Natural Gas

	Twelve Months Ending Dec '22 Net Production (MMcfe/d)	Dec '22 SEC 1P Reserves (Tcfe)	Producing Wells[1]	Net Acres
Barnett	733	5.24	6,926	458,000
NEPA	139	0.90	411	37,000
Total	872	6.14	7,337	495,000

Operated Midstream

	As of Dec '22 Throughput (Mmcf/d)	Pipeline Miles	Midstream Compressors
Barnett	220	778	65

Power

	Location	Heat Rate Btu/kWh	Capacity MW+
Temple 1	Bell County, TX	6,950	755

[1] Includes producing wells in which BKV has an ORRI or Non-Operated interest

Our Operations

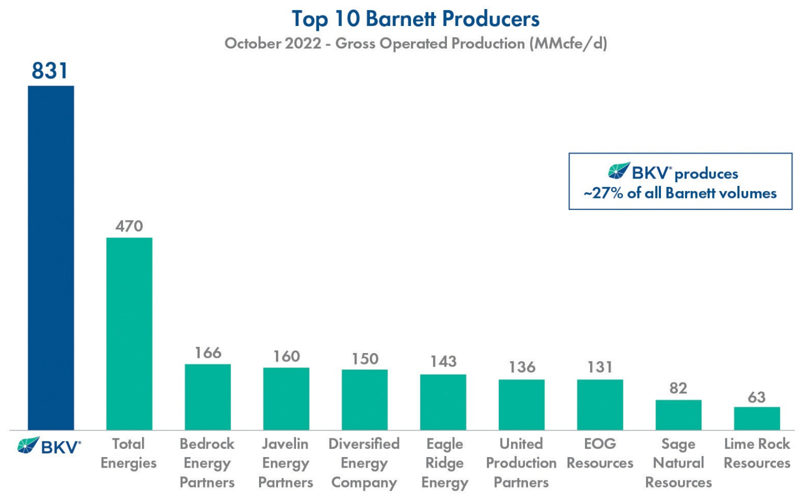
Natural Gas Production

We are engaged in the acquisition, operation and development of natural gas and NGL properties primarily located in the Barnett Shale in the Fort Worth Basin of Texas (the “Barnett”) and in the Marcellus Shale in the Appalachian Basin of Northeastern Pennsylvania (“NEPA”). Our upstream assets are the core of our business and provide us with substantial Adjusted Free Cash Flow, which we expect will be sufficient to fund our upstream, midstream and power capital expenditure program while maintaining a conservative balance sheet. We have a balanced portfolio of low decline producing properties and undeveloped inventory, primarily in the Barnett. Additionally, our focus on operational efficiencies, access to BKV-owned and third-party midstream systems, and proximity to natural gas demand markets along the Gulf Coast and Northeast corridor allow us to generate high margins.

As of December 31, 2022, our total acreage position was approximately 495,000 net acres, 99% of which was held by production. As of December 31, 2022, our net daily production (after giving effect to the Exxon Barnett Acquisition) averaged 871.9 MMcfe/d, consisting of approximately 79% natural gas and approximately 21% NGLs. As of December 31, 2022, our total proved reserves of 6,136 Bcfe had an estimated 7.3% year-over-year average base decline rate over the next 10 years. We have more than 10 years of core inventory remaining, with attractive returns, based on a 1 to 1.5 rigs per year pace, including 194 proved undeveloped, 162 probable and 137 possible horizontal locations, and 584 proved developed non-producing, 743 probable, and 234 possible refracture (“refrac”) candidates. Based on current commodity prices, the capital investment required to hold production flat year-over-year is less than approximately 35% of our Adjusted EBITDAX for the 2022 fiscal year. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See “*— Summary Historical and Unaudited Pro Forma Financial Information — Non-GAAP Financial Measures*” for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

We entered the Barnett in October 2020 with our acquisition of more than 289,000 net acres and 3,850 producing operated wells and related upstream assets (the “2020 Barnett Assets”) from Devon Energy Corporation (“Devon Energy”). On June 30, 2022, we further scaled our Barnett position by acquiring approximately 165,000 net acres, 2,100 operated wells and related upstream, midstream and other assets in the Exxon Barnett Acquisition. As of December 31, 2022, our Barnett acreage position was approximately 458,000 net acres, which is approximately 99% held by production. Our average daily Barnett production (after giving effect to the Exxon Barnett Acquisition) of approximately 732.7 MMcfe/d for the year ended December 31, 2022 consisted of 75% natural gas and 25% NGLs. We had an average working interest in our operated wells in the Barnett of approximately 96.2% as of December 31, 2022 and an Effective NRI in the Barnett of approximately 80.25%.

We are the largest natural gas producer by gross operated volume in the Barnett. Based on information published by the Texas Railroad Commission (“TRRC”), the chart below illustrates our gross operated production volumes in the Barnett (including the Exxon Barnett Acquisition), which represent approximately 27% of the total Barnett production, and nearly 75% greater than that of the next largest producer in the Barnett for the month of October 2022.



We entered NEPA in 2016 and have subsequently scaled our position through 12 acquisitions. As of December 31, 2022, our acreage position was approximately 37,000 net acres, which is approximately 94% held by production. Our average net daily production of 139.2 MMcfe/d for the year ended December 31, 2022 consisted entirely of natural gas. We had an average working interest in our operated wells in NEPA of 88%, as of December 31, 2022.

Natural Gas Midstream

Through our ownership in midstream systems, we are engaged in the gathering, processing and transportation of natural gas (which we refer to as our natural gas midstream business) that supports our upstream assets and third-party producers in the Barnett and NEPA. Our midstream assets improve our overall corporate returns by enhancing our margins and lowering our break-even operating costs while allowing us to manage the timing, development and optimization of production of our upstream assets. In the Barnett, as of December 31, 2022, approximately 190 MMcf/d of our gross production (approximately 23% of our total gross Barnett production) was gathered and processed by our owned Barnett midstream system, which includes approximately 778 miles of gathering pipeline, 65 midstream compressors and one amine processing unit. Additionally, our owned Barnett midstream system has over 200 MMcf/d in unutilized pipeline and processing capacity, providing room to increase throughput (from our own production and for third-party volumes) while maintaining optimal operating pressure with limited additional capital investment required. We also believe we have ample dedicated capacity on third party midstream systems for our expected production and future development. In NEPA, as of December 31, 2022, we had an approximate 29.4% non-operated ownership interest in a midstream system, which is operated by subsidiaries of Repsol Oil & Gas (“Repsol”), with throughput of approximately 174 MMcf/d, and we separately own and operate approximately 16 miles of natural gas gathering pipelines, 14 miles of freshwater distribution pipelines and six gas compression units.

Power Generation

We have a 50% ownership interest in the BKV-BPP Power Joint Venture, which owns Temple I, a newly-constructed, modern combined cycle gas and steam turbine power plant located in the Electric Reliability Council of Texas (“ERCOT”) North Zone in Temple, Texas. The remaining 50% interest is owned by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu. Temple I has an annual average power generation capacity of 755 MW and delivers power to customers on the ERCOT power network in Texas. Temple I is among the most efficient generators supplying power to ERCOT, with a baseload design heat rate of approximately 6,950 Btu/kWh, which is well below the ERCOT Combined Cycle Gas Turbines (“CCGT”) average. Temple I’s modern technology enables it to respond to rapidly changing market signals in real time by minimizing congestion risk and ensuring the highest operational readiness during the time when electricity consumption peaks (in winter and summer), making it well-suited to serve the various needs of the ERCOT market. We expect our power generation assets will be synergistic with our base upstream business. In the near term, we will seek to establish midstream contracts that allow us to supply our own natural gas directly to Temple I and its firm intrastate natural gas storage service at the Bammel storage facility. Supplying our own natural gas to Temple I will reduce gas transportation costs and create reciprocal natural hedges for both businesses via vertical integration. Additionally, we leverage our existing organization to provide marketing, engineering, finance, accounting and other administrative services to the BKV-BPP Power Joint Venture for an annual fee plus expenses.

In addition, after receiving the necessary approvals from the Public Utility Commission of Texas (the “PUCT”) and ERCOT, the BKV-BPP Power Joint Venture recently launched a retail marketing business to sell electricity to commercial, industrial, and residential retail customers in Texas through its wholly owned subsidiary, BKV-BPP Retail, LLC (“BKV-BPP Retail”), under the brand name BKV Energy. Since its official launch in February 2023, BKV Energy has built a portfolio of over 5,200 customers and is licensed to serve throughout the deregulated portions of Texas. Moreover, we intend to develop our ability to provide a Scope 1, 2 and 3 carbon neutral gas product, which we refer to as Measured Net Zero (“MNZ”) gas, and we believe that the expansion of our presence in the retail power space, along with the synergistic and opportunistic growth of our upstream, midstream and power generation businesses, will provide our retail energy business the opportunity to offer end consumers household energy sourced from MNZ gas. For more information about the risks involved in our retail power business and efforts to market MNZ gas, see “*Risk Factors — Risks Related to Our Power Generation Business — Our long-term business plan involves the expansion of our retail power business and the development of opportunities to offer end consumers household energy sourced from a Scope 1, 2 and 3 carbon neutral gas product.*”

Carbon Capture, Utilization and Sequestration

Through our CCUS business, we aim to reduce man-made GHG emissions to the atmosphere by capturing CO_2 emitted in connection with natural gas activities, whether from our own operations or third- party operations, as well as from other energy and industrial sources. Our process involves capturing CO_2 before it is released into the atmosphere and then compressing the captured CO_2 and transporting it via pipeline to sites where it can be injected into Underground Injection Control (“UIC”) wells for secure geologic sequestration. Additionally, we have engaged Project Canary to measure, analyze and report the environmental attributes of the sequestration projects. Although we formally launched our CCUS business in March 2022 with the establishment of BKV dCarbon Ventures, we have been evaluating project opportunities and developing our CCUS business for approximately two years. The development of our CCUS business has progressed rapidly, supported by internal engineering, business development and regulatory professionals, along with academics and CCUS-focused partnerships. We believe that with a continued and timely execution of our business plans, and the receipt of external funding in 2023, we will begin generating positive CCUS net income via tax credits and other tax benefits in 2025. We expect to fund our CCUS business with a combination of cash flows from operations and funding from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified and described below.

We seek to execute CCUS projects with attractive standalone economics for high, medium and low CO_2 concentration streams that will sequester emissions from both our own operations and from third-party operations. As part of our “closed-loop” approach to our net zero emissions goal, we expect to apply the CO_2 emissions that are sequestered through our CCUS business to offset GHG emissions from our owned and operated upstream businesses. As a result, we expect our CCUS business to contribute to our goals to fully offset the Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025, and the Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s. We estimate that our owned and operated upstream Scope 1 and 2 annual emissions were approximately 1.7 Mtpy CO_2e as of December 31, 2022 and that our owned and operated upstream Scope 1, 2 and 3 annual emissions were approximately 15.32 Mtpy CO_2e as of December 31, 2022. See “— *Path to Net Zero*

Emissions" below for a description of how we estimate our Scope 1, 2 and 3 annual emissions and how we expect our CCUS business to contribute to the offset of those emissions.

In August 2022, we entered into a development agreement with Verde CO2, an independent carbon capture and sequestration developer and operator, to identify, evaluate and develop additional CCUS projects throughout the United States. We believe our agreement with Verde CO2 will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration. As of April 6, 2023, we have paid $17.3 million to Verde CO2 under the development agreement. We currently expect to invest up to $250.0 million over the next three years to fund efforts by BKVerde, a subsidiary of BKV dCarbon Ventures, to efficiently identify and evaluate feasible CCUS projects, and to execute on those projects.

Currently, we are pursuing twelve potential CCUS projects that we believe are commercially viable based on economics supported by enhanced Section 45Q tax credits and can be completed by the early 2030s. We anticipate that the completion of these or a combination of other comparable projects would enable us to achieve our Scope 1, 2 and 3 emissions goals. These twelve potential CCUS projects consist of a combination of projects being developed by BKV's internal CCUS team and projects being developed by Verde CO2. Under our development agreement with Verde CO2, Verde CO2 will develop and present projects to us for acceptance and assignment to BKVerde; however, we cannot guarantee that all projects currently in development by Verde CO2 will be accepted and assigned to BKVerde. See "— *Recent Developments — CCUS Project Development with Verde CO2*." Our projected timeline for commercial operations of these twelve projects by the early 2030s depends in part on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. Our timeline also depends on a regulatory environment that is favorable to our projects and their development. These twelve potential projects can be placed into four categories: (i) those that have reached FID, (ii) near-term NGP projects, (iii) near-term industrial projects, and (iv) projects under evaluation. Near-term projects are those that we anticipate will reach FID in either 2023 or 2024. We have achieved notable milestones with respect to several of the projects within the four categories, as more fully described below.

FID Projects

We have reached FID and entered into definitive agreements with respect to the Barnett Zero Project, and we have reached internal FID for the Cotton Cove Project. These two projects have a combined forecasted annual sequestration volume of approximately 255,000 metric tons per year of captured CO_2e by the end of 2024.

Barnett Zero Project. In June 2022, we reached FID and entered into a definitive agreement in connection with our first high concentration CCUS project in the Barnett with EnLink Midstream, LLC ("EnLink"). This CCUS project, which we refer to as the Barnett Zero Project, will separate CO_2 from substantially all of our EnLink-gathered natural gas production. In the Barnett Zero Project, EnLink will transport our natural gas produced in the Barnett to its natural gas processing plant in Bridgeport, Texas, where the CO_2 waste stream will be captured, compressed and then disposed of and sequestered via our nearby injection well. We expect the Barnett Zero Project to achieve an average sequestration rate of up to approximately 210,000 metric tons of CO_2e per year, with the first injection expected by December 2023. Following commencement of commercial operations of our project with EnLink, we intend to use this project as a prototype for modular NGP projects that can be repeated and quickly scaled.

Cotton Cove Project. On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of, and geologically sequester CO_2 generated as a byproduct of our natural gas production in the Barnett and will utilize our newly acquired BKV Midstream assets to do so. We have multiple company-owned pore space opportunities for CO_2 injection, and we estimate the Cotton Cove Project will geologically sequester up to approximately 45,000 metric tons of CO_2e per year. We currently estimate the total investment required by us for the Cotton Cove Project to be between approximately $14.0 and $24.0 million. We are targeting commencement of CO_2 sequestration activities by the first half of 2024, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects.

We are also seeking to expand the Barnett Zero and Cotton Cove Projects to pilot, and then scale, post-combustion carbon capture technology that would allow us to sequester up to an additional approximately 250,000 metric tons per year of captured CO_2e from low concentration emissions from within our BKV Midstream and/or EnLink's Bridgeport processing operations. As part of this process, we intend to utilize compressor waste heat to reduce energy requirements and cost.

NGP Projects

In addition to the Barnett Zero Project and the Cotton Cove Project, we have identified three potential NGP projects to sequester third-party emissions, which we expect to reach FID in either 2023 or 2024. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of at least approximately 970,000 metric tons per year of captured CO_2e.

A significant portion of the carbon capture infrastructure necessary to execute these potential NGP projects already exists, one of which is currently being developed by Verde CO2 under our development agreement with them. For another one of these projects, we have entered into a non-binding letter of intent to secure a pore space leasehold that would provide approximately 45 million metric tons of CO_2e sequestration capacity. Therefore, if approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2025. We expect that by the end of 2025, these three NGP projects will have initial individual annual sequestration volumes of approximately 70,000, 265,000 and 635,000 metric tons per year of captured CO_2e, respectively, and a combined annual aggregate sequestration volume of approximately 970,000 metric tons per year of captured CO_2e. In addition, we expect over time to submit permit applications to develop Class VI injection wells in order to expand the sequestration capacity of two of these NGP projects to gradually build up to a forecasted annual sequestration volume after 2025 for all three of these NGP projects of approximately 3.3 million metric tons per year of captured CO_2e.

We expect by the end of 2025 that the combined annual forecasted sequestration volume from these NGP projects, the Barnett Zero Project and the Cotton Cove Project (collectively having an annual forecasted sequestration volume of approximately 1.23 Mtpy CO2e), would be capable of offsetting annually more GHG emissions than our remaining Scope 1 and 2 annual emissions from our owned and operated upstream businesses after taking into account the expected GHG emissions reductions from our "Pad of the Future" program, reductions attributable to emissions monitoring and leak surveys and emissions offsets from the installation of solar power (such remaining emissions estimated to be approximately 0.70 Mtpy CO_2e). See "*— Path to Net Zero Emissions*." However, we have not secured external financing, reached FID or entered into definitive agreements for any of these three additional NGP projects. We may not complete all or any of these three additional NGP projects, the Barnett Zero Project or the Cotton Cove Project by December 31, 2025, in which case, we may consider alternatives to offset our Scope 1 and Scope 2 owned and operated upstream emissions (including the purchase of verified offset credits) but, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025 and Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s.

Industrial Projects

We are currently evaluating three potential medium to higher concentration industrial projects to sequester third-party emissions, which we anticipate will reach FID in either 2023 or 2024. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of approximately 16.7 million metric tons per year of captured CO_2e.

Two of the three projects are being developed by Verde CO2 under our development agreement with them. One of the three projects includes an agreement to acquire a carbon dioxide storage agreement covering approximately 20,000 acres of state-owned land and pore space leaseholds have been secured for the other two of these projects. We also anticipate that Class VI permit applications for each of these projects will be submitted during 2023. If each of these projects is approved at FID and we are able to secure sufficient external financing, and assuming definitive agreements are timely executed containing terms we believe are obtainable, we expect to initiate sequestration operations between 2025 and 2029.

Additional Projects

We are currently evaluating and have begun commercial discussions with respect to four additional CCUS projects that we anticipate may reach FID after 2024. If approved and implemented, these four projects would provide a combined forecasted annual sequestration volume of approximately 9.8 million metric tons per year of captured CO_2e.

If each of these projects is approved at FID and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect to begin sequestration operations between 2026 and 2029.

Our CCUS business of capturing and sequestering emissions from our operations and from operations of third parties is a critical component of our "closed-loop" approach to achieving our goal of net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s. We expect to continue to identify and evaluate additional CCUS projects and we believe that we will be able to complete a sufficient number of the above-described or other CCUS projects in order to meet our Scope 1, 2 and 3 emissions goals by the early 2030s. See "*— Path to Net Zero Emissions*" for a more detailed description of how we anticipate reaching our Scope 1, 2 and 3 emissions goals.

While the aggregate forecasted annual volume of CO_2e captured and sequestered from our twelve identified potential CCUS projects is approximately 30 million metric tons per year, which is more than our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream businesses, we do not anticipate achieving an aggregate yearly volume of sequestration of 30 million metric tons per year of captured CO_2e by the early 2030s. Furthermore, there can be no guarantee that we will be able to execute and complete any of the twelve identified CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2e sequestration to achieve our Scope 1, 2 and 3 emissions goals on the timelines we anticipate.

We estimate the aggregate investment required by us to fund a sufficient number of the identified potential CCUS projects in order to achieve our Scope 1, 2 and 3 emissions goals to be between approximately $1.3 billion and $1.8 billion over the next seven to ten years. We anticipate that some of these project costs will be borne by third-party investors in these projects, including emitters, landowners and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund the anticipated cost of these CCUS projects with a combination of cash flows from operations and up to 40% from external sources, which may include joint ventures, project-based equity partnerships and federal grants. We are able to moderate the capital required to fund our CCUS business, as our CCUS business model provides flexibility for us to selectively invest in only the sequestration component of a project or in the capture, transportation and sequestration components, depending on the scope of the project. Therefore, if sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline, which may result in an inability to achieve our Scope 1, 2 and 3 emissions goals on the timeline we anticipate.

Our CCUS business and all of our CCUS projects are in the early stages of development and while we have reached FID and entered into definitive agreements with respect to the Barnett Zero Project and reached internal FID for the Cotton Cove Project, we have not reached FID with respect to or entered into definitive agreements necessary to execute any of the other ten potential projects identified above. We may not be able to reach agreements on terms acceptable to us or achieve our projected timeline for commercial operations for these projects. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on certain financial and tax incentives provided by the U.S. federal government. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business.*"

To help us achieve our goal of becoming a leader in CCUS, we established a steering committee that includes two engineers renowned for their work in the development of CCUS projects: Dr. Paitoon (P.T.) Tontiwachwuthikul (Professor of Industrial & Process Systems Engineering & Fellow, Canadian Academy of Engineering) and Dr. Malcolm A. Wilson (Program Director, CO_2 Management, Office of Energy & Environment (OEE), Adjunct Professor of Engineering and Graduate Studies). These individuals are professors at the University of Regina, a leading carbon capture research institution, and each has been engaged in CCUS for over 30 years.

For more information on our CCUS business, see "*Business — Our Operations — Carbon Capture, Utilization and Sequestration*."

Path to Net Zero Emissions

We estimate that our owned and operated upstream Scope 1 and 2 annual emissions were approximately 1.70 Mtpy CO_2e as of December 31, 2022. This reflects a reduction of 0.5 Mtpy CO_2e from our estimated owned and operated upstream Scope 1 and Scope 2 annual emissions as of December 31, 2021 due to the implementation of "Pad of the Future" emissions reductions that began in the fourth quarter of 2021 and occurred throughout 2022. The 2022 estimate is also inclusive of the assets acquired in the Exxon Barnett Acquisition in June 2022.

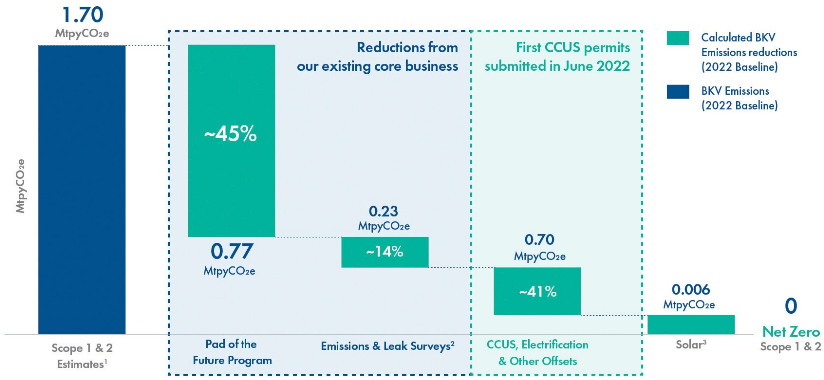
Our emissions estimates presented in this prospectus are based on information with respect to our owned and operated assets in the Barnett and NEPA through fiscal year 2022 and reported by BKV pursuant to the Subpart C and Subpart W, as applicable, requirements of the federal Clean Air Act GHG reporting program regulations of the EPA. These estimates fluctuate throughout the year and will be updated on an annual basis to reflect any changes in activity, inventory, production throughput, and emissions reduction retrofits or equipment modifications.

We estimate that our owned and operated upstream Scope 3 annual emissions were approximately 13.62 Mtpy CO_2e as of December 31, 2022. Our Scope 3 GHG emissions are currently estimated in accordance with IPIECA's "Sustainability reporting guidance for oil and gas industry," dated March 2020, specifically for Scope 3 emissions as estimated per Category 11 (Use of Sold Product). Scope 3 emissions estimated using source Category 11 represent the majority of Scope 3 emissions from our upstream operations with minor contributions from other source categories. Additionally, our estimated Scope 3 emissions calculations assume that all natural gas produced is combusted and does not account for other potential end use of natural gas. Scope 3 mass emissions are calculated using the Environmental Protection Agency's ("EPA") prescribed emissions factors for the speciated natural gas (methane and ethane) as well as NGLs assuming Y-grade NGLs. CO_2e emissions are estimated using AR4 Global Warming Potentials, similar to those used by the EPA. Our projected Scope 3 CO_2e annual emissions are estimated at an approximated year-end net production volume of 900 MMcfe/d, with an approximate split of 80% natural gas (95% methane and 5% ethane) and 20% NGLs. Our NGL constituents are estimated based on average constituent NGL barrel. Allocating the entire 900 MMcfe/d towards combustion as the end use, applying suitable combustion emission factors from the EPA, and using AR4 GWPs, Scope 3 annual emissions from our owned and operated upstream operations are estimated to be approximately 13.62 Mtpy CO_2e. We currently engage third party consultants to develop and review our Scope 3 emissions estimates.

The charts below reflect (i) our owned and operated upstream Scope 1 and 2 annual emissions estimates as of December 31, 2022, and (ii) our owned and operated upstream Scope 3 annual emissions estimates as of December 31, 2022, in each case, inclusive of the emissions generated by the assets acquired in the Exxon Barnett Acquisition. These two charts also reflect our intended path to net zero Scope 1 and 2 emissions by the end of 2025 and net zero Scope 1, 2 and 3 emissions by the early 2030s, in each case, for our owned and operated upstream businesses. As part of our "closed-loop" approach to our emissions goals, we intend to achieve these goals through our "Pad of the Future" emissions reductions, reductions attributable to emissions monitoring and leak surveys, emissions offsets from installing solar power and executing CCUS projects to sequester our and third-party emissions.

BKV's Planned Path to Net Zero (Scope 1 & 2): Barnett and NEPA Production

Based on total BKV upstream emission estimates in the Barnett and NEPA



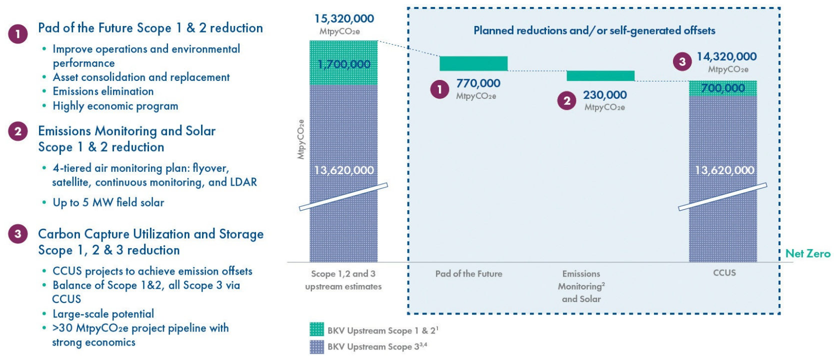
(1) Scope 1 and 2 calculated emissions are based on 830 MMscf/d production volume (net sales) for 2022 Subpart W in the Barnett and 144 MMscf/d production volume for 2022 Subpart W in NEPA.

(2) Emissions surveys to accomplish a one-to-two month leakage review period versus 12-month period which must have regulatory updates (current proposed OOOO.b,c) to include continuous flyover/satellite technology sensitivities.

(3) Installation of a 2.5 MW to 5 MW solar farm. We have obtained permits for 2.5 MW and are in the process of obtaining permits for the remaining 2.5 MW.

BKV's Planned Path to Net Zero (Scope 1, 2 & 3): Barnett and NEPA Production

Based on total BKV upstream emission estimates in the Barnett and NEPA



(1) Scope 1 and 2 calculated emissions are based on 830 MMscf/d production volume for 2022 Subpart W in the Barnett and 144 MMscf/d production volume for 2022 Subpart W in NEPA.

(2) Emissions surveys to accomplish a one-to-two month leakage review period versus 12-month period which must have regulatory updates (current proposed OOOO.b,c) to include continuous flyover/satellite technology sensitivities. Installation of a 2.5 MW to 5 MW solar farm. We have obtained permits for 2.5 MW and are in the process of obtaining permits for the remaining 2.5 MW.

(3) Scope 3 calculated emissions are based on an estimated net production rate of approximately 900 MMcfe/d (approximately 720 MMscf/d of natural gas and 31,000 Bbl/day of NGLs).

(4) Scope 3 calculated emissions are estimated assuming fuel-based usage of all produced natural gas and

NGLs. Approximately 58% of NGLs are assumed to be combusted for fuel while 100% of all natural gas sold is assumed to be combusted for fuel. Scope 3 emissions estimation methodology is therefore considered to be conservative.

Planned Path to Net Zero (Scope 1 and 2)

Pad of the Future. Our "Pad of the Future" program implements pad level design improvements to reduce pad level usage of natural gas, reduce GHG emissions, and maintain operational continuity. As of December 31, 2022, we had implemented elements of our "Pad of the Future" on approximately 2,500 of our existing wells, thereby eliminating an aggregate of approximately 0.38 Mtpy CO_2e in annual GHG emissions from commencement in the fourth quarter of 2021 through such date. Our estimated emissions reduction from year-end 2021 to year-end 2022 was primarily the result of our "Pad of the Future" program. These reductions are calculated by using our pneumatic and other pad inventories, and such emissions are factored to be eliminated once the system has been converted from natural gas supplied to compressed air or electric.

We expect to implement elements of our "Pad of the Future" program on more than 6,000 of our existing wells (more than 8,000 pneumatic devices and 2,000 pneumatic pumps) by the end of 2025 for an aggregate estimated cost of approximately $35 to $40 million. Once this expansion is completed, we expect to eliminate approximately 0.77 Mtpy CO_2e, or approximately 45%, of the currently estimated Scope 1 and 2 annual emissions from our owned and operated upstream businesses.

Emissions Monitoring and Solar. Our leak detection and repair emissions monitoring program involves continuous ground-based instrument monitoring, satellite-based monitoring, aerial flyovers, and on the ground leak detection and repair inspections. In addition, we expect to install a 2.5 MW to 5 MW solar farm, which is scheduled to begin generating power in 2024. We have obtained permits for 2.5 MW and are in the process of obtaining permits for the remaining 2.5 MW. For every 1,000 kilowatt-hours of electricity produced by an eligible solar facility, one SREC is awarded. For a solar facility to be credited with that SREC, the system must be certified and registered by state agencies. The solar farm is expected to generate enough SRECs, when combined with our leak detection and repair emissions monitoring program, to offset approximately 0.23 Mtpy CO_2e in GHG emissions from our owned and operated upstream businesses. Solar facilities may be subject to increasingly arduous regulatory requirements, including additional permitting requirements.

CCUS. Further, as discussed under "— *Carbon Capture, Utilization and Sequestration*" above, we believe that the Barnett Zero Project and the Cotton Cove Project, together with the three additional near-term NGP projects for the capture and sequestration of third-party emissions that we have identified, have a combined annual forecasted sequestration volume of approximately 1.23 Mtpy CO_2e. We believe that these projects are capable of offsetting by the end of 2025 more than the approximately 0.70 Mtpy CO_2e Scope 1 and 2 emissions from our owned and operated upstream businesses that we currently estimate will remain after taking into account the expected emissions reductions from our "Pad of the Future" program and emissions monitoring and leak surveys and emissions offsets from the installation of solar power. Although no definitive agreements have been entered into with respect to any of these additional NGP projects, we expect these projects to reach FID in either 2023 or 2024. A significant portion of the carbon capture infrastructure necessary to execute these potential NGP projects already exists and, as discussed above, we continue to accomplish important milestones consistent with our projected timeline. Therefore, if approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2025. If we are unable to complete each of these three projects before December 31, 2025, we may still reach our Scope 1 and 2 emissions goals with less than all of these projects completed as, individually, the annual forecasted sequestration volume by the end of 2025 of (i) the Barnett Zero Project is 0.21 Mtpy CO_2e, (ii) the Cotton Cove Project is 0.05 Mtpy CO_2e and (iii) the three near-term NGP projects is .07, 0.27 and 0.64 Mtpy CO_2e, respectively. However, we have not secured external funding, reached FID or entered into definitive agreements for any of these three additional NGP projects. We may not complete all or any of these three additional NGP projects, the Barnett Zero Project or the Cotton Cove Project by December 31, 2025, in which case, we may consider alternatives to offset our Scope 1 and Scope 2 owned and operated upstream emissions (including the purchase of verified offset credits or pursuing alternative CCUS projects) but, ultimately, we may not be able to achieve our goal of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025.

Planned Path to Net Zero (Scope 1, 2 and 3)

We also aspire to offset the Scope 3 emissions impact of our owned and operated upstream businesses by the early 2030s, which we estimate to be approximately 13.62 Mtpy CO_2e annually as of December 31, 2022, and our CCUS business of capturing and sequestering our and third-party emissions is a critical component to achieving this net zero goal. This aspiration to offset the Scope 3 emissions of our owned and operated upstream businesses by the early 2030s is limited to our Category 11 (Use of Sold Product) emissions. As discussed in "— *Carbon Capture, Utilization and Sequestration*," above, we have identified twelve potential CCUS projects that we believe are commercially viable that we estimate would have a combined forecasted annual volume of carbon capture and sequestration of approximately 30 Mtpy CO_2e (which exceeds our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream businesses). This forecast of annual sequestration volume of our and third-party emissions includes all twelve of our identified CCUS projects, including the Barnett Zero Project, the Cotton Cove Project and the three potential near-term NGP projects described in *"— Planned Path to Net Zero (Scope 1 and 2)"* above. While we expect to pursue a sufficient number of CCUS projects to achieve our Scope 3 emissions goal, we do not anticipate achieving an aggregate yearly volume of sequestration of 30 million metric tons per year of captured CO_2e before the early 2030s.

Large scale CCUS projects are subject to numerous risks and uncertainties, including securing third-party financing, reaching definitive agreements with third parties and obtaining necessary permits and other regulatory approvals, and we may be unable to execute on some or all of these projects, including the projects for which we have reached FID, on the timeline we anticipate, on terms acceptable to us or at all. There can be no guarantee that we will be able to execute and complete any of these identified CCUS projects and there can be no guarantee that we will be able to achieve our net zero Scope 1, 2 and 3 emissions goals. The projected timeline for commercial operations of our CCUS projects depends in part on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. If sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline. If we are not able to complete CCUS projects having a sufficient forecasted volume of carbon capture to offset our Scope 1, 2 and 3 annual emissions on the timeline and upon terms that we believe are obtainable, we may not be able to achieve our goal of net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s.

In addition, our path to net zero does not address GHG emissions from other business operations, including our midstream, power or CCUS business operations, but solely GHG emissions relating to our owned and operated upstream businesses. Although we believe our current path to net zero will be sufficient to reduce emissions related to our existing owned and operated upstream businesses, the future growth of our natural gas production assets will result in additional CO_2e emissions. We believe our approach to reducing the emissions from our owned and operated upstream operations is repeatable and scalable. Through continued investment and expansion of our "Pad of the Future" program, our emissions and leak surveys as well as additional CCUS and solar projects, we believe will be able to offset any such additional emissions from our owned and operated upstream businesses resulting from our continued growth.

Business Strategy

Our strategy is to create value for our stockholders by managing and growing our integrated asset base and focusing on our net zero objectives. Our strategy has the following principal elements:

- **Deliver robust returns to stockholders.** We intend to prioritize delivering strong returns to our stockholders through our dividend policy and focus on creating stockholder value. See "*Dividend Policy*." We believe our operational expertise in successfully drilling and refracturing wells, acquiring and integrating assets purchased at attractive valuations and maintaining financial discipline will underpin our ability to meet our stockholder return goals. Our integrated businesses and natural gas-weighted, low-decline PDP reserves collectively reduce our downside risk while providing asymmetric upside returns from the confluence of commodity price uplift potential, operational improvement and development opportunities, and future accretive acquisition opportunities. The payment of any future dividends on our common stock will be at the discretion of our board of directors and may vary significantly from quarter to quarter and may be zero. Any determination to pay dividends and the amount of any such dividends will depend on, among other factors, the restrictions under our Term Loan Credit Agreement and the Revolving Credit Agreement, as described under "*Dividend Policy*." See "*Risk Factors — Risks Related to the Offering and Our Common Stock*."

- **Optimize the value of our core businesses.** We utilize technology and data analysis to enhance our assets and operations, which we believe improves operational efficiencies, reduces our emissions and helps us realize our operational and financial goals as we continue to scale our business. For example, our "Pad of the Future" program, which includes conversion of natural gas-powered instrument pneumatics to compressed air power instruments on existing pads, combined with emission and leak surveys, is expected to eliminate or reduce approximately 1.15 Mtpy CO_2e of our annual GHG emissions by the end of 2025. Our "Pad of the Future" application also improves pad efficiencies and operating revenue. As of the year ended December 31, 2022, employing technology and operational excellence, we reduced our lease operating costs in the Barnett (excluding the 2022 Barnett Assets) by 4% based on the last 12-month rolling average as compared to the 10-month period of our ownership of the 2020 Barnett Assets in 2020, prior to BKV assuming operatorship, and in NEPA, we reduced our lease operating costs by 25% since January 2019, based on 12-month rolling average for this time period compared to the prior operatorship 12-month rolling average ending in January 2019. These lease operating cost reductions in the Barnett and NEPA include absorbing cost increases of 13% due to inflation. Additionally, our refrac and long lateral drill programs have allowed us to organically grow our reserves base. As of December 31, 2022, our Barnett refrac program has added 643 Bcfe of proved reserves since its inception in early 2021, as well as an estimated 520 Bcfe of probable reserves and 133 Bcfe of possible reserves. As of December 31, 2022, our Barnett refrac program has an average of $0.79/Mcfe in finding and development costs with respect to proved reserves. This refrac program employs specifically designed perforating technology and a suite of innovative refrac techniques, as well as advanced refrac designs and diversion methods to maximize reserve recovery and economics from legacy Barnett wells. Our Barnett new well drilling program has added 1.0 Tcfe of proved reserves since our entry into the Barnett, with a total estimate of approximately 677 Bcfe of probable reserves and 267 Bcfe of possible reserves. By combining our reserves into a growing asset base with vertically integrated components, we believe we can enhance margins and create a "closed loop" business that reduces Scope 1 and 2 emissions from our owned and operated upstream businesses and captures margin across the value chain. Estimates of probable and possible reserves are inherently imprecise and are more uncertain than proved reserves but have not been adjusted for risk due to that uncertainty, and therefore they may not be comparable with each other and should not be summed either together or with estimates of proved reserves. For more information regarding the presentation of probable and possible reserves, see "*Business — Preparation of Reserves Estimates and Internal Controls.*"

- **Grow through opportunistic, synergistic acquisitions.** A significant element of our business strategy is gaining scale through accretive acquisitions. We have a track record of growth through acquisitions, which we believe have been at attractive valuations. Since 2016, we have completed 19 acquisitions and two CCUS partnerships, resulting in greater than a 100% compound annual growth rate of Adjusted EBITDAX as of December 31, 2022. We believe our business model, management team experience and application of technology enable us to quickly and efficiently integrate additional upstream, midstream and power assets into our business.

- **Maintain a disciplined financial strategy.** We believe we can execute on our business plan and grow our business while continuing to generate substantial Adjusted Free Cash Flow. We target a Maintenance Reinvestment Rate of less than 30% and an Upstream Reinvestment Rate of less than 40%. We are focused on our goal of maintaining a conservative financial profile, with a long-term leverage target of less than 1.0x Total Net Leverage Ratio. Although we may allow our leverage ratio to exceed our target in connection with a strategic acquisition, we would seek to return our leverage level to below 1.0x as soon as reasonably possible thereafter through Adjusted Free Cash Flow and, if needed, reduced activity levels. To support the generation of future Adjusted Free Cash Flow, we have a policy of hedging approximately 25% to 60% of our production volumes over a given

12 to 24-month period. We believe our capital efficient project inventory, low-decline natural gas production and multiple, integrated business lines will provide consistent returns through varying business cycles. We intend to apply our cash flows to manage our indebtedness in line with our leverage target, fund our capital expenditure program, enhance stockholder value and execute opportunistic acquisitions across our four business lines. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See "—*Summary Historical and Unaudited Pro Forma Financial Information — Non-GAAP Financial Measures*" for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

- **Focus on our net zero objectives.** We seek to apply our integrated business model, CCUS projects, and carbon-negative initiatives to realize Scope 1 and 2 net zero upstream owned and operated emissions by the end of 2025. We believe we can achieve this through reductions in and offsets to our upstream emissions from our "Pad of the Future" emissions reductions program and emissions monitoring and leak surveys, installing solar power and executing CCUS projects. We believe that carbon emissions within the United States can be reduced substantially through carbon capture on natural gas production, power plants, processing facilities and other energy and industrial infrastructure. As such, in addition to lowering emissions in our owned and operated upstream businesses, CCUS for third parties has become a core focus of our business plan. We expect our CCUS projects to represent a meaningful portion of our budgeted capital expenditures going forward as we advance our long-term goal of offsetting Scope 3 emissions from our owned and operated upstream businesses.
- **Encourage innovation.** Our distinctive culture encourages innovation with a value-driven focus that feeds into our competitive advantage. For example, our emphasis on the efficient application of modern technology led to the development of our "Pad of the Future" program, our advancements in Barnett refracs and other operational improvements. We intend to continue to develop, retain and add to our already talented, experienced and forward-thinking employees. Our unified team and mantra of "Being a force for good" underpin our core values and provides us with confidence in our ability to successfully manage and grow our business.

Competitive Strengths

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

- **Integrated asset base well positioned for sustainable growth.** Our upstream, midstream and power asset bases reside in geographically concentrated areas with numerous asset acquisition opportunities in close proximity. Our proven ability to successfully negotiate, close and integrate these acquisition opportunities quickly and cost effectively will allow us to continue to grow our portfolio of assets synergistically. We believe that scale and the continued application of technological developments and operational excellence, combined with stable, low-decline production profiles, will continue to generate significant capital efficient development opportunities in the Barnett and NEPA.
- **High quality, low decline assets serving key demand markets.** Through a series of accretive acquisitions, we have established an extensive and largely contiguous acreage position in two key markets, the Barnett and NEPA. Our Barnett assets cover approximately 458,000 net acres, with an approximately 80.25% Effective NRI, and are located in close proximity to key Gulf Coast industrial and LNG demand centers. Our NEPA assets consist of 37,000 net acres in one of the most prolific parts of the Marcellus Shale and are located within less than 200 miles to key demand markets in the U.S. Northeast. We believe the geologic, operational and engineering risks associated with our leasehold acreage have been significantly mitigated through historical development activity. Our PDP reserves had an estimated 7.3% year-over-year average base decline rate over the next 10 years as of December 31, 2022. Additionally, we have an inventory of over 10 years of refrac and new drill locations within our core acreage that give us the flexibility to maintain or slightly grow current production levels, depending on the commodity cycle.
- **Lower emissions energy production.** We are focused on achieving Scope 1 and 2 net zero emissions from our owned and operated upstream businesses by the end of 2025. We believe we have a comprehensive ESG program, which is overseen and directed by an executive ESG steering committee.

In 2021, we certified our entire NEPA production and, in 2022, we certified a portion of our Barnett production and, in each case, achieved a Gold rating with Project Canary's TrustWell environmental assessment (Project Canary is an environmental certification and ESG data company). This is the second highest rating a company can receive for its production, qualifying the certified portion of our natural gas production as Responsibly Sourced Gas ("RSG"), or gas that is considered to be less carbon-intensive due to the way it was produced. In addition, we intend to advance the market for our produced gas beyond RSG and its current certification towards a Scope 1, 2 and 3 carbon-neutral natural gas product, which we refer to as Measured Net-Zero ("MNZ") gas. MNZ gas would be achieved by offsetting the estimated emissions associated with the production, gathering, and boosting of our RSG as well as the estimated emissions from transmission (and distribution, if applicable) of our sold gas through our CCUS projects as described in "—*Path to Net Zero Emissions*," with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We believe MNZ gas provides a fully decarbonized, certified, and qualified fuel that is a differentiated and premium product. We expect that both RSG and MNZ could command a premium in the marketplace and we have already executed a letter of intent with a potential buyer for the sale of our anticipated MNZ gas. Additionally, we have a plan to achieve net zero Scope 1 and 2 owned and operated upstream emissions by the end of 2025 based on our "Pad of the Future" program, emissions monitoring and leak surveys, installing solar power and executing CCUS projects. However, if we are not able to complete CCUS projects having sufficient sequestration volumes of CO_2 on this timeline, we may consider alternatives to offset our Scope 1 and Scope 2 emissions (including the purchase of verified offset credits) but, ultimately, we may not be able to achieve this goal or produce MNZ gas.

- **Efficient use of capital.** Our deep, high-graded inventory of refrac opportunities coupled with our inventory of new drill locations allow us to create meaningful additional cash flow with comparatively modest additional capital investments. We utilize operational improvements such as operational process and procurement efficiencies, use of existing field infrastructure, innovative and cost-effective refrac techniques and designs (including diversion methods), drilling long laterals in the Barnett, and optimizing available midstream capacity to further maximize our capital efficiency. Through our midstream, power and CCUS business lines, we are capturing margin across the value chain.
- **Well capitalized and conservative balance sheet.** As of December 31, 2022, we had a Total Net Leverage Ratio of 1.00x. Following the completion of this offering, we intend to continue to maintain a strong balance sheet and fund our upstream, midstream and power operations predominantly with internally generated cash flows. We believe that the low decline, predictable nature of our upstream production profile, combined with our hedging plan and reinvestment rate targets, will allow us to successfully meet our leverage goals.
- **High caliber and proven management team.** We maintain a highly experienced and knowledgeable management team with an average of over 25 years of experience among our senior management team. Our leadership team has significant experience managing integrated energy and power assets for large-scale enterprises, including companies such as PTT Exploration and Production Public Company Limited ("PTT Exploration") and BP p.l.c. ("BP"). Furthermore, our sponsor, Banpu, one of Asia Pacific's largest integrated energy companies, provides us with unique and valuable insights into optimizing our integrated energy business.

Recent Developments

Barnett Zero CCUS Project with EnLink

On June 8, 2022, BKV dCarbon Ventures and EnLink reached FID to develop our first high concentration CCUS project and entered into a definitive agreement to dispose of, and geologically sequester, CO_2 generated as a byproduct of the production of our natural gas in the Barnett. This CCUS project, which we refer to as the Barnett Zero Project, will separate CO_2 from substantially all of our EnLink-gathered natural gas production, which we expect to achieve an average sequestration rate of up to approximately 210,000 metric tons of CO_2e per year. We estimate the total investment required by us for the Barnett Zero Project to be between $29.0 and $34.0 million. We are targeting commencement of CO_2 sequestration activities by December 2023, subject to our ability to secure all required permits, at which point we expect this project will be one of the first permanent commercial CO_2 disposal and sequestration projects to come online in the United States.

Exxon Barnett Acquisition

On June 30, 2022, we closed the acquisition (the "Exxon Barnett Acquisition") of natural gas upstream and associated midstream infrastructure in the Barnett from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation, for a total purchase price of $750.0 million, plus additional contingent consideration of up to $50.0 million depending on future natural gas prices. Pursuant to the Exxon Barnett Acquisition, we acquired approximately 165,000 total net acres in the State of Texas that are approximately 99% held by production and located primarily in Tarrant, Johnson and Parker counties, with additional smaller positions in Jack, Wise, Denton, Erath, Hood and Ellis counties (our "2022 Barnett Assets"). These upstream assets include low decline wells, ideal for delivering consistent cash flow, and high average working interests of approximately 94% in over 2,100 operated wells. The Exxon Barnett Acquisition also included approximately 778 miles of gathering pipelines and compression and processing midstream infrastructure with, as of December 31, 2022, over 450 MMcf/d of throughput capacity and approximately 26 MMcf/d of third-party production being gathered on the system. In connection with the Exxon Barnett Acquisition, we entered into the Term Loan Credit Agreement (as defined herein) with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent. The Term Loan Credit Agreement includes up to $600.0 million of commitments for term loans to be used solely to fund a portion of the purchase price for the Exxon Barnett Acquisition and other costs and expenses associated with the acquisition. As of April 13, 2023, there was $570.0 million in aggregate principal amount outstanding under the Term Loan Credit Agreement. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Term Loan Credit Agreement*" for more information.

CCUS Project Development with Verde CO2

On August 22, 2022, we entered into a development agreement with Verde CO2 to identify, evaluate and develop CCUS projects throughout the United States. We believe our agreement with Verde CO2 will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration. Pursuant to the development agreement, Verde CO2 will be responsible for the sourcing, development, performance and ongoing management of such CCUS projects and BKV dCarbon Ventures will provide funding for such projects. As of April 6, 2023, we have paid $17.3 million to Verde CO2 under the development agreement, and we expect to invest up to $250.0 million over the next three years to fund efforts by BKVerde, a subsidiary of BKV dCarbon Ventures, to efficiently identify and evaluate feasible CCUS projects, and to execute on those projects. We expect to fund BKVerde through BKV's cash flow from operations but may also obtain funding from external sources.

Revolving Credit Agreement

On August 24, 2022, we entered into a Revolving Credit Agreement (as amended by that certain First Amendment to Revolving Credit Agreement dated as of November 11, 2022, the "Revolving Credit Agreement") with Bangkok Bank Public Company Limited (New York Branch), as the administrative agent and sole initial lender. The Revolving Credit Agreement includes $100.0 million of commitments for unsecured revolving loans used for short-term working capital and operating needs. As of April 13, 2023, no amount was outstanding under the Revolving Credit Agreement. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations —Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Revolving Credit Agreement*" for more additional information regarding the Revolving Credit Agreement.

Cotton Cove CCUS Project

On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of, and geologically sequester CO_2 generated as a byproduct of our natural gas production in the

Barnett and will utilize our newly acquired BKV Midstream assets to do so. We have multiple company-owned pore space opportunities for CO_2 injection and we estimate the Cotton Cove Project will geologically sequester up to approximately 45,000 metric tons of CO_2e per year. We currently estimate the total investment required by us for the Cotton Cove Project to be between approximately $14.0 and $24.0 million. We are targeting commencement of CO_2 sequestration activities by the first half of 2024, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects under evaluation as described in "*Business — Our Operations — Carbon Capture, Utilization and Sequestration.*"

Letter of Intent with EEMNA

On November 11, 2022, we entered into a non-binding letter of intent with ENGIE Energy Marking NA, Inc ("EEMNA") to build a framework for verifiable environmental attributes with the use of carbon credits applied to natural gas energy. Under this framework, we intend to measure, reduce and verify emissions using operational technologies, such as continuous emissions monitoring. In addition, we intend to advance our production of RSG towards a fully carbon-neutral natural gas production which we refer to as Measured Net-Zero ("MNZ") gas. MNZ gas would be achieved by offsetting the estimated emissions associated with the production, gathering and boosting of our RSG as well as the estimated emissions from transmission (and distribution, if applicable) of our sold gas through our CCUS projects, with the requisite volume of offsetting environmental attributes being third-party certified. We believe MNZ provides a fully decarbonized, certified, and qualified fuel that is a differentiated and premium product attractive to LNG buyers, gas utilities, power utilities or other end-users. Project Canary or another environmental certification and ESG data company will reconcile sensing technologies and measure, analyze, and report the environmental attributes of the sequestrated carbon to support the MNZ gas. Under the letter of intent, we anticipate eventually selling MNZ gas to EEMNA for marketing to end-users.

Corporate Values, Management Team and Sponsor

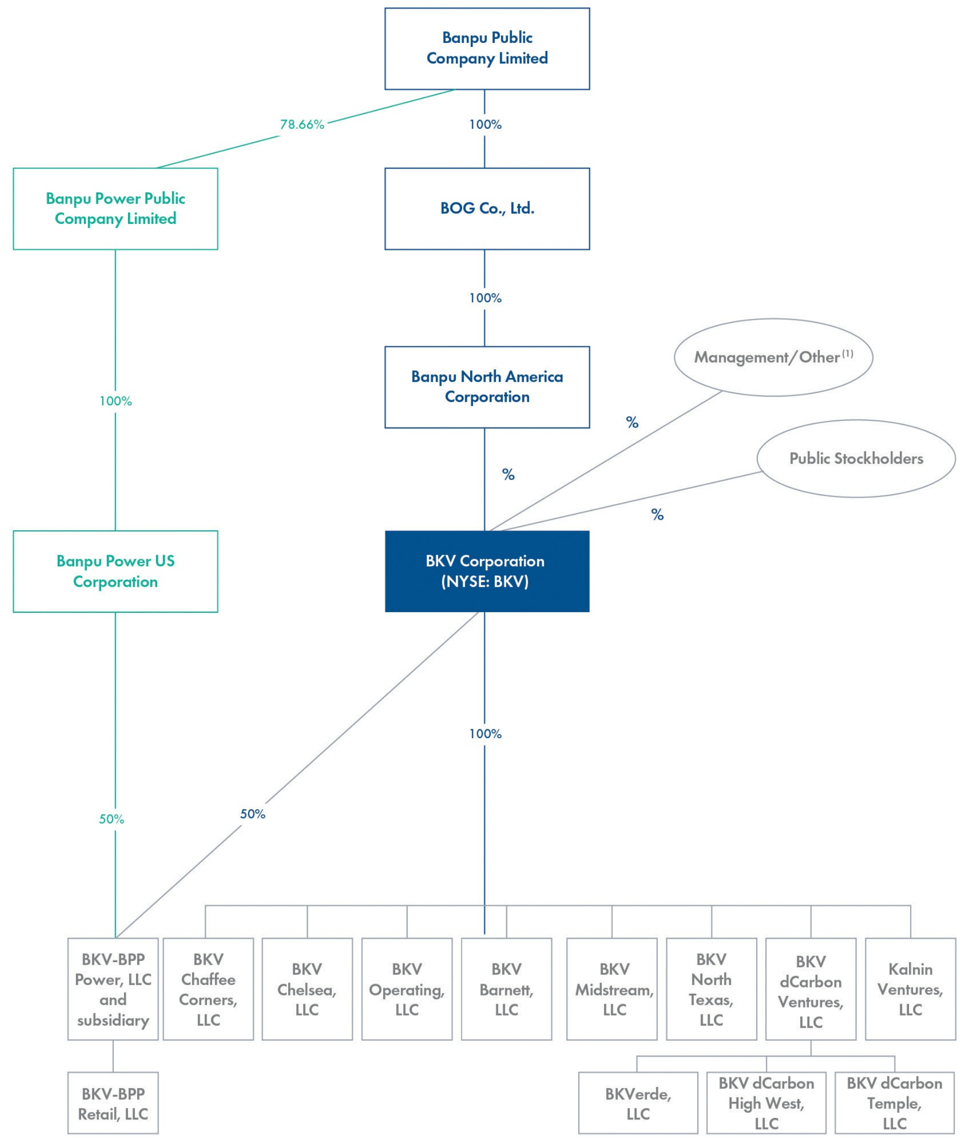
The following corporate values underpin our corporate culture and decision-making: Deliver on Promises, Have Grit, Embrace Change, Show Courage, Solve Problems, Do Good and Be One BKV.

Our management team is led by our Chief Executive Officer and founder, Christopher P. Kalnin, who has approximately 22 years of experience in exploration and production ("E&P") (PTT Exploration & Production), management consulting (McKinsey & Company) and finance (Credit Suisse First Boston). Eric Jacobsen serves as our Chief Operating Officer with over 28 years of energy operational experience, including 11 years of experience in shale, 16 years of experience at BP and its predecessors and six years of experience at Noble Energy, Inc. John Jimenez serves as our Chief Financial Officer with over 30 years of international energy experience working with BP and Reliance Industries Limited.

BNAC, our majority stockholder, is an indirect, wholly owned subsidiary of Banpu, our ultimate parent company. Banpu is a multi-billion U.S. dollar market cap energy company publicly traded in Thailand. With nearly four decades of experience in business operations covering 10 countries across the Pacific Rim region and the United States, Banpu is an international versatile energy provider committed to its Greener & Smarter strategy, which prioritizes environmentally sustainable businesses and leverages smart technologies and innovations. Upon completion of this offering, Banpu will beneficially own approximately   % of our common stock (or approximately   % if the underwriters exercise in full their option to purchase additional shares of our common stock). Banpu has informed us that although it may reduce a portion of its ownership position over time, it intends to remain a long-term stockholder and supporter of BKV. If, after this initial public offering, Banpu and its wholly owned subsidiaries cease to own at least 51% of our equity interests, or if they allow any lien to exist on our equity interests that they own, such event will be an event of default under the Term Loan Credit Agreement and the Revolving Credit Agreement. See "*Risk Factors — Risks Related to Our Relationship with Banpu and its Affiliates*."

Our Structure

The chart below displays a summary of our ownership structure after giving effect to this offering.



(1) Consists of management, directors and other employee and non-employee stockholders.

The information in the chart above does not include 10,000,000 additional shares of our common stock reserved for future awards pursuant to the BKV Corporation 2022 Equity and Incentive Compensation Plan (the “2022 Plan”), including shares of common stock that may be issued upon vesting of equity awards that we expect to be granted in connection with this offering, and 1,000,000 shares of our common stock available for purchase by employees pursuant to the BKV Corporation Employee Stock Purchase Plan (the "ESPP").

Implications of Being an Emerging Growth Company

We qualify as an "emerging growth company" as defined in Section 2(a)(19) of the Securities Act of 1933, as amended (the "Securities Act"), including as modified by the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). As a result, for so long as we qualify as an emerging growth company, we are eligible to take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies. These exemptions include:

- being permitted to present only two years of audited financial statements and only two years of related "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" in this prospectus;
- not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002, as amended (the "Sarbanes-Oxley Act");
- reduced disclosure obligations regarding executive compensation in our periodic reports, proxy statements and registration statements, including in this prospectus;
- not being required to comply with any new requirements adopted by the Public Company Accounting Oversight Board ("PCAOB") requiring 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; and
- exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved.

We have elected to take advantage of certain of the reduced disclosure obligations in this prospectus. As a result, the information that we provide in this prospectus may be different than you might receive from other public reporting companies in which you hold equity interests.

Because our gross revenues for the year ended December 31, 2022 exceeded $1.235 billion, we will not qualify as an emerging growth company following the consummation of this offering.

Controlled Company

We have applied to list our common stock on the NYSE under the symbol "BKV." Upon completion of this offering, BNAC will hold approximately % of our total outstanding shares of common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares), comprising more than 50% of the voting power of our outstanding common stock. As a result, we will be a "controlled company" within the meaning of the corporate governance rules of the NYSE. As a "controlled company," we will be eligible to rely on exemptions from the obligation to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of our board of directors consist of independent directors;
- we have a corporate governance and nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These exemptions do not modify the independence requirements for our audit committee. As a controlled company, we will remain subject to the rules of the Sarbanes-Oxley Act and the NYSE that require us to have an audit committee composed entirely of independent directors. Under these rules, we must have at least one independent director on our audit committee by the date our common stock is listed on the NYSE, at least two independent directors on our audit committee within 90 days of the listing date, and at least three independent directors on our audit committee within one year of the listing date. We expect to have three independent directors upon the closing of this offering.

While BNAC continues to control more than 50% of the voting power of our outstanding common stock, we qualify for, and intend to rely on, these exemptions. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

If we cease to be a controlled company within the meaning of the applicable rules of the NYSE, we will be required to comply with these requirements after specified transition periods.

Contact Information

Our principal executive offices are located at 1200 17th Street, Suite 2100, Denver, Colorado 80202, and our telephone number at such address is (720) 375-9680. Our website address is *www.bkvcorp.com*. The contents of our website are not incorporated by reference herein and are not a part of, and shall not deemed to be a part of, this prospectus.

The Offering

Issuer	BKV Corporation, a Delaware corporation
Securities offered	Common stock, par value $0.01 per share ("common stock")
Common stock offered by us	shares (or shares if the underwriters exercise in full their option to purchase additional shares)
Underwriters' option to purchase additional shares	The underwriters have an option for a period of 30 days to purchase up to an additional shares of our common stock.
Common stock outstanding immediately after this offering	shares (or shares if the underwriters exercise in full their option to purchase additional shares)
Use of proceeds	We estimate that the net proceeds to us from the sale of our common stock in this offering, after deducting underwriting discounts and commissions and estimated offering expenses payable by us, will be approximately $ million (or approximately $ million if the underwriters exercise in full their option to purchase additional shares), based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus). Of the net proceeds we receive from the sale of our common stock in this offering, we intend to use approximately $ million to repay in full the loan under the $75 Million A&R Loan Agreement (as defined herein) with BNAC, $ million to make additional contingent consideration payments payable in connection with the Devon Barnett Acquisition and the remainder for other general corporate purposes, including to fund the expansion of our CCUS business. See "*Use of Proceeds.*"
Dividend policy	At or prior to the closing of this offering, our board of directors will adopt a written policy pursuant to which we intend to pay to stockholders, subject to the factors described herein, including the restrictions under the Term Loan Credit Agreement and the Revolving Credit Agreement, quarterly cash dividends and to consider the payment of additional special dividends from time to time. See "*Dividend Policy.*"
Voting rights	Each share of common stock will entitle the holder to one vote per share. Generally, matters to be voted on by stockholders must be approved by a majority of the votes entitled to be cast at a meeting by holders of all shares of common stock present in person or represented by proxy. In addition, pursuant to the stockholders' agreement to be entered into upon the completion of this offering between BNAC and us (our "Stockholders' Agreement"), for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that (i) from the completion of this offering until the first anniversary

	of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. See "*Management*," "*Principal Stockholders*," "*Description of Capital Stock*" and "*Certain Relationships and Related Party Transactions*" for additional information.
Risk factors	You should read the section of this prospectus titled "*Risk Factors*" and other information included in this prospectus for a discussion of factors to carefully consider before deciding to invest in shares of our common stock.
Controlled company	We will be a "controlled company" within the meaning of the corporate governance rules of the NYSE. Upon completion of this offering, BNAC will hold % of our common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares), comprising more than 50% of the voting power of our outstanding common stock. See "*Management — Controlled Company*."
Listing and stock exchange symbol	We have applied to list our common stock on the NYSE under the symbol "BKV."

The number of shares of common stock that will be outstanding immediately after the completion of this offering is based on shares of our common stock to be issued pursuant to this offering (assuming the underwriters do not exercise their option to purchase additional shares), and excludes 10,000,000 additional shares of our common stock reserved for future awards pursuant to our 2022 Plan and 1,000,000 shares of our common stock available for purchase by employees pursuant to the our ESPP, which will become effective upon the completion of this offering.

Unless otherwise indicated and except for our historical consolidated financial statements and related notes included elsewhere in this prospectus, the information in this prospectus:

- assumes the execution of our Stockholders' Agreement, as further described under "*Certain Relationships and Related Party Transactions*";
- assumes the amendment and restatement of our existing certificate of incorporation and the amendment and restatement of our existing bylaws in connection with the consummation of the offering;
- assumes an initial public offering price of $ per share of common stock (the midpoint of the price range set forth on the cover page of this prospectus); and
- assumes that the underwriters do not exercise their option to purchase additional shares of common stock.

Risk Factors Summary

Investing in our common stock involves risks, including those highlighted in the section titled "*Risk Factors*" immediately following this prospectus summary, of which you should be aware before making a decision to invest in our common stock. These risks may offset our competitive strengths or have a negative effect on our strategy or operating activities, which could cause a decrease in the price of our common stock and a loss of all or part of your investment. These risks include, among others, the following:

Risks Related to Our Upstream Business and Industry

- the volatility of natural gas and NGL prices due to factors beyond our control;
- our reliance on a single third party for all of our natural gas marketing and another third party for substantially all of our natural gas and NGL midstream services with respect to the Barnett assets we acquired from Devon Energy;
- our reserve estimates are based on assumptions that may prove to be inaccurate;
- our ability to find or acquire additional natural gas and NGL reserves that are economically recoverable, including development of our proved undeveloped reserves and associated capital expenditures;
- uncertainties in evaluating the expected benefits and potential liabilities of recoverable reserves;
- risks and uncertainties related to drilling operations, which are high-risk and operationally complex;
- the availability or cost of water, equipment, supplies, personnel and oilfield services;
- our limited control over activities on properties we do not operate;

Risks Related to Our Power Generation Business

- the operation of our power generation business through a joint venture which we do not control;
- risks and hazards related to the operation or maintenance of electric generation facilities;
- the lack of long-term power sales agreements for Temple I;
- our ability to fulfill our business plan to expand our retail power business;
- the disruption of the fuel supplies necessary to generate power at Temple I;

Risks Related to Our CCUS Business

- our ability to successfully pursue and develop our CCUS business, the associated material capital investments and any changes to financial and tax incentives;

Risks Related to Our Midstream Business

- risks and hazards related to midstream operations as complex activities;
- our dependence on our natural gas midstream system for the gathering and processing of our natural gas production;

Risks Related to Our Business Generally

- the geographical concentration of substantially all of our oil and gas and midstream properties;
- the effect of a deterioration in general economic, business or industry conditions and COVID-19 (including any variants thereof, “COVID-19”);
- our ability to achieve our near term and long term net zero goals on our anticipated time frame;
- our ability to generate cash flow to meet our debt obligations or fund our other liquidity needs;
- events of default if we are unable to comply with restrictions in our debt agreements (including if Banpu and its wholly owned subsidiaries cease to own at least 51% of our equity interests or allow any lien to exist on our equity interests that they own);
- risks related to our debt and debt agreements and hedging arrangements that expose us to risk of financial losses and counterparty credit risk;
- our dependence, as a holding company, on our subsidiaries and our joint venture for cash;

- operating hazards that could result in substantial losses or liabilities for which we may not have adequate insurance coverage;
- our ability to make accretive acquisitions or successfully integrate acquired businesses or assets;
- our substantial capital requirements and our ability to obtain financing or fund working capital needs;
- the intense competition in the energy industry and our ability to compete with other companies;
- cybersecurity or physical security threats or disruptions or loss of our information systems;
- increased activism and negative investor sentiment regarding upstream activities and companies;
- the loss of our executive officers and technical personnel and our ability to retain technical personnel;

Risks Related to Environmental, Legal Compliance and Regulatory Matters

- complex laws, regulations and initiatives related to our operations and the use of hydraulic fracturing;
- the effect of increased attention to ESG matters and environmental conservation measures;
- reductions in demand for natural gas, NGL and oil due to energy conservation measures and technological advances;
- risks related to climate change, including transitional, legal, political, financial and physical risks;
- significant costs and liabilities related to federal, state and local environmental, health and safety laws and regulations;
- potential tax law changes;
- complex and evolving laws and regulations regarding privacy and data protection;

Risks Related to Our Relationship with Banpu and its Affiliates

- the substantial influence of Banpu, our controlling stockholder, over us;
- our historical reliance on Banpu for capital investments to fund our business operations;
- we expect to be a “controlled company” within the meaning of the NYSE rules and, as a result, will qualify for and could rely on exemptions from certain corporate governance requirements;
- conflicts of interest between Banpu and us or our other stockholders or conflicts of interest of our directors as a result of their positions with, or ownership of common stock of, Banpu;

Risks Related to the Offering and Our Common Stock

- our actual operating results and activities could differ materially from our estimates;
- risks related to payment of dividends on our common stock, including the lack of sufficient available cash, the discretion of our board of directors, and restrictions in our debt agreements, with respect to payment of dividends and the impact of our dividend policy on our ability to grow;
- the costs of, and our ability to comply with, the requirements of being a public company;
- we have identified material weaknesses in our internal control over financial reporting;
- the lack of an existing market for our common stock;
- provisions in our governing documents and Delaware law that could discourage acquisition bids or merger proposals; and
- future sales of our common stock in the public market, or the perception that such sales may occur, could reduce our stock price.

Summary Historical and Unaudited Pro Forma Financial Information

The following table shows our summary historical consolidated financial information and summary unaudited pro forma combined consolidated financial information for the periods and as of the dates indicated. The summary unaudited pro forma combined consolidated financial information presents the combination of our historical consolidated financial information, as adjusted to give effect to the Exxon Barnett Acquisition, the related financing under the Term Loan Credit Agreement and the $75 Million Loan Agreement (collectively, the "Transaction").

The summary historical consolidated financial information as of and for the years ended December 31, 2022 and 2021 was derived from our audited historical consolidated financial statements, included elsewhere in this prospectus.

The summary unaudited pro forma combined consolidated financial information was derived from the unaudited pro forma combined consolidated financial statements included elsewhere in this prospectus. The unaudited pro forma combined consolidated statements of operations data for the year ended December 31, 2022 has been prepared to give pro forma effect to the Transaction as if it had been consummated on January 1, 2022. This information is subject to, and gives effect to, the assumptions and adjustments described in the notes accompanying the unaudited pro forma combined consolidated financial statements included elsewhere in this prospectus. The pro forma financial information is provided for illustrative purposes only and is not intended to represent what our financial position or results of operations would have been had the Transaction occurred on the assumed date nor does it purport to project our future operating results or financial position following the Transaction. The summary pro forma financial information does not include pro forma balance sheet information because the Exxon Barnett Acquisition was consummated on June 30, 2022 and, therefore, the 2022 Barnett Assets and related financing are included in our historical balance sheet as of December 31, 2022, together with the related indebtedness under the Term Loan Credit Agreement and the $75 Million Loan Agreement.

The summary financial data is qualified in its entirety by, and should be read in conjunction with, "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and "*Unaudited Pro Forma Combined Consolidated Financial Statements*" included elsewhere in this prospectus, as well as our historical consolidated financial statements and related notes, the historical statements of revenues and direct operating expenses and related notes for the 2022 Barnett Assets acquired in the Exxon Barnett Acquisition and other financial information included in this prospectus. Historical and pro forma results are not necessarily indicative of results that may be expected for any future period.

	Year Ended December 31,			Pro Forma Year Ended December 31,
	2022	2021	2020	2022
	(in thousands, except per share amounts)			
Revenues and other operating income				
Natural gas sales	$1,310,339	$ 597,050	$101,758	*
NGL sales	311,542	225,135	11,952	*
Oil sales	11,866	7,560	1,333	*
Natural gas, NGL and oil sales	1,633,747	829,745	115,043	$ 1,852,979
Midstream revenues	12,676	6,917	7,458	$ 16,297
Derivative gains (losses), net	(629,701)	(383,847)	20,755	$ (629,701)
Marketing revenues	11,001	52,616	—	$ 11,001
Other	2,799	251	33	$ 3,047
Total revenues and other operating income	1,030,522	505,682	143,289	$ 1,253,623
Operating expenses				
Lease operating and workover	135,064	88,105	31,260	$ 193,240
Taxes other than income	114,668	45,650	5,151	$ 125,364
Gathering and transportation	208,758	173,587	—	$ 234,079
Depreciation, depletion, amortization and accretion(1)	118,909	92,277	87,343	$ 145,100

	Year Ended December 31, 2022	2021	2020	Pro Forma Year Ended December 31, 2022
	(in thousands, except per share amounts)			
General and administrative	148,559	85,740	29,442	$ 148,559
Total operating expenses	725,958	485,359	153,196	$ 846,342
Income (loss) from operations	304,564	20,323	(9,907)	$ 407,281
Other income and expense				
Bargain purchase gain	170,853	—	—	$ 170,853
Gain on settlement of litigation	16,866	—	—	$ 16,866
Gain (loss) on contingent consideration liabilities (2)	6,632	(194,968)	7,135	$ 6,632
Earnings from equity affiliate	8,493	910	—	$ 8,493
Interest income	1,143	8	121	$ 1,143
Interest expense	(26,322)	—	—	$ (47,396)
Interest expense, related party	(10,846)	(2,134)	(1,713)	$ (11,663)
Other income	1,411	872	—	$ 1,411
Income (loss) before income taxes	472,794	(174,989)	(4,364)	$ 553,620
Income tax benefit (expense)	(62,652)	40,526	(38,982)	$ (81,242)
Net income (loss) attributable to BKV Corporation	410,142	(134,463)	(43,346)	$ 472,378
Less accretion of preferred stock to redemption value	—	(3,745)	—	$ —
Less preferred stock dividends	—	(9,900)	(460)	$ —
Less deemed dividend on redemption of preferred stock	—	(22,606)	—	$ —
Net income (loss) attributable to common stockholders	410,142	(170,714)	(43,806)	$ 472,378
Net income (loss) per common share:				
Basic	$ 3.50	$ (1.46)	$ (0.42)	$ 4.03
Diluted	$ 3.31	$ (1.46)	$ (0.42)	$ 3.81
Weighted average number of common shares outstanding				
Basic	117,318	116,904	105,275	117,318
Diluted	123,980	116,904	105,275	123,980
Balance sheet information (at period end):				
Cash and cash equivalents	$ 153,128	$ 134,667	$ 17,445	**
Total natural gas properties, net	$2,209,518	$1,176,117	$1,169,297	**
Total assets	$2,702,573	$1,620,828	$1,342,492	**
Total liabilities	$1,506,649	$ 865,889	$ 262,424	**
Total mezzanine equity	$ 151,883	$ 83,847	$ 137,212	**
Total stockholders' equity	$1,044,041	$ 671,092	$ 942,856	**
Statement of cash flows information				
Net cash provided by (used in) operating activities	$ 349,194	$ 358,133	$ (7,405)	**
Net cash used in investing activities	$ (865,566)	$ (161,858)	$ (513,992)	**
Net cash provided by (used in) financing activities	$ 534,833	$ (79,053)	$ 442,723	**
Other financial data (unaudited) (3)				
Adjusted EBITDAX	$ 576,396	$ 281,024	$ 65,147	$ 704,975
Upstream Reinvestment Rate	43%	24%	16%	**
Adjusted Free Cash Flow	$ 123,913	$ 165,090	$ 56,604	**
Adjusted Free Cash Flow Margin	7%	19%	46%	**
Total Net Leverage Ratio (4)	1.00x	0.11x	0.10x	**

(1) Includes accretion of lease liabilities related to office space and compressor leases.

(2) Represents contingent consideration liabilities as of the dates set forth above accruing as an earnout obligation under the terms of our purchase agreement with Devon Energy for the purchase of our 2020 Barnett Assets. This contingent consideration is stated at fair value on our consolidated balance sheet, with changes in fair value recorded in the consolidated statement of operations.

(3) Adjusted EBITDAX and Adjusted Free Cash Flow are not financial measures calculated in accordance

with GAAP. See "— *Non-GAAP Financial Measures*" for how we define each of these measures and a reconciliation to the most directly comparable GAAP measures. In addition, we define Upstream Reinvestment Rate as total cash paid for upstream capital expenditures (excluding leasehold costs and acquisitions) as a percentage of Adjusted EBITDAX, and we define Adjusted Free Cash Flow Margin as the ratio of Adjusted Free Cash Flow to total revenues excluding derivative gains and losses. Total Net Leverage Ratio represents the ratio of total debt less cash and cash equivalents to Adjusted EBITDAX.

(4) Total Net Leverage Ratio is the ratio of our total debt less cash and cash equivalents to Adjusted EBITDAX.

* Revenues with respect to the 2022 Barnett Assets (as defined herein) for the years ended December 31, 2022 and 2021 are reported only on a consolidated basis. Accordingly, the unaudited pro forma combined consolidated natural gas, NGL and oil sales revenues are presented only in the aggregate. See "— *Unaudited Pro Forma Combined Consolidated Financial Statements*."

** The Exxon Barnett Acquisition was consummated on June 30, 2022, and, therefore, the 2022 Barnett Assets and related financing are included in the historical balance sheet of the Company as of December 31, 2022, and no pro forma balance sheet is presented. See "*Unaudited Pro Forma Combined Consolidated Financial Statements*."

Non-GAAP Financial Measures

Adjusted EBITDAX

We define Adjusted EBITDAX as net income (loss) attributable to BKV Corporation before (i) non-cash derivative gain (loss), (ii) depreciation, depletion, amortization and accretion, (iii) exploration and impairment expense, (iv) (loss) gain on contingent consideration liabilities, (v) interest expense, (vi) interest expense, related party, (vii) income tax benefit (expense), (viii) equity-based compensation expense, (ix) bargain purchase gains, (x) income from equity affiliates, (xi) early settlement of derivative contracts and (xii) other nonrecurring transactions. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by our management and external users of our consolidated financial statements, such as industry analysts, investors, lenders, rating agencies and others to more effectively evaluate our operating performance and results of operations from period to period and against our peers. We believe Adjusted EBITDAX is a useful performance measure because it allows us to effectively evaluate our operating performance and results of operations from period to period and against our peers, without regard to our financing methods, corporate form or capital structure.

We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX 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 EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) determined in accordance with GAAP. Certain items excluded from Adjusted EBITDAX 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 EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that our results will be unaffected by unusual or non-recurring items. Other companies, including other companies in our industry, may not use Adjusted EBITDAX or may calculate this measure differently than as presented in this prospectus, limiting its usefulness as a comparative measure.

The table below presents a reconciliation of Adjusted EBITDAX to net income, our most directly comparable GAAP financial measure for the periods indicated.

	Year Ended December 31, 2022	2021	2020	Pro Forma Year Ended December 31, 2022
	(in thousands)			(in thousands)
Net income (loss) attributable to BKV Corporation	$ 410,142	$(134,463)	$(43,346)	$ 472,378
Unrealized derivative (gains) losses	(58,815)	115,161	(10,329)	(58,815)
Forward month gas derivative settlement[1]	(9,013)	15,406	(5,489)	(9,013)
Depreciation, depletion, amortization, and accretion	130,038	98,833	90,191	155,900
Exploration and impairment expense	—	34	560	—
Change in contingent consideration liabilities	(6,632)	194,968	(7,135)	(6,632)
Interest expense	26,322	—	—	47,396
Interest expense, related party	10,846	2,134	1,713	11,663
Income tax expense (benefit)	62,652	(40,526)	38,982	81,242
Equity-based compensation expense	31,947	30,387	—	31,947
Bargain purchase gain	(170,853)	—	—	(170,853)
Income from equity affiliates	(8,493)	(910)	—	(8,493)
Early settlement of derivative contracts	158,255	—	—	158,255
Adjusted EBITDAX	$ 576,396	$ 281,024	$ 65,147	$ 704,975

(1) Natural gas derivative contracts settle and are realized in the month prior to the production covered by the contract. This adjustment removes the timing difference between the settlement date and the underlying production month that is hedged.

Adjusted Free Cash Flow

We define Adjusted Free Cash Flow as net cash provided by (used in) operating activities excluding changes in operating assets and liabilities, less total cash paid for capital expenditures and settlement of contingent consideration (excluding leasehold costs and acquisitions).

Adjusted Free Cash Flow is not a measure of net cash flow provided by or used in operating activities as determined by GAAP. Adjusted Free Cash Flow is a supplemental non-GAAP financial measure that is used by our management and other external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others to assess our ability to internally fund our capital program, service or incur additional debt and to pay dividends. We believe Adjusted Free Cash Flow is a useful liquidity measure because it allows us and others to compare cash flow provided by operating activities across periods and to assess our ability to internally fund our capital program (including acquisitions), to reduce leverage, fund acquisitions and pay dividends to our stockholders. Adjusted Free Cash Flow should not be considered as an alternative to, or more meaningful than, net income (loss) or net cash provided by (used in) operating activities determined in accordance with GAAP. Other companies, including other companies in our industry, may not use Adjusted Free Cash Flow or may calculate this measure differently than as presented in this prospectus, limiting its usefulness as a comparative measure.

The table below presents our reconciliation of Adjusted Free Cash Flow to net cash provided by (used in) operating activities, our most directly comparable GAAP financial measure for the periods indicated.

	Year Ended December 31,		
	2022	2021	2020
	(in thousands)		
Net cash provided by (used in) operating activities	$ 349,194	$ 358,133	$ (7,405)
Changes in operating assets and liabilities	22,816	(126,862)	74,536
Cash paid for capital expenditures (excluding leasehold costs and acquisitions)	(248,097)	(66,181)	(10,527)
Adjusted Free Cash Flow[(1)]	$ 123,913	$ 165,090	$ 56,604

(1) Adjusted Free Cash Flow for the year ended December 31, 2022, is $158.3 million lower due to realized losses resulting from the early termination of derivative contracts.

Summary Reserve, Production and Operating Data

Ryder Scott, our independent petroleum engineers, prepared estimates of our natural gas, NGL and oil reserves as of December 31, 2022, 2021 and 2020. These reserve estimates were prepared in accordance with the rules and regulations of the Securities and Exchange Commission (the "SEC") regarding oil and natural gas reserve reporting using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions ("SEC Pricing") (except for the table that provides our estimated reserves as of December 31, 2022 at "NYMEX strip pricing" using pricing based on NYMEX future prices as of market close on December 31, 2022). For more information about our reserve volumes and values, see "*Business — Preparation of Reserves Estimates and Internal Controls*" and Ryder Scott's summary reserve reports, which are filed as exhibits to the registration statement of which this prospectus forms a part.

The following table provides our estimated proved reserve, probable reserve and possible reserve information prepared by Ryder Scott as of December 31, 2022, 2021 and 2020 and PV-10 Value and the standardized measure of discounted future net cash flows (the "Standardized Measure") for each period. The increase in our proved reserves and the PV-10 Value of those reserves as of December 31, 2022 as compared to December 31, 2021 is primarily due to the Exxon Barnett Acquisition, our refrac and restimulation program, adding NGL rich locations to the drilling program and the increase in natural gas prices used in preparing the December 31, 2022 reserve information. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. In addition, estimates of probable and possible reserves are inherently imprecise and are more uncertain than proved reserves but have not been adjusted for risk due to that uncertainty, and therefore they may not be comparable with each other and should not be summed either together or with estimates of proved reserves. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves*."

Estimated Reserves at SEC Pricing(1)

	December 31,		
	2022	**2021**	**2020**
Estimated proved developed reserves:			
Natural gas (MMcf)	3,798,019	2,494,926	1,893,161
Producing	3,468,896	2,346,712	1,893,161
Non-producing.	329,123	148,214	—
Natural gas liquids (MBbls)	170,840	151,433	107,234
Producing	157,585	142,961	107,234
Non-producing.	13,255	8,472	—
Oil (MBbls)	1,111	867	723
Producing	1,111	876	723
Non-producing.	—	—	—
Total estimated proved developed reserves (MMcfe)	4,829,725	3,408,723	2,540,901
Producing	4,421,072	3,209,679	2,540,901
Non-producing.	408,653	199,044	0
Standardized Measure (millions)	$ 5,809	$ 2,119	$ 504
PV-10 (millions)(2)(3)	$ 7,389	$ 2,672	$ 552
Estimated proved undeveloped reserves:			
Natural gas (MMcf).	1,057,657	950,359	92,373

	December 31,		
	2022	2021	2020
Natural gas liquids (MBbls)	40,660	13,722	—
Oil (MBbls)	758	58	—
Total estimated proved undeveloped reserves (MMcfe)(4)(5)	1,306,165	1,033,040	92,373
Standardized Measure (millions)	$ 1,185	$ 294	$ 6
PV-10 (millions)(2)(6)	$ 1,566	$ 403	$ 9
Estimated total proved reserves:			
Natural gas (MMcf).	4,855,676	3,445,285	1,985,534
Natural gas liquids (MBbls)	211,500	165,155	107,234
Oil (MBbls)	1,869	925	723
Total estimated proved reserves (MMcfe)	6,135,890	4,441,763	2,633,274
Standardized Measure (millions)	$ 6,994	$ 2,413	$ 510
PV-10 (millions)(2)(7)	$ 8,955	$ 3,074	$ 561
Estimated probable developed reserves:			
Natural gas (MMcf).	367,081	—	—
Natural gas liquids (MBbls)	25,558	—	—
Oil (MBbls)	—	—	—
Total estimated probable developed reserves (MMcfe)	520,430	—	—
Standardized Measure (millions)	$ 281	—	—
PV-10 (millions)(2)(9)	$ 372	—	—
Estimated probable undeveloped reserves:			
Natural gas (MMcf).	572,425	522,442	61,884
Natural gas liquids (MBbls)	39,319	31,227	—
Oil (MBbls)	1,556	486	—
Total estimated probable undeveloped reserves (MMcfe)	817,675	712,725	61,884
Standardized Measure (millions)	$ 420	$ 146	—
PV-10 (millions)(2)(10)	$ 563	$ 202	—
Estimated total probable reserves:			
Natural gas (MMcf).	939,506	522,442	61,884
Natural gas liquids (MBbls)	64,877	31,227	—
Oil (MBbls)	1,556	486	—
Total estimated probable reserves (MMcfe)	1,338,105	712,725	61,884
Standardized Measure (millions)	$ 701	146	—
PV-10 (millions)(2)(11)	935	202	2
Estimated possible developed reserves:			
Natural gas (MMcf).	84,124	—	—
Natural gas liquids (MBbls)	8,146	—	—
Oil (MBbls)	—	—	—
Total estimated possible developed reserves (MMcfe)	133,000	—	—
Standardized Measure (millions)	$ 53	—	—
PV-10 (millions)(2)(12)	$ 70	—	—
Estimated possible undeveloped reserves:			
Natural gas (MMcf).	540,878	381,941	—

	December 31, 2022		December 31, 2021	2020
Natural gas liquids (MBbls)		16,876	32,047	—
Oil (MBbls)		789	1,841	—
Total estimated possible undeveloped reserves (MMcfe)		646,868	585,269	—
Standardized Measure (millions)	$	248	$ 51	—
PV-10 (millions)(2)(13)	$	331	$ 75	—
Estimated total possible reserves:				
Natural gas (MMcf).		625,002	381,941	—
Natural gas liquids (MBbls)		25,022	32,047	—
Oil (MBbls)		789	1,841	—
Total estimated possible reserves (MMcfe)		779,868	585,269	—
Standardized Measure (millions)	$	301	$ 51	—
PV-10 (millions)(2)(14)	$	400	$ 75	—

(1) Prices for natural gas, oil and NGLs, respectively, used in preparing our estimated proved reserves and the associated PV-10 Value based on SEC Pricing (i) at December 31, 2022 were $6.358 per MMBtu (Henry Hub), $93.67 per Bbl (WTI Cushing) and pricing equal to 36.7% of WTI Cushing, (ii) at December 31, 2021 were $3.598 per MMBtu (Henry Hub), $66.56 per Bbl (WTI Cushing) and pricing equal to 39.5% of WTI Cushing and (iii) at December 31, 2020 were $1.985 per MMBtu (Henry Hub), $39.57 per Bbl (WTI Cushing) and pricing equal to 47% of WTI Cushing.

(2) PV-10 refers to the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. PV-10 is not a financial measure calculated in accordance with GAAP because it does not include the effects of income taxes on future net revenues. PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. Neither PV-10 nor Standardized Measure represent an estimate of the fair market value of our oil and natural gas properties. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and gas properties. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure reported in accordance with GAAP, but rather should be considered in addition to the Standardized Measure.

(3) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved developed reserves as of December 31, 2022, 2021 and 2020:

	December 31, 2022	2021	2020
PV-10 (millions)	$ 7,389	$2,672	$552
Present value of future income taxes discounted at 10%	(1,580)	(553)	(48)
Standardized Measure	$ 5,809	$2,119	$504

(4) Proved undeveloped reserves as of December 31, 2022 and 2021 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

(5) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our PUD, probable and possible reserves, which may cause us to decrease the amount

of our PUD, probable and possible reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our PUD, probable and possible reserves to become uneconomic to develop, which would cause us to remove them from their respective reserve category.

(6) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved undeveloped reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	**2021**	**2020**
PV-10 (millions)	$1,566	$ 403	$ 9
Present value of future income taxes discounted at 10%	(381)	(108)	(3)
Standardized Measure	$1,185	$ 294	$ 6

(7) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	**2021**	**2020**
PV-10 (millions)	$ 8,955	$3,074	$561
Present value of future income taxes discounted at 10%	(1,961)	(661)	(51)
Standardized Measure	$ 6,994	$2,413	$510

(8) Estimates of probable and possible reserves, respectively, and the respective future cash flows related to such estimates, are inherently imprecise and are more uncertain than proved reserves, and the future cash flows related to such estimates. For more information regarding the presentation of probable and possible reserves, see "*Business — Preparation of Reserves Estimates and Internal Controls.*"

(9) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated probable developed reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	**2021**	**2020**
PV-10 (millions)	$372	$ —	$ —
Present value of future income taxes discounted at 10%	(91)	—	—
Standardized Measure	$281	$ —	$ —

(10) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated probable undeveloped reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	**2021**	**2020**
PV-10 (millions)	$ 563	$202	$ —
Present value of future income taxes discounted at 10%	(143)	(56)	—
Standardized Measure	$ 420	$146	$ —

(11) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated probable reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	**2021**	**2020**
PV-10 (millions)	$ 935	$202	$ —
Present value of future income taxes discounted at 10%	(234)	(56)	—
Standardized Measure	$ 701	$146	$ —

(12) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated possible developed reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$ 70	$ —	$ —
Present value of future income taxes discounted at 10%	(17)	—	—
Standardized Measure	$ 53	$ —	$ —

(13) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated possible undeveloped reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$330	$ 75	$ —
Present value of future income taxes discounted at 10%	(83)	(24)	—
Standardized Measure	$248	$ 51	$ —

(14) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated possible reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$ 400	$ 75	$ —
Present value of future income taxes discounted at 10%	(100)	(24)	—
Standardized Measure	$ 301	$ 51	$ —

During the years ended December 31, 2022 and 2021, we incurred costs of approximately $54.0 million and $7.2 million, respectively, to convert 74.0 Bcfe and 19.4 Bcfe, respectively, of proved undeveloped reserves to proved developed reserves. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2022 and 2021 are approximately $1,089.6 million and $578.3 million, respectively, over the next five years, substantially all of which we expect to finance through cash flow from operations. Our development programs through the year ended December 31, 2022 focused on refracturing under-stimulated wells and designing and drilling new wells in both our Barnett and Marcellus assets. All of our PUD reserves are scheduled to be developed within five years of their initial disclosure as PUDs. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.*"

In early 2023, natural gas commodity prices decreased significantly, and we expect this lower natural gas commodity pricing environment to continue at least into the second quarter of 2023. Due to our desire to be a prudent operator and exercise capital discipline in this pricing environment, in March 2023, we decreased our capital expenditures budget for development of natural gas properties for 2023 to $81.0 million from our original budget of $278.0 million, which was the amount applied in connection with the preparation of the estimates of our reserves as of December 31, 2022. We estimate that this reduction in 2023 capital expenditures would result in a decrease in our proved reserves, standardized measure value of proved reserves and the PV-10 value of proved reserves, as of December 31, 2022, by approximately 4.1%, 3.8% and 3.9%, respectively. If the current lower natural gas commodity pricing environment extends beyond 2023, we will continue to maintain capital discipline and reflect corresponding capital expenditure changes in our estimated reserves as of December 31, 2023. These changes would mainly impact proved undeveloped reserves and proved developed non-producing reserves, which collectively represent approximately 27.9% of our total estimated proved reserves as of December 31, 2022.

2022 Activity

During the year ended December 31, 2022, the Company's proved reserves increased by 1,694.1 Bcfe. The increase in proved reserves was primarily due to the acquisition of the 2022 Barnett Assets. Other factors that contributed to the increase in proved reserves during 2022 included increasing commodity pricing, which improved economics, improved recoveries due to the application of restimulation technology to producing wells and the addition of NGL rich locations to the drilling schedule. The Company produced 279.5 Bcfe during the year ended December 31, 2022.

Revisions of previous estimates consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 182.9 Bcfe as a result of higher average pricing during 2022 for natural gas, NGLs and oil. An additional upward revision of 52.0 Bcfe was made to proved developed reserves for performance adjustments. Upward revisions were offset by downward revisions to proved undeveloped reserves of 246.0 Bcfe relating to 76.0 gross (53.1 net) locations in the Marcellus and Barnett that were removed from the drilling schedule in exchange for locations with more favorable economics, as discussed in the following explanation of extensions and discoveries in 2022. Additional downward revisions of 67.3 Bcfe and 42.9 Bcfe were made to proved undeveloped reserves related to performance and increased development costs, respectively.

Extensions and discoveries primarily consisted of the addition of 389.5 Bcfe from 71.0 gross (66.4 net) locations recognized as a result of our revised evaluation of properties acquired through our Devon Barnett Acquisition. The added locations are more rich in NGLs than the previously recognized locations that were removed from the 2021 drilling schedule, as discussed in the preceding explanation of revisions of previous estimates in 2022. Additional extensions consisted of proved undeveloped reserves of 85.8 Bcfe related to 27.0 gross (12.8 net) locations in NEPA and the Barnett that were recognized from acreage acquired in 2021 and as a result of the revised 2022 drilling plan. Extensions related to proved developed reserves of 74.1 Bcfe consisted of 23.0 gross (13.0 net) newly drilled wells on locations previously classified as unproved.

Purchases of minerals in place consisted of 1,237.1 Bcfe and 227.9 Bcfe of proved developed and proved undeveloped reserves, respectively, from the Exxon Barnett Acquisition. The acquired reserves consisted of operated working interests in 2,289.0 gross (1,696.4 net) wells and 53.0 gross (48.7 net) undeveloped locations.

Improved recoveries consisted of 80.5 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2022.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 73.9 Bcfe related to the completion of 19.0 gross (5.5 net) wells on proved undeveloped locations during the year ended December 31, 2022.

2021 Activity

During the year ended December 31, 2021, the Company’s proved reserves increased by 1,808.5 Bcfe. The increase in proved reserves was primarily due to increasing commodity pricing improving economics, and additions to the drilling schedule for both proved developed and undeveloped reserves. The Company produced 245.8 Bcfe during the year ended December 31, 2021.

Revisions of previous estimates primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 715.9 Bcfe and 245.6 Bcfe, respectively, as a result of higher average pricing during 2021 for natural gas, NGLs and oil. The remaining upward adjustment of 139.8 Bcfe relates to upward performance adjustments of 219.2 Bcfe to proved developed reserves offset by a downward revision of 79.4 Bcfe to proved developed reserves due to increased production costs.

Extensions and discoveries increased as a result of the completion of our evaluation of properties acquired through our Devon Barnett Acquisition, 550.1 Bcfe of proved undeveloped reserves was recognized for 123 gross (94.8 net) locations added to the Company’s revised drilling schedule during 2021. Additional extensions consisted of proved undeveloped reserves of 162.5 Bcfe related to 13.0 gross (9.6 net) locations in the Marcellus Basin recognized from acquired acreage and the revised 2021 drilling plan. Extensions related to proved developed reserves of 15.4 Bcfe consisted of 10.0 gross (3.0 net) newly drilled wells.

Purchases of minerals in place consisted of 17.7 Bcfe of proved developed reserves from the acquisition of additional working interests in 601.0 gross (14.6 net) wells and 1.8 Bcfe of proved undeveloped reserves from the acquisition of additional working interests in 18.0 gross (1.0 net) locations, each of which were in addition to the Company's previously held working interests in wells or working interests in locations in the Barnett.

Improved recoveries consisted of 205.4 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2021.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 19.4 Bcfe related to the completion of 4.0 gross (3.9 net) wells on proved undeveloped locations during the year ended December 31, 2021.

2020 Activity

During the year ended December 31, 2020, the Company's proved reserves increased by 1,684.5 Bcfe. The increase in proved reserves was due to the Devon Barnett Acquisition offset by downward revisions primarily due to lower average pricing for natural gas during 2020.The Company produced 111.7 Bcfe during the year ended December 31, 2020.

Revisions of previous estimates of proved undeveloped reserves primarily consisted of a downward revision to proved undeveloped reserves of 146.7 Bcfe due to a combination of performance adjustments and lower average pricing of natural gas during 2020, and a downward revision of 186.5 Bcfe which removed locations due to lower average pricing of natural gas during 2020. Proved developed reserves were adjusted downward by 49.3 Bcfe due to lower average natural gas prices and performance.

There were no extensions and discoveries of proved developed or proved undeveloped reserves during the year ended December 31, 2020.

Purchases of minerals in place consisted of 2,178.7 Bcfe of proved developed reserves from the acquisition of 4,296.0 gross wells (3,867.5 net) from the Devon Barnett Acquisition.

Estimated Reserves at NYMEX Strip Pricing

The following table provides our total estimated proved reserve, probable reserve and possible reserve information prepared by Ryder Scott as of December 31, 2022, using NYMEX strip prices as of market close on December 31, 2022 and PV-10 Value and the Standardized Measure for such period. We have included this information in order to provide an additional method of presentation of the fair value of our assets and the cash flows that we expect to generate from those assets based on the market's forward-looking pricing expectations as of December 31, 2022. The historical 12-month pricing average in our December 31, 2022 disclosures above does not reflect the prevailing natural gas and oil futures. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of natural gas and oil prices as of a certain date, although we caution investors that this information should be viewed as a helpful alternative, not a substitute, for the data presented based on SEC Pricing. In addition, we believe that NYMEX strip pricing provides relevant and useful information because it is widely used by investors in our industry as a basis for comparing the relative size and value of our reserves to our peers. Our estimated reserves based on NYMEX futures were otherwise prepared on the same basis as our SEC reserves for the comparable period. Actual future prices may vary significantly from the NYMEX strip prices on December 31, 2022. Actual revenue and value generated may be more or less than the amounts disclosed. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. In addition, estimates of probable and possible reserves are inherently imprecise and are more uncertain than proved reserves but have not been adjusted for risk due to that uncertainty, and therefore they may not be comparable with each other and should not be summed either together or with estimates of proved reserves. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves*."

	December 31, 2022
Estimated proved developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	3,656,043
Producing	3,328,444
Non-producing	327,599
Natural gas liquids (MBbls)	163,725
Producing	150,473
Non-producing	13,252
Oil (MBbls)	1,059
Producing	1,059
Non-producing	0
Total estimated proved developed reserves (MMcfe)	4,644,747
Producing	4,237,636
Non-producing	407,111
Standardized Measure (millions)	$ 3,250
PV-10 (millions)(1)	$ 4,067
Estimated proved undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	1,021,746
Natural gas liquids (MBbls)	36,937
Oil (MBbls)	565
Total estimated proved undeveloped reserves (MMcfe)(2)(3)	1,246,758
Standardized Measure (millions)	$ 415
PV-10 (millions)(4)	$ 599
Estimated total proved reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	4,677,789
Natural gas liquids (MBbls)	200,662
Oil (MBbls)	1,624
Total estimated proved reserves (MMcfe)	5,891,505
Standardized Measure (millions)	$ 3,665
PV-10 (millions)(5)	$ 4,675
Estimated probable developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	363,215
Natural gas liquids (MBbls)	25,556
Oil (MBbls)	—
Total estimated probable developed reserves (MMcfe)(3)(6)	516,551
Standardized Measure (millions)	$ 128
PV-10 (millions)(7)	$ 174
Estimated probable undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	511,913
Natural gas liquids (MBbls)	29,770
Oil (MBbls)	1,072
Total estimated probable undeveloped reserves (MMcfe)(3)(6)	696,965
Standardized Measure (millions)	$ 141
PV-10 (millions)(8)	$ 198
Estimated total probable reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	875,128

	December 31, 2022
Natural gas liquids (MBbls)	55,326
Oil (MBbls)	1,072
Total estimated probable reserves (MMcfe)(3)(6)	1,213,516
Standardized Measure (millions)	$ 269
PV-10 (millions)(9)	$ 372
Estimated possible developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	83,986
Natural gas liquids (MBbls)	8,143
Oil (MBbls)	0
Total estimated possible developed reserves (MMcfe)(3)(6)	132,844
Standardized Measure (millions)	$ 26
PV-10 (millions)(10)	$ 35
Estimated possible undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	458,394
Natural gas liquids (MBbls)	7,062
Oil (MBbls)	273
Total estimated possible undeveloped reserves (MMcfe)(3)(6)	502,404
Standardized Measure (millions)	$ 90
PV-10 (millions)(11)	$ 126
Estimated total possible reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	542,380
Natural gas liquids (MBbls)	15,205
Oil (MBbls)	273
Total estimated possible reserves (MMcfe)(3)(6)	635,248
Standardized Measure (millions)	$ 116
PV-10 (millions)(12)	$ 161

(1) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved developed reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 4,076
Present value of future income taxes discounted at 10%	(826)
Standardized Measure	$ 3,250

(2) Proved undeveloped reserves as of December 31, 2022 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

(3) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our PUD, probable and possible reserves, which may cause us to decrease the amount of our PUD, probable and possible reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our PUD, probable and possible reserves to become uneconomic to develop, which would cause us to remove them from their respective reserve category.

(4) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved undeveloped reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 599
Present value of future income taxes discounted at 10%	(184)
Standardized Measure	$ 415

(5) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 4,675
Present value of future income taxes discounted at 10%	(1,010)
Standardized Measure	$ 3,665

(6) Estimates of probable and possible reserves, respectively, and the respective future cash flows related to such estimates, are inherently imprecise and are more uncertain than proved reserves, and the future cash flows related to such estimates. For more information regarding the presentation of probable and possible reserves, see "*Business — Preparation of Reserves Estimates and Internal Controls.*"

(7) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated probable developed reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 174
Present value of future income taxes discounted at 10%	(46)
Standardized Measure	$ 128

(8) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated probable undeveloped reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 198
Present value of future income taxes discounted at 10%	(57)
Standardized Measure	$ 141

(9) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated probable reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 372
Present value of future income taxes discounted at 10%	(103)
Standardized Measure	$ 269

(10) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated possible developed reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 35
Present value of future income taxes discounted at 10%	(9)
Standardized Measure	$ 26

(11) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated possible undeveloped reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 126
Present value of future income taxes discounted at 10%	(36)
Standardized Measure	$ 90

(12) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated possible reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 161
Present value of future income taxes discounted at 10%	(45)
Standardized Measure	$ 116

RISK FACTORS

Investing in our common stock involves risks. The information in this prospectus should be considered carefully, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements" and the following risks, before making an investment decision. The risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. The occurrence of any of the following risks or additional risks and uncertainties that are currently immaterial or unknown could materially and adversely affect our business, financial condition, liquidity, results of operations, cash flows, prospects or ability to pay dividends to holders of our common stock. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to Our Upstream Business and Industry

The volatility of natural gas and NGL prices due to factors beyond our control may materially and adversely affect our business, financial condition or results of operations and our ability to make capital expenditures, meet our debt service obligations and other financial commitments and pay dividends on our common stock.

Our revenues, operating results, cash available to pay dividends and the carrying value of our natural gas properties, as well as our ability to make capital expenditures (including the $29.0 to $34.0 million estimated total project cost of the Barnett Zero Project, the $14.0 to $24.0 million estimated total project cost of the Cotton Cove Project and the $250.0 million we expect to spend over the next three years in connection with our CCUS project development partnership with Verde CO2), meet our debt service obligations and other financial commitments and pay dividends on our common stock, depend significantly upon the prevailing market prices for natural gas and NGLs. According to the EIA, during the period from January 1, 2021 through December 31, 2022, the Henry Hub natural gas spot price reached a high of $23.86 per MMBtu on February 17, 2021 and a low of $2.43 per MMBtu on April 5, 2021. Henry Hub natural gas spot prices trended higher after the Russia-Ukraine conflict first commenced, rising from $4.78 per MMBtu on February 24, 2022 to a high of $9.85 per MMBtu on August 22, 2022, according to the EIA; however, such prices subsequently dropped to $3.52 on December 31, 2022, as a result of a warmer-than-normal winter. Prices for natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors beyond our control. These factors include, but are not limited to:

- worldwide and regional economic conditions impacting the global supply of, and demand for, natural gas and NGLs, including inflation;
- the price, amount, timing and quantity of foreign imports of natural gas and NGLs;
- political conditions in or affecting other producing countries, including the armed conflict between Russia and Ukraine and associated economic sanctions on Russia and conditions in China, the Middle East, Africa and South America;
- the level of global drilling, exploration and production;
- the level of global inventories;
- prevailing market prices on local price indexes in the areas in which we operate and expectations about future commodity prices;
- the impact on worldwide economic activity of an epidemic, outbreak or other public health events, such as the COVID-19 pandemic or threat of such epidemic or outbreak, or any government response to such occurrence or threat;
- increased associated natural gas and NGL production resulting from higher oil prices and the related increase in oil production;
- the proximity of our natural gas and NGL production to, and capacity and cost of, natural gas and NGL pipelines and other transportation and storage facilities, and other factors that result in differentials to benchmark prices;
- local and global supply and demand fundamentals and transportation availability;

- United States storage levels of natural gas and NGLs;
- weather conditions and other natural disasters;
- domestic and foreign governmental regulations, including environmental initiatives and taxation;
- overall domestic and global economic conditions;
- the value of the dollar relative to the currencies of other countries;
- stockholder activism or activities by non-governmental organizations to restrict the exploration, development and production of natural gas, NGLs and oil to minimize emissions of carbon dioxide, a GHG;
- the actions of OPEC and other oil producing countries, including Russia;
- speculative trading in natural gas and NGL derivative contracts;
- technological advances affecting energy consumption and energy supply;
- the price, availability and acceptance of alternative energy sources; and
- the impact of energy conservation efforts.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas price movements accurately. Changes in natural gas and NGL prices have a significant impact on the amount of natural gas and NGLs that we can produce economically, the value of our reserves, our cash flows and our ability to satisfy obligations under our firm transportation and storage agreements. Historically, natural gas and NGL prices and markets have been volatile, and those prices and markets are likely to continue to be volatile in the future. For example, during the year ended December 31, 2022, the Henry Hub natural gas spot price reached a high of $9.85 per MMBtu in August 2022 and subsequently dropped to a low of $3.52 in December 2022 as a result of a warmer-than-normal winter, and during the year ended December 31, 2021, the Henry Hub natural gas spot price reached a high of $23.86 per MMBtu in February 2021 and a low of $2.43 per MMBtu in April 2021, in each case, according to the U.S. Energy Information Administration (the “EIA”).

A substantial percentage of our natural gas and NGL production is gathered, processed and transported by a single third party and all of our natural gas production is marketed by a single third party.

Approximately 99% of our natural gas and NGL production for the assets we acquired in the Devon Barnett Acquisition, which comprised approximately 69%, 77% and 44% of our total natural gas and NGL production for years ended December 31, 2022, 2021 and 2020, respectively, is gathered, processed and transported by EnLink using its gas gathering systems, gas transportation system and gas processing facilities. Any termination or sustained disruption in the gathering, processing and transportation of our natural gas and NGL production by EnLink on its systems and in its facilities would materially and adversely affect our financial condition and results of operations and may limit our ability to pay dividends on our common stock.

We utilize an unaffiliated third party to market all of our natural gas production to various purchasers, which consist of credit-worthy counterparties, including utilities, LNG producers, industrial consumers, major corporations and super majors, in our industry. We rely on the credit worthiness of such third-party marketer, who collects directly from the purchasers and remits to us the total of all amounts collected on our behalf less their fee for making such sales. Our business, financial condition, results of operations and ability to pay dividends on our common stock would be materially adversely affected if such third party fails to remit to us amounts collected by it on our behalf for such sales or if, in the future, it becomes necessary or advisable for us to replace our third-party marketer and we experience disruption in the marketing and sale of our natural gas production for so long as we are unable to find a replacement marketer.

Our estimated natural gas, NGL and oil reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.

Numerous uncertainties are inherent in estimating quantities of natural gas, NGL and oil reserves. The process of estimating natural gas, NGL and oil reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, including assumptions regarding future natural gas, NGL and oil prices, subsurface characterization, production levels and operating and development costs. For example, our estimates of our reserves at SEC Pricing are based on the unweighted first-day-of-the-month arithmetic average commodity prices over the prior 12 months in accordance with SEC guidelines. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of those estimates. Sustained lower natural gas, NGL and oil prices will cause the 12-month unweighted arithmetic average of the first-of-the-day price for each of the 12 months preceding to decrease over time as the lower natural gas, NGL and oil prices are reflected in the average price, which may result in the estimated quantities and present values of our reserves being reduced. To the extent that natural gas, NGL and oil prices become depressed or decline materially from current levels, such conditions could render uneconomic a portion of our proved natural gas, NGL and oil reserves, and we may be required to write down our proved reserves.

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

As a result, estimated quantities of natural gas, NGL and oil reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Over time, we may make material changes to our reserve estimates. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas, NGL and oil attributable to any particular group of properties, the classifications of reserves based on risk of non-recovery and estimates of future net cash flows.

In addition, 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 that 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 and possible reserves, respectively, and the respective future cash flows related to such estimates, and should not be summed arithmetically with estimates of either proved or possible reserves, respectively, and the respective 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. 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.

Estimates of possible reserves, and the future cash flows related to such estimates, are also inherently imprecise and are more uncertain than estimates of proved and probable reserves, respectively, and the respective future cash flows related to such estimates, but have not been adjusted for risk due to that uncertainty. Because of such uncertainty, estimates of possible reserves, and the future cash flows related to such estimates, may not be comparable to estimates of proved and probable reserves, respectively, and the respective future cash flows related to such estimates, and should not be summed arithmetically with estimates of either proved or probable reserves, respectively, and the respective 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 possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible 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, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve 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. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. 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 we believe 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.

The present value of future net revenues from our proved natural gas, NGL and oil reserves, or PV-10, will not necessarily be the same as the current market value of our estimated proved natural gas, NGL and oil reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated natural gas, NGL and oil reserves. We currently base the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding 12 months. Actual future net revenues from our natural gas, NGL and oil reserves will be affected by factors such as:

- actual prices we receive for natural gas, NGL and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- transportation and processing; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of our natural gas, NGL and oil properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues 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 natural gas, NGL and oil industry in general. Actual future prices and costs may differ materially from those used in the present value estimate.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Recovery of PUD reserves requires significant capital expenditures and successful drilling operations. As of December 31, 2022, approximately 1,714.8 Bcfe, or 28%, of our total estimated proved reserves were undeveloped or behind pipe. The reserve data included in our reserve report assumes that substantial capital expenditures will be made to develop non-producing reserves. We cannot be sure that the estimated costs attributable to our natural gas, NGL and oil reserves are accurate. We may need to raise additional capital to develop our estimated PUD reserves over the next five years and we cannot be certain that additional financing will be available to us on acceptable terms, or at all. Additionally, sustained or further declines in commodity prices may require us to revise the future net revenues of our estimated PUD reserves and may result in some projects becoming uneconomical. Further, our drilling efforts may be delayed or unsuccessful and actual reserves may prove to be less than current reserve estimates, which could have a material adverse effect on our financial condition, future cash flows, results of operations and ability to pay dividends on our common stock.

As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures as compared to the completion cost of a vertical well and therefore may result in fewer wells being completed in any given year. The incremental required capital expenditures are the result of greater measured depths and additional hydraulic fracture stages in horizontal wellbores.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows, results of operations and ability to pay dividends on our common stock.

In general, the volume of production from natural gas, NGL and oil properties declines as reserves are depleted, with the rate of decline depending on each reservoir's characteristics. Except to the extent that we conduct successful exploration, exploitation and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future natural gas and NGL production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves as well as the pace of drilling and completion of new wells. Additionally, the business of exploring for, exploiting, developing or acquiring reserves is capital intensive. Recovery of our reserves, particularly undeveloped reserves, will require significant additional capital expenditures and successful drilling operations. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and NGL reserves would be impaired.

If natural gas and NGL prices become depressed for extended periods of time or decline materially from current levels, we may be required to record write-downs of the carrying value of our proved natural gas and NGL properties.

We follow the successful efforts method of accounting for natural gas producing activities. Impairment is indicated when a triggering event occurs and the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. If undiscounted future cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in our results of operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. Triggering events could include, but are not limited to, an impairment of natural gas and NGL reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, declines in commodity prices and changes in the utilization of midstream gathering and processing assets. If impairment is indicated, fair value is calculated using a discounted-cash flow approach and any excess of carrying value is expensed. Undeveloped natural gas and NGL properties are evaluated for impairment on a regular basis, based on the results of the exploratory activity and management's evaluation. If the assessment indicates an impairment, an impairment loss is recognized. Future price decreases could result in reductions in the carrying value of our assets and an equivalent charge to earnings.

We periodically evaluate our unproved natural gas, NGL and oil properties to determine recoverability of our costs and could be required to recognize non-cash charges in the earnings of future periods.

As of December 31, 2022, we carried unproved natural gas, NGL and oil property costs of $15.5 million. GAAP requires periodic evaluation of unproved natural gas, NGL and oil property costs on a project-by-project basis. These evaluations are affected by the results of exploration activities, commodity price outlooks, planned future sales or expirations of all or a portion of these leases and the contracts and permits relevant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the costs invested in each project, we will recognize non-cash charges in future periods.

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

Acquiring natural gas and NGL properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential liabilities, including environmental liabilities. Such assessments are inherently inexact and uncertain. For these reasons, the properties we have acquired or will acquire in the future may not produce as projected. Further, the annual decline rates of reserves are estimated decline rates, which could ultimately be materially different than actual annual decline rates. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. We perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as pipe corrosion or groundwater contamination, when a review is performed. We may be unable to obtain contractual indemnities from the seller for liabilities created 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.

Our failure to correctly assess reservoir and infrastructure characteristics of the natural gas and NGL properties that we acquire or have acquired, or to identify material defects or liabilities associated with such properties, or actual decline rates that differ materially from estimated decline rates, could have a material adverse effect on our financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Market conditions or operational impediments may hinder our access to natural gas and NGL markets or delay or curtail our natural gas and NGL production.

Market conditions or the unavailability of natural gas and NGL processing, transportation or storage arrangements may hinder our access to natural gas and NGL markets or delay or curtail our production. The availability of a ready market for our natural gas and NGL production depends on a number of factors, including the demand for and supply of natural gas and NGLs, the proximity of our natural gas and NGL production to and capacity of pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities, competition for such facilities and the inability of such facilities to gather, transport, store or process our natural gas and NGL production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions, or pandemics such as the COVID-19 pandemic or regulatory action related thereto.

Our firm transportation and storage agreements require us to pay demand charges for firm transportation and storage capacities that we do not utilize. If we fail to utilize our firm transportation and storage capacities due to production shortfalls or otherwise, then our margins, results of operations and financial performance could be adversely affected.

We enter into long-term firm transportation agreements, which as of December 31, 2022, provided us with a network of approximately 1,087,500 MMBtu/d of combined firm transportation capacity to East Coast, Gulf Coast, and Southeast markets as it relates to our upstream business units. Additionally, BKV-BPP Power has long-term firm transportation and storage agreements, which, as of December 31, 2022, provided BKV-BPP Power with 75,000 MMBtu/d of firm transportation and 2,812,500 MMBtu of firm storage with Energy Transfer. We are obligated under these arrangements to pay a demand charge for firm transportation and storage capacity rights on a majority these pipeline and storage systems regardless of the amount of pipeline or storage capacity we utilize, subject to our right to release all or a portion of our firm transportation or storage capacities to other shippers and reduce our exposure to demand charges. Our minimum aggregate required payments per year under firm gathering and transportation agreements are approximately $62.3 million for 2023, $42.6 million for 2024, $23.2 million for 2025, $21.3 million for 2026, $20.0 million for 2027, and $64.0 million for 2028 and beyond. See “*Business — Marketing and Differentials*.”

If our anticipated production does not exceed the minimum quantities provided in the agreements, and we are unable to purchase natural gas and NGLs from third parties or release our capacity to other shippers, then our margins, results of operations and financial performance could be adversely affected.

Drilling for natural gas wells is a high-risk activity with many uncertainties that could adversely affect our business, financial condition or results of operations.

Drilling natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive natural gas and NGL reserves (including “dry holes”). We must incur significant expenditures to drill and complete wells, the costs of which are often uncertain. It is possible that we will make substantial expenditures on drilling and not discover reserves in commercially viable quantities.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled. The cost of our drilling, completing and well operations may increase and our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and changes in weather patterns;
- compliance with, or changes in, environmental laws and regulations relating to air emissions, hydraulic fracturing and disposal of produced water, drilling fluids and other wastes, laws and regulations imposing conditions and restrictions on drilling and completion operations and other laws and regulations, such as tax laws and regulations;
- the availability and timely issuance of required governmental permits and licenses; and
- the availability of, costs associated with, and terms of contractual arrangements for, properties, including mineral licenses and leases, pipelines, facilities and equipment to gather, process, compress, store, transport and market natural gas and NGLs and related commodities.

For instance, in our drilling operations across NEPA and the Barnett from time to time we experience certain issues and the occurrence of risks, including, for example, mechanical and instrument or tool failures, drilling difficulties associated with drilling in swelling clay or shales and unconsolidated formation, particularly in certain parts of our Barnett development acreage, wellbore instability and other geological hazards, loss of well control, loss of drilling fluids, inability to establish fluid circulation, loss of drill pipe, loss of casing integrity, stuck tools and drill pipes, insufficient cementing of casing, among other typical shale drilling challenges.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators in each case due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations.

Drilling, completions, workover and hydraulic fracturing operations are operationally complex activities which present certain risks that could adversely affect our business, financial condition or results of operations.

In our drilling operations, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; drilling difficulties associated with drilling in swelling clay or shales and unconsolidated formation, particularly in select parts of our Barnett development acreage; wellbore instability and other geological hazards; loss of well control and associated hydrocarbon release and/or natural gas clouds; loss of drilling fluids circulation; surface spills of various drilling or well fluids; subsurface collision with existing wells; proximity of adjacent water wells or aquifers; inability to establish drilling fluid circulation; loss or compromise of drill pipe or casing integrity; surface pumping operations and associated pressure and hydrocarbon hazards; stuck and lost-in-hole tools, drill pipe or casing; large drilling equipment and machinery including electrical hazards; insufficient cementing of casing causing unwanted casing pressure or fluid migration; surface overpressure events from large machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; structural damage and collapse to large equipment and machinery; major damage or malfunction to key equipment or processes; in certain instances, close proximity of operations to residences and/or communities; among other typical shale basin drilling challenges and risks.

In our hydraulic fracturing, workover and completions activities, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; loss of well control and associated hydrocarbon release and/or natural gas clouds; well kick or flowback during completion or fracturing operations; lost or stuck in hole wireline, coiled tubing or workover strings and tools; loss or compromise of workover string, tubing or casing integrity; large completions, wireline, coiled tubing and workover rig equipment and machinery including electrical hazards; insufficient cementing of casing causing unwanted casing pressure or fluid migration while fracturing or thereafter; proximity of adjacent water wells or aquifers and adjacent producing wells; surface spills of various fracturing, freshwater or well fluids or chemicals; surface pumping and flowback operations and associated pressure and hydrocarbon hazards; surface overpressure events from large machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; structural damage and collapse to large equipment and machinery; major damage or malfunction to key equipment or processes; in certain instances, close proximity of operations to residences and/or communities; among other typical fracturing, workover and completion challenges and risks.

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

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

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of factors, including commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling conditions, drilling results, lease expirations, gathering system, marketing and transportation constraints, regulatory approvals, urban growth and other factors. If commodity prices become depressed or decline materially from current levels, the number of locations would decrease as increasing numbers of locations would become uneconomic, and any such decrease may be significant. Even to the extent any locations remain capable of economic production, we may determine not to drill such locations until commodity prices recover. Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce natural gas and NGLs from these drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acreage on which some of the identified locations are located, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

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

To the extent we target emerging areas, the results of our horizontal drilling efforts in such areas will generally be more uncertain than drilling results in areas that are more developed and have more established production from horizontal formations. Because emerging areas and associated target formations have limited or no production history, we are less able to rely on past drilling results in those areas as a basis to predict our future drilling results. In addition, horizontal wells drilled in shale formations, as distinguished from vertical wells, utilize multilateral wells and stacked laterals, all of which may be subject to well spacing, density and proration requirements, which requirements could adversely impact our ability to maximize the efficiency of our horizontal wells related to reservoir drainage over time. Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, access to gathering systems, takeaway capacity constraints or otherwise, availability of drilling surface acreage, or commodity prices decline, our investment in these areas may not be as economic as we anticipate, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local landowners and other sources for use in our operations. Some areas in which we have operations have experienced drought conditions that could result in restrictions on water availability or use. Such drought conditions and water stress may become more frequent or intense as a result of climate change. If we are unable to obtain water to use in our operations from local sources or are unable to transport and store such water, we may be unable to economically produce natural gas and NGLs in the affected areas, which could have an adverse effect on our financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

The unavailability or high cost of equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third-party services to maximize the efficiency of our operations. The cost of oilfield services typically fluctuates based on demand for those services. While we currently have excellent relationships with oilfield service companies, there is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages, quality or the high cost of equipment, supplies or personnel could delay or adversely affect our development and exploitation operations, which could have a material adverse effect on our business, financial condition or results of operations.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

As of December 31, 2022, we operated approximately 94% of our net (72% of our gross) acreage. With respect to our natural gas midstream business, we do not operate the NEPA midstream entities, and in the Barnett, as of December 31, 2022, approximately 23% of our gross operated production volumes were gathered and processed by our owned and operated system. We have limited control over properties and midstream facilities which we do not operate or do not otherwise control operations. If we do not operate or otherwise control the properties and midstream facilities in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. The failure of an operator of wells in which we own a non-operating interest or an operator of midstream facilities in which we have an interest to adequately perform operations, an operator’s financial difficulties, including as a result of price volatility or an operator’s breach of the applicable agreements, could reduce our production and revenues. The success and timing of the drilling and development activities on properties operated by others, as well as the midstream activities with respect to our assets, therefore, depends upon a number of factors outside of our control, including the operator’s timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology.

Risks Related to Our Power Generation Business

We operate our power generation business through a joint venture which we do not control.

We and BPPUS each have a 50% interest in the BKV-BPP Power Joint Venture. For the years ended December 31, 2022 and 2021, our interest in the BKV-BPP Power Joint Venture represented approximately 0.8% and approximately 0.2% of our revenues, respectively.

In accordance with the terms of the Limited Liability Company Agreement of BKV-BPP Power (the "BKV-BPP Power LLC Agreement"), the BKV-BPP Power Joint Venture is managed by a board of directors (the "BKV-BPP board") consisting of eight members, four of which are appointed by us and four of which are appointed by BPPUS. Consequently, BKV-BPP Power may not take certain material actions without the consent of BPPUS. For example, without the prior consent of BPPUS, the BKV-BPP Power Joint Venture may not:

- make distributions or determine the amount of cash to be distributed;
- make capital expenditures, including acquisitions; or
- incur indebtedness in an amount greater than $1,500,000.

See "*Certain Relationships and Related Party Transactions — BKV-BPP Power Joint Venture — BKV-BPP Power Limited Liability Company Agreement.*"

We face certain risks associated with shared control, and BPPUS may at any time have economic, business or legal interests or goals that are inconsistent with ours.

We may be required to make additional capital contributions to the BKV-BPP Power Joint Venture.

In addition, BPPUS may be required to make additional capital contributions to fund items approved in the annual budget or other matters approved by the board of directors of BKV-BPP Power. We do not control the timing or the amount which we may be required to contribute. If we fail to make additional capital contributions to BKV-BPP Power, as approved by the board of directors, such failure could be deemed an event of default under the BKV-BPP Power LLC Agreement. If an event of default occurs, the non-defaulting party will be entitled to (i) sell the assets of the joint venture and dissolve the joint venture on reasonable terms deemed acceptable to the BKV-BPP board, (ii) obtain specific performance of the non-defaulting party's obligations, and/or (iii) exercise any other right or remedy provided in law or in equity. If we default on any obligation to make an additional capital contribution to BKV-BPP Power and any of these events were to occur, it could have a material adverse effect on the BKV-BPP Power Joint Venture and on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Operation of electric generation facilities involves significant risks and hazards customary to the power industry that could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

The ongoing operation of Temple I involves risks that include performance below expected levels of output or efficiency, as well as the unavailability of key equipment or breakdown or failure of equipment or processes (including an inability to obtain key equipment from Siemens natural gas generators and steam turbines and Benson heat recovery steam generators, which are used by Temple I), due to wear and tear, latent defect, design error or operator error or force majeure events, among other things. Unplanned outages of generating units, including extensions of scheduled outages due to mechanical failures or other problems, occur from time to time and are an inherent risk of the business. Unplanned outages typically increase operation and maintenance expenses and capital expenditures and may reduce revenue available to be distributed to BPPUS and us as a result of selling fewer megawatt hours or require us to incur significant costs as a result of obtaining replacement power from third parties in the open market to satisfy forward power sales obligations. Our inability to operate the BKV-BPP Power electric generation assets efficiently, manage capital expenditures and costs and generate distributions from Temple I could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Maintenance, expansion and refurbishment of electric generation facilities involve significant risks that could result in unplanned power outages or reduced output.

Temple I may require periodic upgrading and improvement. Any unexpected operational or mechanical failure, including failure associated with breakdowns and forced outages, could reduce the facility's generating capacity below expected levels, reducing potential cash distributions to BPPUS and us. Unanticipated capital expenditures associated with maintaining, upgrading or repairing our facility may also reduce profitability.

If we make any major modifications to Temple I, we may be required to install the best available control technology or to achieve the lowest achievable emission rates as such terms are defined under and determined pursuant to the new source review provisions of the Clean Air Act ("CAA") at the time of such modifications. Any such modifications could likely result in substantial additional capital expenditures. We may also choose to repower, refurbish or upgrade our facility based on our assessment that such activity will provide adequate financial returns. Such facility requires time for development and capital expenditures before commencement of commercial operations, and key assumptions underpinning a decision to make such an investment may prove incorrect, including assumptions regarding construction costs, timing, available financing and future fuel and power prices. These events could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Temple I may operate, wholly or partially, without long-term power sales agreements.

Temple I may operate without long-term power sales agreements for some or all of its generating capacity and output and therefore be exposed to market fluctuations. Without the benefit of long-term power sales agreements for the facility, we cannot be sure that the BKV-BPP Power Joint Venture will be able to sell any or all of the power generated by the facility at commercially attractive rates or that the facility will be able to operate profitably. This could lead to less predictable revenues, future impairments of the facility's property, plant and equipment or the closing of the facility, resulting in economic losses and liabilities, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Our near-term business plan contemplates the execution of midstream contracts with certain third parties in order to allow us to supply our own natural gas directly to Temple I and its firm intrastate natural gas storage service at the Bammel storage facility. We cannot assure you that we will be successful in obtaining the commercial contracts necessary to facilitate direct delivery of our natural gas production to Temple I on commercially reasonable terms, or at all.

We cannot assure you that we will succeed in any effort to establish midstream contracts that would allow us to supply our own natural gas directly to Temple I and its firm intrastate natural gas storage service at the Bammel storage facility. Although the physical infrastructure exists to supply our own natural gas directly to Temple I and the Bammel storage facility, our ability to utilize that infrastructure depends on whether we can successfully negotiate and enter into new midstream contracts on satisfactory terms or at all. If we fail to enter into such contracts on satisfactory terms or at all, we may be unable to achieve the synergistic cost savings we anticipated in connection with the BKV-BPP Power Joint Venture, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Our long-term business plan involves the expansion of our retail power business and the development of opportunities to offer end consumers household energy sourced from a Scope 1, 2 and 3 carbon neutral gas product.

We intend to continue to build out our power generation business through opportunistic acquisitions of power generation assets and expand into retail power. However, we may be unable to execute on our business plans, demand for retail power services may not develop on a large or economic scale, we may be exposed to market price risk if our supply obligations are not fully hedged or suppliers fail to perform, weather events could be more extreme or mild than expected, which could affect customer demand in a manner that adversely affects revenue, or we may fail to operate a retail power business effectively. If we were unable to develop a commercially successful retail power business effectively or at all, it could limit our future growth in retail energy markets, and any failure to do so in whole or in part or in any significant measure could have a material adverse effect on our retail power business. Additionally, we intend to develop our ability to provide a Scope 1, 2 and 3 carbon neutral gas product, which we refer to as MNZ gas, and we believe that the expansion of our presence in the retail power space, along with the synergistic and opportunistic growth of our upstream, midstream and power generation businesses, will provide our retail business the opportunity to offer end consumers household energy sourced from MNZ gas. Our ability to offer end consumers energy sourced from MNZ gas is dependent, among other things, on our ability to continue to develop our CCUS business, obtain third-party certifications for our MNZ and grow our midstream, power generation and retail power business.

BKV-BPP Power enters into financially settled Heat Rate Call Options ("HRCOs") that may expose it to basis and buyback risk in its operations.

To reduce its exposure to fluctuations in the market price of electricity and natural gas, BKV-BPP Power enters into financially settled HRCOs, which are contracts for the financial purchase and sale of power based on a floating price of natural gas at a predetermined location using a predetermined conversion factor, or heat rate, required to turn the fuel input into electricity. BKV-BPP Power is exposed to basis risk in its operations when its derivative contracts settle financially, and it delivers physical electricity on different terms. For example, if BKV-BPP Power enters into an HRCO, it hedges its electricity production based on an agreed price for that electricity, but physical electricity must be delivered to delivery points in the market it serves. BKV-BPP Power is exposed to basis risk between the hub price specified in the HRCO and the price that it receives for the sales of physical electricity. BKV-BPP Power attempts to hedge basis risk where possible, but hedging instruments are sometimes not economically feasible or available in the quantities that it requires. BKV-BPP Power's hedging activities do not provide it with protection for all of its basis risk and could result in economic losses and liabilities, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Additionally, by using derivative instruments to economically hedge exposure to changes in power prices, we could limit the benefit we would receive from increases in the power prices, which could have an adverse effect on our financial condition. For example, as of December 31, 2022, BKV-BPP Power had unrealized gains of approximately $0.7 million on two HRCOs as a result of decreased power pricing. In the event BKV-BPP Power is not able to satisfy its obligations under the HRCO, it must purchase power at prevailing market price to satisfy the HRCO. Likewise, increases in power pricing could limit the benefit we receive under HRCOs and result in losses. Either such event could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Our costs, results of operations, financial condition, cash flows and ability to pay dividends could be adversely impacted by the disruption of the fuel supplies necessary to generate power at Temple I, whether as a result of failure of contractual counterparties, disruption in fuel delivery infrastructure or otherwise.

Delivery of natural gas to fuel Temple I is dependent upon the infrastructure (including natural gas pipelines) available to serve such generation facility as well as upon the continuing financial viability of contractual counterparties. As a result, the BKV-BPP Power Joint Venture is subject to the risks of disruptions or curtailments in the production of power at our generation facility if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure. Any such disruptions or curtailments could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Risks Related to Our CCUS Business

Our ability to establish large scale CCUS projects is subject to numerous risks and uncertainties. We may be unsuccessful in developing our CCUS business as currently anticipated, either wholly or in significant measure.

A key element of our business strategy includes the development of a CCUS business. We have no prior experience in the development and operation of a CCUS business, which poses different challenges and risks than our existing upstream and midstream businesses. We may be unable to execute on our business plans, demand for these new services may not develop on a large or economic scale, or we may fail to operate our CCUS business effectively. Our CCUS business may also present novel issues in law, taxation, emission offset accounting and accreditation, safety or environmental policy, subsurface storage, supply chain, project design and other areas that we may not be able to manage effectively or that could change considerably. Management's assessment of the risks in this line of business may be inexact and not identify or resolve all the problems that we would face. If we are unsuccessful in timely developing a commercially successful CCUS business, our future growth and results of operations may be materially and adversely affected, and we may be unable to realize much of our current business plans, including timely reaching our goal of net zero Scope 1, 2 and 3 emissions across our owned and operated upstream businesses, either by the dates projected or at all.

Due to the early stage nature of CCUS projects and the sector generally, CCUS projects face considerable risks. In particular, the Barnett Zero Project, our BKV dCarbon Ventures CCUS project with EnLink, and the Cotton Cove Project face, and any of our potential CCUS projects in the future, including potential projects we expect to develop with Verde CO2 as well as the pipeline of CCUS projects currently under evaluation, will face, operational, technological, regulatory and financial risks (including the risk that EnLink, or any of our other future counterparties to a CCUS project, will not meet their financial or performance obligations with respect to the CCUS project).

Although we have identified ten potential CCUS projects in addition to the Barnett Zero Project and Cotton Cove Project, these additional potential projects are in different stages of the evaluation process. We have not entered into any definitive agreements with respect to these potential projects and as such, we cannot assure you that we will reach FID, or complete, any of such potential projects. Our stated goals of timely achieving net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses are dependent, in part, on being able to commercially develop several of our existing pipeline of CCUS projects.

Further, our ability to successfully develop the Barnett Zero Project with EnLink, the Cotton Cove Project and any future potential CCUS projects, including projects we expect to develop with Verde CO2, depends on a number of factors that we are not able to fully control, including the following:

- Commercial scale carbon capture is an emerging sector, and there are not substantial precedents to gauge the likely range of structures or economic terms that will be necessary to reach agreeable terms.
- CCUS injection wells are currently subject to overlapping state and federal jurisdiction and new and evolving regulatory frameworks. The timetable for issuance of permits and authorizations required for a CCUS project is uncertain and could entail a multi-year process. The issuance of permits may be subject to regulatory delays and third-party challenges. We cannot guarantee that we will be able to obtain necessary permits on a timely basis, on favorable terms, or at all.
- As CCUS and carbon management represent an emerging sector, regulations may evolve rapidly, which could impact the feasibility of one or more of our anticipated projects. To the extent regulatory requirements are amended or more stringently enforced or new regulatory requirements are added, we may incur additional delays and/or costs in the pursuit of one or more of our carbon capture projects, which costs may be material or may render any one or more of our projects uneconomical.
- We may not own the pore space at all of our CCUS project sites, which may require us to enter into agreements with multiple owners to secure the necessary real estate rights for the extent of the geologic formation that may be utilized. The failure to obtain necessary pore space rights from all owners, in the absence of a state law mechanism for eminent domain or forced amalgamation, could have a material adverse effect on any proposed CCUS project.
- Robust monitoring, recordkeeping and reporting required in connection with CCUS projects may increase the costs of such operations. Different methodologies may be required to satisfy various regulatory and non-regulatory requirements regarding GHG emissions/sequestration at one or more of our projects, including, but not limited to, compliance with the EPA mandatory Greenhouse Gas Reporting Program.
- CCUS injection wells and carbon sequestration reservoirs or formations may experience integrity, operating or boundary breaches resulting in additional costs, liability and risk from undesired well casing pressures, breakthrough of injected CO_2 to the land surface, CO_2 plume migration outside of

expected or modeled results into undesired or unwanted surface or subsurface areas, well integrity issues or various other outcomes.

- Carbon capture may be viewed as a pathway to the continued use of fossil fuels, notwithstanding that CO_2 emissions are intended to be captured. There may be organized opposition to carbon capture, including our projects, alleging concerns relating to the environment, environmental justice, health or safety, or the federal and state governments may cease supporting carbon capture and sequestration.
- The development of a CCUS project may require us to enter into long-term joint ventures with large carbon emitters (which may need to finance and build, often over a multi-year period, the equipment to capture CO_2 emissions from various industrial processes) and operators of infrastructure for transporting CO_2 (or other GHGs), and we may not be able to do so on agreeable terms or at all.

The development of our CCUS business is expected to require material capital investments.

We estimate the aggregate investment required by us to fund a sufficient number of the identified potential CCUS projects in order to achieve our Scope 1, 2 and 3 emissions goals through the sequestration of our and third-party emissions to be between approximately \$1.3 billion and \$1.8 billion over the next seven to ten years. We currently estimate the total investment required by us for the Barnett Zero Project to be between \$29.0 and \$34.0 million and the total investment required by us for the Cotton Cove Project to be between approximately \$14.0 and \$24.0 million. In addition, we currently expect to invest up to \$250.0 million over the next three years in connection with our CCUS project development partnership with Verde CO2. Our CCUS projects are expected to have material capital requirements, and we expect to fund these CCUS projects with a combination of cash flows from operations and up to 40% in funding from external sources, which may include joint ventures, project-based equity partnerships and federal grants. We anticipate that some of these project costs will be borne by third-party investors in these projects, including emitters, landowners and other stakeholders. However, there is no certainty that we will be able to obtain external funding on a timeline sufficient to achieve our goals, on commercially reasonable terms or at all. Our access to external funding depends on a number of factors, including general market conditions, potential investors' confidence in our CCUS program, business model, growth potential and our current and expected future earnings as well as the liquidity needs of the external funding sources themselves. We may face intense competition from a variety of other companies and financing structures for such limited investment capital. If we are unable to obtain a sufficient level of external funding for our CCUS projects, we may be required to abandon or materially delay certain projects, which in turn could negatively impact our ability to realize our business plan or to reach our near term and long term net zero goals on our anticipated time frame or at all. We similarly may not be able to reach out positive revenue goals for our CCUS business on the timeline we have predicted, which may likewise adversely impact our business or financial condition. CCUS activities subject us to the financial risks of rising costs of equipment and capital, possible delays in acquiring them, along with the financial impact of our expending capital on these activities in advance of realizing any CCUS cash flows, any of which could negatively impact our financial condition and operational results in future periods.

To the extent CO_2 transportation pipelines are not already present in proposed project areas, or if they do not extend to one or more of our project sites, we may be required to convert existing non-CO_2 pipelines, or build new CO_2 pipelines or lateral connections, which will require more time before we can bring together captured CO_2 emissions and transport them to appropriately tested and prepared sequestration sites, require much larger capital expenditures and may be subject to various environmental and other permitting requirements and authorizations as well as third-party easements that could be difficult or costly to obtain, which may render one or more projects uneconomical or impractical. The availability of eminent domain for carbon capture pipelines varies by state and can be highly controversial; there may be organized opposition to eminent domain for carbon capture pipelines, including those associated with our projects, from environmental or landowner groups. Additionally, even in areas where such pipelines are in place, our use of them may require reaching agreements on CO_2 transportation with operators of the pipelines.

The commercial viability of our CCUS projects depends, in part, on certain financial and tax incentives provided by the U.S. federal government.

The economics of CCUS projects depend on financial and tax incentives that could be changed or terminated and that may not currently be sufficient for our CCUS projects to be economical. For example, our qualification for enhanced Section 45Q tax credits is dependent upon our ability to meet certain wage and apprenticeship requirements. If we are unable to obtain the Section 45Q tax credits included in our financial assumptions, many of our proposed CCUS projects may no longer be commercially viable and may not be completed. We cannot assure you that we will be successful in obtaining any or all of the Section 45Q tax credits currently available.

CCUS projects will require storage of CO_2 in subterranean reservoirs over long periods of time. If accidental releases or subsurface migration of CO_2 from our CCUS activities were to occur in the course of operating one or more of our CCUS sites, there is the risk of government recapture of Section 45Q tax credits previously claimed by or issued to us, as well as a risk of trespass or other tort or property claims related to the accidental release or migration of CO_2 beyond the permitted boundaries of any anticipated project as well as the potential for fines and penalties for violations of environmental requirements.

A successful CCUS project in the United States must comply with what we anticipate will be a stringent regulatory scheme involving multiple federal and state permits applicable to the subsurface injection of CO_2 for geologic sequestration. Moreover, when we are the operator of a CCUS project, we must demonstrate and maintain levels of financial assurance sufficient to cover the cost of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response. There is no assurance that we will be successful in obtaining permits or adequate levels of financial assurance for one or more of our CCUS projects or that permits can be obtained on a timely basis, whether due to difficulty with the technical demonstrations required to obtain such permits, public opposition, undeveloped regulatory framework, or otherwise.

There can be no assurances that we will be able to execute on our CCUS strategy and successfully develop the Barnett Zero Project with EnLink in the Barnett, the Cotton Cove Project or any future CCUS projects, including projects we expect to develop with Verde CO2, and any failure to do so in whole or in any significant measure could have a material adverse effect on our ability to reach our near term and long term net zero goals on our anticipated time frame or at all, as well as on our liquidity, financial condition, results of operations and ability to pay dividends on our common stock.

Risks Related to Our Midstream Business

Midstream operations are complex activities which present certain risks that could adversely affect our business, financial condition or results of operations.

In operating our midstream and production facilities, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; loss of well, pressure vessel, tank or other related equipment control and associated hydrocarbon release and/or natural gas clouds; loss or compromise of casing integrity during production; unwanted casing pressure or fluid migration during production operations; unwanted migration of sequestered carbon dioxide or other fluids in injection wells; temporary and permanent surface facility operations and associated pressure and hydrocarbon hazards; surface overpressure events and other hazards resulting from machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; pipeline loss of containment due to integrity issues, pipeline strikes or other reasons and associated hydrocarbon release; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; major damage or malfunction to key equipment or processes; structural damage and collapse to equipment and machinery; in certain instances, close proximity of operations to residences and/or communities; among other typical midstream and production facilities challenges and risks.

We depend on our natural gas midstream system for the gathering and processing of a substantial percentage of our natural gas production.

As of December 31, 2022, we own and operate approximately 778 miles of gathering pipeline, 65 midstream compressors and one amine processing unit. In the event that our natural gas midstream system is unable to process our natural gas production, or its operations are otherwise disturbed or curtailed, we could experience a disruption in our ability to transport our natural gas production, which could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Construction of midstream projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations, cash flows and liquidity.

From time to time, we may plan and construct midstream projects, some of which may take a number of months before commercial operation, such as construction of natural gas, NGL and produced water gathering or transportation systems and construction of related facilities. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, government and regulatory approval, compliance with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our financial condition, results of operations, cash flows and ability to pay dividends on our common stock. The construction of these midstream facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and financial condition could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

We do not own all of the land on which our pipelines and other midstream facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and other midstream facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases, or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere, and reduce our revenue.

Risks Related to Our Business Generally

Substantially all of our oil and gas and midstream properties are concentrated in Texas and Northeast Pennsylvania, making us vulnerable to risks associated with operating in only two geographic areas.

Substantially all of our oil and gas and midstream properties are located in Texas and Northeast Pennsylvania. As a result of this geographic concentration, an adverse development in the natural gas, NGL and oil and/or midstream business in either or both of these operating areas could have a greater impact on our financial condition, results of operations and cash available to pay dividends on our common stock than if we were more geographically diversified. Due to the concentrated nature of our properties, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, water shortages or other drought related conditions, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of natural gas, NGLs and oil.

In addition, the weather in these areas can be extreme and can cause interruption in our operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital expenditures. For instance, during 2021, Winter Storm Uri in Texas resulted in over 1.5 Bcfe of curtailed production and significant freezing and associated downtime across our facilities and equipment.

The effect of fluctuations on supply and demand may become more pronounced within specific geographic natural gas, NGL and oil producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. A number of our properties could experience any of the same 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 diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

A financial crisis or deterioration in general economic, business or industry conditions could materially adversely affect our results of operations, financial condition and ability to pay dividends on our common stock.

Concerns over global economic conditions, instability in the banking sector, stock market volatility, energy costs, geopolitical issues, inflation and U.S. Federal Reserve interest rate increases in response, the availability and cost of credit, and slowing of economic growth in the United States and fears of a recession have contributed and may continue to contribute to 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 continued in 2022 and has continued into 2023, due to a substantial increase in the money supply, a stimulation focused fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 5.4% in June 2021 to 7.0% in December 2021 and a peak of 9.1% in June 2022, then moderated to 8.2% in September 2022, 6.5% in December 2022 and 6% in February 2023. We have experienced supply chain constraints and inflationary pressure on our cost structure throughout 2022. Some supply chain constraints and inflationary pressures could persist in 2023 but are expected to plateau. For example, since the end of the third quarter of 2021, our natural gas production business line has experienced 13% inflationary cost increases. In the year ended December 31, 2022, our new drill and completion program experienced 22% overall inflationary cost increases. In addition, during such period, significant cost increases have occurred in services, labor, fuel, proppant and steel tubulars, with tubular cost increases exceeding 75%. 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, our ability to procure materials and equipment in a timely and cost-effective manner, if at all, may be negatively impacted, which could materially adversely impact our results of operations, financial condition and ability to pay dividends on our common stock.

Similarly, we cannot predict the impact that high market volatility and instability in the banking sector could have on economic activity and our business in particular. The failure of banks and financial institutions and measures taken, or not taken, by governments, businesses and other organizations in response to these events could adversely impact our business, financial conditions and results of operations.

In addition, continued hostilities between Russia and Ukraine and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. The ongoing conflict in Ukraine could continue to have repercussions globally and in the United States by continuing to cause uncertainty, not only in the natural gas, NGL and oil markets, but also in the capital markets. Such uncertainty could result in stock price volatility and supply chain disruptions, as well as higher natural gas, NGL and oil prices which could potentially result in increased inflation worldwide and could negatively impact demand for natural gas, NGLs, oil and electricity.

Concerns about global economic growth can result in a significant adverse impact on global financial markets and commodity prices. In addition, any financial crisis may cause us to face limitations on our ability to borrow under our debt agreements, service our debt obligations, access the debt and equity capital markets and complete asset purchases or sales and may cause increased counterparty credit risk on our derivative instruments and such counterparties to cause us to post collateral guaranteeing performance.

Further, if there is a financial crisis or the economic climate in the United States or abroad deteriorates, worldwide demand for hydrocarbon-based products could materially decrease, which could impact the price at which natural gas and NGLs from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately materially adversely impact our results of operations, financial condition and ability to pay dividends on our common stock. If a material adverse change occurs in our business such that an event of default occurs under our debt agreements, the lenders under such agreements may be able to accelerate the maturity of our debt.

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

We face risks related to pandemics, epidemics, outbreaks or other public health events, or the threat thereof that are outside of our control, and could significantly disrupt our business and operational plans and adversely affect our liquidity, financial condition, results of operations, cash flows and ability to pay dividends on our common stock. The COVID-19 pandemic has adversely affected the global economy and has resulted in unprecedented governmental actions in the United States and countries around the world, including, among other things, social distancing guidelines, travel restrictions and stay-at-home orders, among other actions, which caused a significant decrease in activity in the global economy and the demand for oil, and to a lesser extent, natural gas and NGLs.

The nature, scale and scope of the above-described events, combined with the uncertain duration and extent of governmental actions, prevent us from identifying all potential risks to our business. Additionally, the effects of the COVID-19 pandemic might worsen the likelihood or the impact of other risks already inherent in our business. We believe that the known and potential impacts of the COVID-19 pandemic and related events include, but are not limited to, the following:

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

New variants of COVID-19 could cause further commodity market volatility and resulting financial market instability, or any other event described above, and these are variables beyond our control that may adversely impact our operating cash flows, distributions from unconsolidated affiliates, our ability to pay dividends on our common stock and our ability to access the capital markets.

The success of our business plan depends, in part, on achieving our near term and long term net zero goals on our anticipated time frame.

The development of our CCUS business, as well as the expansion of our “Pad of the Future” program and the effectiveness of our leak detection and repair emissions monitoring program and our installation of solar power, are critical to our ability to achieve our emissions goal of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025 and aspirations to offset Scope 3 emissions from our owned and operated upstream businesses by the early 2030s. We may not meet our near term or long term goals by our target date or at all. Likewise, our estimated reduction and offsets expected from these initiatives may turn out to be inaccurate. The standards and expectations regarding carbon accounting and the processes for measuring and counting GHG emissions and GHG emission reductions are evolving. Changes in GHG emission accounting methodologies or new developments related to climate science could impact our ability to claim emissions reductions related to our CCUS business or otherwise. As a result, it is possible that factors outside of our control could give rise to the need to restate or revise our emissions reduction goals, cause us to miss them altogether, or limit the impact of success of achieving our goals.

Moreover, our CCUS business and all of our CCUS projects are in the early stages of development and while we have reached FID and entered into definitive agreements with respect to the Barnett Zero Project and reached internal FID for the Cotton Cove Project, we have not reached FID or entered into definitive agreements necessary to execute any of the other potential projects we have identified in "*Business — Our Operations — Carbon Capture, Utilization and Sequestration*" and may not be able to reach agreements on terms acceptable to us, or to achieve our projected timeline for commercial operations. In addition, the development of our CCUS business is expected to require material capital investments and the projected timeline for commercial operations depends on our ability to secure external funding for a material portion of the expected investment. Furthermore, the commercial viability of our CCUS projects depends, in part, on certain financial and tax incentives provided by the U.S. federal government. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits, the details of which have been released only in part with additional details expected in future guidance.

Our ability to establish large scale CCUS projects is subject to numerous risks and uncertainties, including reaching definitive agreements with third parties and obtaining necessary permits and other regulatory approvals, and we may be unable to execute on some or all of these projects, including the projects for which we have reached FID, on the timeline we anticipate, on terms acceptable to us or at all. We may not be successful in developing any of our currently identified potential CCUS projects or others, our actual costs with respect to any CCUS projects may exceed our current estimate and we may not be able to realize the anticipated reductions and offsets in emissions. There can be no assurances that we will be able to execute on our CCUS strategy and successfully develop the Barnett Zero Project with EnLink in the Barnett, the Cotton Cove Project or any future CCUS projects, and any failure to do so in whole or in any significant measure could have a material adverse effect on our ability to meet our Scope 1, 2 and 3 owned and operated upstream emissions goals. Even if we are able to successfully develop such projects, the underlying agreements may not apportion us the right to claim all emissions offsets, which may impact our net zero strategy. Additionally, to the extent we meet our emissions reduction goals, they may be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our emissions impact instead of actual changes in our emissions reduction performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, or that the offsets we do purchase will successfully achieve the emissions reductions they represent. See "*— Risks Related to Our CCUS Business.*"

Our revolving credit facilities are uncommitted and as a result the lenders under the facilities have no obligation to honor any request for a loan or the issuance of a letter of credit.

We maintain two revolving credit facilities for purposes of funding certain of our working capital needs: a $55.0 million uncommitted credit facility with Oversea-Chinese Banking Corporation Limited, which includes a $25.0 million sublimit for the issuance of standby letters of credit and a $50.0 million uncommitted credit facility with Standard Chartered Bank, which includes a $35 million sublimit for the issuance of standby letters of credit. We use these revolving credit facilities for letters of credit and working capital purposes. However, as uncommitted facilities, the lenders under these facilities are not obligated to honor any request for a loan or the issuance of a letter of credit. Further, our borrowings under these revolving credit facilities are repayable upon demand by the applicable lender and the interest rates and fees under these revolving credit facilities can be changed by the applicable lender in its discretion. The refusal of either or both of the lenders under these revolving credit facilities to provide additional borrowings, or the demand by either of these lenders to demand repayment in full of any borrowings under either of these facilities, could materially and adversely affect our liquidity, capital resources or result of operations. Further any such occurrences could cause us to materially delay or abandon one or more capital projects or to fund dividends. Finally, we may not be able to timely replace these sources of liquidity at equivalent cost to us or at all.

We may not be able to generate enough cash flow to meet our debt obligations or fund our other liquidity needs.

As of April 13, 2023, we had total outstanding debt of $695.0 million, which consisted of (i) $75.0 million in aggregate principal amount under the $75 Million A&R Loan Agreement (as defined herein) with BNAC, a wholly owned subsidiary of our parent, Banpu, which is subordinated to our obligations under the Term Loan Credit Agreement, (ii) $570.0 million in aggregate principal amount under the Term Loan Credit Agreement, (iii) $15.0 million in aggregate principal amount under our SCB Credit Facility and (iv) $35.0 million in aggregate principal amount under our OCBC Credit Facility. The Term Loan Credit Agreement, which we entered into in connection with closing of the Exxon Barnett Acquisition on June 30, 2022, allows us to borrow up to $600.0 million in the aggregate in the form of multiple loans during the period commencing with the effective date and ending on the date that is six months thereafter solely to finance the Exxon Barnett Acquisition, provides that amounts repaid may not be reborrowed, and requires annual amortization payments equal to 20% of the original balance. On June 30, 2022, we borrowed $570.0 million of term loans under the Term Loan Credit Agreement. In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, operating expenses and capital expenditures.

In addition to the Term Loan Credit Agreement, we are party to the Revolving Credit Facilities (as defined herein), which include a $55.0 million uncommitted OCBC Credit Facility and a $50.0 million uncommitted SCB Credit Facility (as defined herein) and the Revolving Credit Agreement. We use the Revolving Credit Facilities for letters of credit and working capital purposes and borrowings under the Revolving Credit Agreement for working capital purposes.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, fluctuations in commodity prices, results of operations and other factors, many of which are beyond our control. Our ability to meet our debt service obligations also may be impacted by changes in prevailing interest rates, as borrowings under the Subordinated Intercompany Loan Agreements, the Term Loan Credit Agreement, the Revolving Credit Facilities and the Revolving Credit Agreement bear interest at floating rates.

We may not generate sufficient cash flow from operations. Without sufficient cash flow, there may not be adequate future sources of capital to enable us to service our indebtedness or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be required to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets; or
- restructuring or refinancing debt.

We may not be able to complete such alternative strategies on satisfactory terms, if at all. Our inability to generate sufficient cash flows to satisfy our debt obligations and fund our liquidity needs, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations and may limit our ability to pay dividends on our common stock.

We may be unable to achieve or maintain a low target level of indebtedness.

If we refinance all of our existing debt, or we receive the requisite consents from our existing lenders, we may incur significant additional indebtedness in the future in order to make acquisitions or to develop our properties or for other general corporate purposes.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;

- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends on our common stock, and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate, or other purposes.

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

The agreements governing our indebtedness contain restrictive covenants that may limit our ability to respond to changes in market conditions, pursue business opportunities or pay dividends to our stockholders.

The agreements governing our indebtedness contain restrictive covenants that limit our ability to, among other things:

- incur additional debt;
- incur additional liens;
- sell, transfer or dispose of assets;
- merge or consolidate, wind-up, dissolve or liquidate;
- pay dividends and distributions on, or repurchases of, equity;
- make acquisitions and investments, other than direct investments in natural gas, NGL and oil properties and other assets in permitted lines of business;
- enter into certain transactions with our affiliates;
- enter into sale-leaseback transactions;
- make optional or voluntary payment of subordinated debt;
- change the nature of our business;
- change our fiscal year to make changes to the accounting treatment or reporting practices;
- amend constituent documents; and
- enter into certain hedging transactions.

The Term Loan Credit Agreement and the Revolving Credit Agreement contain, and any future debt agreement may contain, covenants that prohibit us from paying dividends on our common stock under certain circumstances. For additional information regarding the restrictions contained in the Term Loan Credit Agreement and the Revolving Credit Agreement on our ability to pay dividends to our stockholders, see "— *Risks Related to the Offering and Our Common Stock — The agreements governing our indebtedness impose restrictions on dividend payments*."

In addition, the Term Loan Credit Agreement, the Revolving Credit Agreement and certain of our other debt agreements require us to maintain financial ratios and tests. Also, the administrative agent under the Term Loan Credit Agreement has approval rights over our annual budget and our quarterly cash forecasts for the succeeding 12-month period. In addition to customary events of default, the Term Loan Credit Agreement and the Revolving Credit Agreement include an event of default if there is a material adverse change in our business.

The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures, withstand a continuing or future downturn in our business or pay dividends to our stockholders.

If we are unable to comply with the restrictions and covenants in our debt agreements, there could be an event of default under the terms of such agreements, which could result in an acceleration of repayment.

If we are unable to comply with the restrictions and covenants in the Subordinated Intercompany Loan Agreements, Term Loan Credit Agreement, Revolving Credit Facilities, the Revolving Credit Agreement or any future debt agreement or if we default under the terms of the Subordinated Intercompany Loan Agreements, Term Loan Credit Agreement, Revolving Credit Facilities, the Revolving Credit Agreement or any future debt agreement, there could be an event of default. Our ability to comply with these restrictions and covenants, including meeting any financial ratios and tests, may be affected by events beyond our control. Further, if, after this initial public offering, Banpu and its wholly owned subsidiaries at any time cease to own at least 51% of our equity interests, or if any such holder allows any lien to exist on our equity interests that they own, such event will be an event of default under the Term Loan Credit Agreement and the Revolving Credit Agreement, which may result in amounts owed by us thereunder to become immediately due and payable. Banpu has no obligation to maintain any particular percentage of equity ownership in the Company (other than the 180-day lock-up agreement and other restrictions described in "*Shares Eligible for Future Sale*") may at any time sell all or any portion of its equity interests in us. As a result, we cannot assure that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests. In the event of a default under the Subordinated Intercompany Loan Agreements, Term Loan Credit Agreement, Revolving Credit Facilities, the Revolving Credit Agreement or any future debt agreement, the lenders could terminate their commitments to lend or accelerate the loans and declare all amounts borrowed due and payable. If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend the Term Loan Credit Agreement, Revolving Credit Facilities, the Revolving Credit Agreement or any future debt agreement or obtain needed waivers on satisfactory terms.

In early 2023, natural gas prices began decreasing significantly from previous periods, which if sustained will cause non-compliance of the Company's fixed charge coverage ratio financial covenant beginning with the quarter ending June 30, 2023 and subsequent quarters, and its net leverage ratio financial covenant for the quarter ending December 31, 2023, which covenants are discussed in "*Note 4 — Debt*" and "*Note 15 — Credit and Other Risk*" in the Company's audited consolidated financial statements included elsewhere in this prospectus. Non-compliance with financial debt covenants will limit the Company's ability to draw on its existing credit facilities and could also result in our debt agreements being called early, which would move certain non-current financial obligations to current. As a result, the Company would have insufficient liquidity and capital resources to be able to repay those obligations. Additionally, the Company's reduced cash flow from operations could cause the Company not to meet its current and non-current financial obligations based on our current forecasts. Banpu has agreed to provide funding to allow the Company to meet its financial obligations until June 30, 2024, if necessary. The Company is also seeking waivers or amendments from lenders for certain debt covenants within the Term Loan Credit Agreement and revolving credit agreement through several quarters into 2024, and is also seeking increased availability for borrowings under the Company's existing credit facilities.

Our borrowings under the Subordinated Intercompany Loan Agreements, Term Loan Credit Agreement, Revolving Credit Facilities and Revolving Credit Agreement expose us to interest rate risk.

Our results of operations are exposed to interest rate risk associated with borrowings under the Subordinated Intercompany Loan Agreements, Term Loan Credit Agreement, Revolving Credit Facilities and Revolving Credit Agreement, which bear interest at rates based on the Secured Overnight Financing Rate ("SOFR") or an alternative floating interest rate benchmark. In response to inflation, the U.S. Federal Reserve increased interest rates multiple times in 2022 and 2023 and signaled that additional interest rate increases should be expected in 2023. Raising or lowering of interest rates by the U.S. Federal Reserve generally causes an increase or decrease, respectively, in SOFR and other floating interest rate benchmarks. As such, if interest rates increase, so will our interest costs. If interest rates continue to increase, it may have a material adverse effect on our results of operations, financial condition and ability to pay dividends on our common stock.

Our hedging activities do not provide downside protection for all of our production and could result in financial losses or could reduce our net income. Further, our derivative contracts contain certain restrictions and covenants.

From time to time, we enter into derivatives contracts in connection with our natural gas and NGLs, including, for instance, swaps, producer collars and enhanced three-way collars. These derivative arrangements are subject to mark-to-market accounting treatment, and the changes in fair market value of our derivative contracts are reported in our statement of operations and comprehensive loss each quarter, which may result in significant non-cash gains or losses. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

These derivative arrangements are designed to reduce our exposure to commodity price decreases.

Therefore, to the extent our production is not hedged, we are exposed to declines in commodity prices. In addition, our derivative arrangements may be inadequate to protect us from continuing and prolonged declines in commodity prices. Further, while designed to reduce our exposure to commodity price decreases, these derivatives arrangements may also limit the potential gains we might otherwise receive from increases in commodity prices if such prices rise over the price established by our derivative contracts. For example, for the years ended December 31, 2022 and 2021, we incurred realized losses on derivatives of $688.5 million and $268.7 million, respectively, $158.3 million and $31.0 million of which related to early termination of hedges, respectively. We incurred a realized gain on derivatives of approximately $10.4 million for the year ended December 31, 2020. For the years ended December 31, 2022 and 2020, we incurred an unrealized gains on derivatives of approximately $58.8 million and $10.3 million, respectively, and we incurred an unrealized loss on derivatives of approximately $115.2 million for the year ended December 31, 2021. In trying to manage our exposure to commodity price risk, we may end up with too many or too few derivative contracts, depending upon where commodity prices settle relative to our derivative price thresholds and how our natural gas and NGL volumes fluctuate relative to our expectations when the derivatives were established.

As of December 31, 2022, we have hedged approximately 245,000 MMBtu/d for the remainder of 2023. We have hedged approximately 5,300 Bbl/d of NGL production for the remainder of 2023. Our results of operations, liquidity and financial condition would be negatively impacted if prices of natural gas and NGLs were to become depressed or decline materially from current levels, or there is otherwise an unexpected material impact on commodity prices, and we have experienced variances in our results of operations and financial condition due to our hedging transactions.

Our hedging activities do not provide downside protection for all of our production. In addition, our ability to use hedging transactions to protect us from future commodity price declines will be dependent upon commodity prices at the time we enter into future hedging transactions and our future levels of hedging and, as a result, our future net cash flows may be more sensitive to commodity price changes. Further, if commodity prices decline materially, we will not be able to replace our hedges or enter into new hedges at favorable prices.

Further, our derivative contracts contain certain restrictions and covenants customary for such types of instruments. For example, an ISDA Master Agreement for certain of our derivative contracts (the "Master Agreement") previously contained a covenant that restricted us from creating, issuing, incurring or assuming additional indebtedness in excess of $75.0 million. In June 2022, in connection with the completion of the Exxon Barnett Acquisition, we borrowed $570.0 million of term loans under the Term Loan Credit Agreement. In connection with exceeding the $75.0 million indebtedness threshold, on August 4, 2022, we executed an amendment to the Master Agreement pursuant to which we were required to novate or terminate, at our election, at least $100.0 million in derivative contracts by October 4, 2022. On September 9, 2022, we terminated derivative contracts of $100.2 million with the counterparty to satisfy this requirement. In connection with such termination, we were required to make cash payments to the counterparty in an aggregate amount of $100.2 million, all of which was paid by November 30, 2022. The Master Agreement, as amended to date, includes a cross-default provision pursuant to which a default by us of the covenants under our Term Loan Credit Agreement would cause a default under the Master Agreement. See "*Note 15 — Credit and Other Risk*" to our audited consolidated financial statements included elsewhere in this prospectus for additional information regarding the Master Agreement.

Subject to restrictions in the Term Loan Credit Agreement and the Revolving Credit Agreement, our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. In the future, we may enter into additional derivative arrangements or reduce our derivative arrangements. The prices at which we hedge our production in the future will be dependent upon commodities prices at the time we enter into these transactions, which may be substantially higher or lower than current prices. Accordingly, our price hedging strategy may not protect us from significant declines in prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from future commodity price increases. It is also possible that a substantially larger percentage of our future production will not be hedged as compared with the next few years, which would result in our natural gas and NGL revenues becoming more sensitive to commodity price fluctuations.

Our hedging transactions could expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. The risk of counterparty nonperformance is of particular concern in the event of disruptions in the financial markets or the significant decline in commodity prices, which could lead to sudden changes in a counterparty's liquidity and impair their ability to perform under the terms of the derivative 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. Furthermore, the bankruptcy of one or more of our hedge providers or some other similar proceeding or liquidity constraint might make it unlikely that we would be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities.

During periods of falling commodity prices, our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

We may experience difficulty in achieving and managing future growth.

Future growth may place strains on our resources and cause us to rely more on project partners and independent contractors, possibly negatively affecting our financial condition, results of operations, cash flows and ability to pay dividends on our common stock. Our ability to grow will depend on a number of factors, including:

- our ability to acquire additional assets and to successfully integrate acquisitions we may make;
- the results of our drilling program;
- commodity prices;
- our ability to develop existing prospects;
- our ability to obtain leases or options on properties for which we have seismic data;
- our ability to acquire additional seismic data;
- our ability to identify and acquire new exploratory prospects;
- our ability to continue to retain and attract skilled personnel;

- our ability to maintain or enter into new relationships with project partners and independent contractors; and
- our access to capital.

We are a holding company with no operations of our own, and we depend on our subsidiaries and our joint venture for cash to fund all of our operations, taxes and other expenses and any dividends that we may pay.

Our operations are conducted entirely through our subsidiaries and the BKV-BPP Power Joint Venture. Our ability to generate cash to meet our debt and other obligations, to cover all applicable taxes payable and to declare and pay any dividends on our common stock is dependent on the earnings and the receipt of funds through distributions from our subsidiaries and the BKV-BPP Power Joint Venture. Our subsidiaries' and BKV-BPP Power's ability to generate adequate cash depends on a number of factors, including development of reserves, successful acquisitions of complementary properties, advantageous drilling conditions, natural gas, NGL and oil prices, successful production and sales of electricity, compliance with all applicable laws and regulations and other factors.

Our business is subject to operating hazards that could result in substantial losses or liabilities for which we may not have adequate insurance coverage.

Natural gas and NGLs operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of natural gas, NGLs or well fluids, fires, pipe, casing or cement failures, abnormal pressure, pipeline leaks, ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory, monitoring, and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- loss of, or delay in revenue;
- suspension or impairment of operations; and
- repairs to resume operations.

We maintain insurance against some, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our operations that include coverage for general liability, property damage to certain of our real and personal property, and certain personal property of others, excess liability, physical damage to our upstream and midstream properties, operational control of wells, redrilling expenses, pollution and cleanup, site pollution incidents, damage to lease property, business and contingent business interruption, management liability, automobile liability, third-party liability, workers' compensation, employer's liability, kidnap and ransom and other coverages. Our insurance policies provide coverage for losses or liabilities relating to pollution, but are largely limited to coverage for sudden and accidental occurrences. For example, the site pollution incident policy we maintain includes coverage for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operator's extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition, results of operations and ability to pay dividends on our common stock.

Additionally, we rely to a large extent on transportation owned and operated by third parties and damage to, or destruction of, those third-party facilities could affect our ability to process, transport and sell our production. To a limited extent, we maintain business interruption insurance related to our processing plants where we are insured for potential losses from the interruption of production caused by loss of or damage to the processing plant.

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 ability to grow.

There is intense competition for acquisition opportunities in our industry and we may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. We may not be able to obtain contractual indemnities from sellers for liabilities incurred prior to our purchase of the business, asset or property. No assurance can be given that we will be able to identify additional suitable acquisition or asset exchange opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. In addition, there can be no assurance that Banpu will not engage in competition with us in the future. See "*— Risks Related to Our Relationship with Banpu and its Affiliates — Banpu's interests, including interests in certain corporate opportunities, may conflict with our interests and the interests of our other stockholders. Conflicts of interest between us and Banpu could be resolved in a manner unfavorable to us and our other stockholders.*" Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions.

We may make acquisitions of properties or businesses that complement or expand our current business in the future. The successful acquisition of natural gas and NGL properties requires an assessment of several factors, including:

- recoverable reserves;
- future commodity prices;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and rely on numerous assumptions and we may not be able to identify accretive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Reviews may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when a review is performed. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Market forces often prevent us from negotiating contractual indemnification for environmental liabilities and require us to acquire properties on an "as is" basis.

The success of any of our acquisitions will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources which may divert management's attention from other business concerns. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. 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, results of operations, cash flows and ability to pay dividends on our common stock.

In addition, the Subordinated Intercompany Loan Agreements, Term Loan Credit Agreement, Revolving Credit Facilities and Revolving Credit Agreement will limit our ability to enter into mergers or combination transactions. These debt arrangements also limit our ability to incur indebtedness and liens, which could indirectly limit our ability to engage in acquisitions.

Our business requires substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms or be able to fund our working capital needs from cash flow from operations, which could lead to a decline in our reserves.

The energy industry is capital intensive. We have made and expect to continue to make substantial capital expenditures in our businesses for the acquisition, exploration, production and development of natural gas and NGL reserves, as well as the gathering, processing and transportation of natural gas and NGLs and the development of our CCUS business. Our capital expenditures in 2021 totaled $63.9 million, primarily relating to completion of drilled but uncompleted wells prior to January 1, 2021, projects to increase reserve recovery and investment in non-operated wells. Our capital expenditures in 2022 totaled $235.4 million, primarily relating to completion of drilled but uncompleted wells prior to January 1, 2022, investment in operated wells, projects to increase reserve recovery, and investment in non-operated wells.

The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of CO_2 transportation pipelines in proposed CCUS project areas, and legal, regulatory, environmental, technological and competitive developments. In early 2023, natural gas commodity prices decreased significantly, and we expect this lower natural gas commodity pricing environment to continue at least into the second quarter of 2023, and we have decreased our capital expenditures budget for development of natural gas properties for 2023 from $278.0 million to $81.0 million in response. A sustained decline in commodity prices may result in further decreases in our actual capital expenditures, which would negatively impact our ability to grow production. Although we intend to finance our future capital expenditures primarily through cash flow from operations and through available capacity under the Revolving Credit Facilities and the Revolving Credit Agreement, our future needs may require us to alter or increase our capitalization substantially through the increase in the size of our working capital facilities, issuance of additional debt or equity securities or the sale of assets.

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

- the estimated quantities of our natural gas and NGL reserves;
- the amount of hydrocarbon we produce from existing wells;
- the prices at which we sell our production;
- the levels of our operating expenses;
- take-away and storage capacity;
- our ability to acquire, locate, develop and produce new reserves; and
- our ability to borrow under the Revolving Credit Facilities, the Revolving Credit Agreement and any additional working capital facilities that we obtain.

If our revenues decrease as a result of lower commodity prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our planned capital budget or operations at current levels. For example, the recent decline in commodity prices may reduce the amount of capital the Company can raise through debt or equity financing. 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 capacity under the Revolving Credit Facilities are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties or our CCUS business, which in turn could lead to a decline in our reserves and production and a failure to meet our net zero goals, and could adversely affect our business, financial condition, results of operations and ability to pay dividends on our common stock.

We may be unable to dispose of nonstrategic assets on attractive terms and may be required to retain liabilities for certain matters.

We regularly review our asset base to assess the market value versus holding value of existing assets with a view to optimizing deployed capital. Our ability to dispose of nonstrategic assets or complete dispositions, such as acreage that we do not intend to place on our production schedule prior to lease expirations, could be affected by various factors, including the availability of buyers willing to purchase the nonstrategic assets at prices acceptable to us. Sellers typically retain certain liabilities or agree to indemnify buyers for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets.

As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenues.

The energy industry is intensely competitive, and we compete with other companies that have greater resources than we do. Our ability to acquire additional properties, to discover reserves in the future and to execute on potential CCUS projects will be dependent upon our ability to evaluate and select suitable properties to consummate transactions in a highly competitive market. Many of our larger competitors not only drill for and produce natural gas, NGLs and oil, but they also engage in refining operations and market petroleum and other products on a regional, national or worldwide basis. Our competitors may be able to pay more for natural gas and NGL properties, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit and attract capital at lower rates. In addition, these companies may have a greater ability to continue drilling, production and workover activities during periods of low natural gas and NGL prices, to contract for drilling, production and workover equipment, to pay more for and secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The natural gas, NGL and oil industry has periodically experienced shortages of drilling rigs, equipment, hydraulic fracturing fleets, supply chain resources, pipelines and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the engineering and technical, accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive natural gas, NGL and oil producing properties, natural gas, NGL and oil companies, undeveloped leases and drilling rights, and CCUS projects. Further, the current inflation may affect us more than it may affect some of our larger competitors. Our inability to compete effectively with our competitors could have a material adverse impact on our business activities, financial condition and results of operations.

The energy industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. Further, competitors may obtain patents which might prevent us from implementing new technologies. In addition, other energy companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

The inability of one or more of our significant counterparties to meet their payment or performance obligations may adversely affect our financial results.

We are subject to certain credit risks associated with nonpayment or nonperformance by our counterparties, including joint interest partners and customers. Joint interest receivables arise from billing our joint interest partners who own a partial working interest in our natural gas and NGL wells. These entities participate in our natural gas and NGL wells primarily based on their ownership in leases on which we operate, and we have limited ability to control their participation in our natural gas and NGL wells. Sales receivables arise from the sale of our natural gas and NGL production to our customers. We currently market, directly or indirectly, our natural gas and NGL production to energy marketing companies, refineries, gas processors, petrochemical companies, local distribution companies, power plants and other end users.

We maintain credit procedures and policies to mitigate the credit risks posed by our counterparties. However, our credit procedures and policies may not be adequate to fully eliminate the risk and we do not require all of our counterparties to post collateral. If we fail to adequately assess the creditworthiness of our existing or future significant counterparties, or their creditworthiness unexpectedly materially deteriorates, any resulting nonpayment or nonperformance by them could have a materially adverse effect on our financial condition, results of operations and ability to pay dividends on our common stock.

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

Our businesses face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. Security breaches could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, cash flows and ability to pay dividends on our common stock. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. The risk of a cybersecurity attack may increase as a result of the increased volume of "remote" work due to workplace policy changes resulting from the spread of COVID-19. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

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

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

- delay or denial of drilling permits;
- shortening of lease terms and reduction in lease size;
- restrictions on installation or operation of production, gathering or processing facilities;

- restrictions on the use of certain operating practices, such as hydraulic fracturing, or disposal of related waste materials, such as hydraulic fracking fluids and production;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about our business or the natural gas, NGL and oil industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

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

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

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

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

Like many energy companies, in the ordinary course of our business, we are from time to time involved in various disputes and disagreements that may lead to legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, prospects, financial condition, results of operations, cash flows and ability to pay dividends on our common stock. 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 materially change from one period to the next.

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

We are heavily dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell natural gas and NGLs 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.

We are highly dependent on our executive officers and technical personnel, the loss of any of whom could adversely affect our operations. Additionally, the continued success of our business depends on our ability to attract and retain experienced technical personnel.

We depend on the services of our senior management and technical personnel. There can be no assurance that we would be able to replace such members of management with comparable replacements or that such replacements would integrate well with our existing team. Further, the loss of the services of our senior management could have a material adverse effect on our business, financial condition and results of operations. We do not maintain, nor do we plan to obtain, any "key-man" life insurance against the loss of any of these individuals. As a result, we are not insured against any losses resulting from the death of our key employees. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, prospects, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Our continued success will depend, in part, on our ability to attract and retain experienced technical personnel, including geologists, engineers and other professionals. Competition for these professionals is strong and will likely intensify as a significant portion of today's engineers, geologists and other professionals working within the oil and natural gas industry will reach the age of retirement in the coming years. Acquiring and retaining these personnel could prove more difficult or cost substantially more than estimated.

Risks Related to Environmental, Legal Compliance and Regulatory Matters

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our natural gas and NGL exploration and production operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or drilling and related permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling and related permits with onerous conditions could increase our compliance costs or decrease our opportunities to execute projects and develop acreage. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of natural gas and NGLs we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of natural gas and NGLs. The possibility exists that new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs or cause us to cease operations. If we are not able to recover the resulting costs through insurance or increased revenues, our financial condition and ability to pay dividends on our common stock could be adversely affected.

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

Increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG initiatives and disclosures and consumer demand for alternative forms of energy may result in increased costs (including, but not limited to, increased costs related to compliance, stakeholder engagement, contracting and insurance), reduced demand for our products, reduced profits, increased investigations and litigation and negative impacts on our access to capital markets. Increasing attention to climate change, environmental justice and environmental conservation, for example, may result in demand shifts for natural gas, NGL and oil products and additional governmental investigations and private litigation against us. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. Such disclosures may also be at least partially reliant on third-party information that we have not verified, or cannot verify, independently. In addition, we expect there will likely be increasing levels of regulation, disclosure-related and otherwise, with respect to ESG matters, and increased regulation will likely lead to increased compliance costs as well as scrutiny that could heighten all of the risks identified in this risk factor. We may also take certain actions to improve the ESG profile of our company and/or products, but we cannot guarantee that such actions will have the desired effect.

In addition, we note that standards and expectations regarding carbon accounting and the processes for measuring and counting GHG emissions and GHG emission reductions are evolving, and it is possible that our approach to measuring both our emissions and our approaches to reducing emissions may be, either currently by some stakeholders or at some future point, considered inconsistent with common or best practices with respect to measuring and accounting for such matters, reducing overall emissions and/or achieving “net zero.” If our approaches to such matters fall out of step with common or best practice, we may be subject to additional scrutiny, criticism, regulatory and investor engagement or litigation, any of which may adversely impact our business, financial condition or results of operations.

Additionally, in March 2022, the SEC proposed a new rule relating to the disclosure of a range of climate-related data, risks and opportunities. We are currently assessing this rule, but we cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. To the extent this rule is finalized as proposed or as may be revised, we or our customers could incur increased costs related to the assessment and disclosure of climate-related risks. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon intensive sectors.

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 and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change and natural capital related concerns, which could affect our access to capital for potential growth projects. Moreover, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees. Such ESG matters may also impact our suppliers or customers, which may adversely impact our business, financial condition, or results of operations.

Energy conservation measures and technological advances could reduce demand for natural gas, NGL and oil.

Energy conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to natural gas, NGL and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas, NGLs and oil. The impact of the changing demand for natural gas, NGL and oil services and products may have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes, droughts and floods), sea levels, the arability of farmland, changes in temperature and other meteorological patterns, and water availability and quality. If such effects were to occur, our development and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate related damages to our facilities or in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. We have developed and started to implement a plan to address the potential impacts of climate change on our operations, but we cannot assure you that our operations will not be negatively impacted by climate change.

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

Hydraulic fracturing is used in many of our operations to stimulate production of hydrocarbons, particularly natural gas and NGLs. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production. The U.S. Congress (“Congress”) from time to time has considered legislation to amend the federal Safe Drinking Water Act (“SDWA”) to remove the exemption currently available to hydraulic fracturing, which would place additional regulatory burdens upon hydraulic fracturing operations, including requirements to obtain a permit prior to commencing operations adhering to certain construction requirements, to establish financial assurance, and to require reporting and disclosure of the chemicals used in those operations. This legislation has not passed.

Hydraulic fracturing (other than that using diesel) is currently generally exempt from regulation under the SDWA’s UIC program and is typically regulated by state oil and natural gas commissions or similar agencies. However, several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the process.

For example, in June 2016, the EPA adopted effluent limitations for the treatment and discharge of wastewater resulting from onshore unconventional natural gas, NGL and oil extraction facilities to publicly owned treatment works and, in 2014, the EPA asserted regulatory authority pursuant to the UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities.

Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances.” The final report identified the following risks: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. To date, EPA has taken no further action in response to the December 2016 report.

In addition, some states have adopted, and other states are considering adopting, regulations that restrict or could restrict hydraulic fracturing in certain circumstances. Further, state and local governmental entities have exercised the regulatory powers to regulate, curtail or in some cases prohibit hydraulic fracturing. 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, liquidity and ability to pay dividends on our common stock.

Regulatory action may cause us to shut in or curtail production.

Our rate of production and access to transportation and storage options may also be affected by U.S. federal and state regulation of oil and natural gas production. In 2020, actions of foreign oil producers such as Saudi Arabia and Russia and the impact on global demand of the COVID-19 pandemic materially decreased global crude oil prices and generated a surplus of oil. As a result, regulatory action to curtail production has been contemplated in Texas. For example, the TRRC, which regulates the production of oil and natural gas in the State of Texas, held a hearing in April 2020 regarding potential production cuts for producers in Texas in light of the recent decline in oil prices globally. While the TRRC ultimately declined to institute mandatory production cuts, the agency may choose to revisit the issue. Global and domestic oil prices have recovered substantially to the point that TRRC curtailments are highly unlikely. However, if the TRRC decides to limit the production of crude oil in Texas in the future, our business and results of operations are not likely to be materially and adversely impacted given that our production comes from dry gas wells.

Any such production limitations will likely force us to shut in production. If we are forced to shut in production as a result of regulatory actions or otherwise, we will likely incur greater costs to bring the associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in our proved reserve estimates and potential impairments and associated charges to our earnings. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut in. Any shut in or curtailment of the natural gas and NGLs produced from our fields could adversely affect our financial condition, results of operations, cash flows, ability to pay dividends on our common stock and ability to fulfill our obligations under our firm transportation service agreements.

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

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of carbon dioxide, methane and other GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, President Biden has highlighted addressing climate change as a priority of his administration and has issued several executive orders addressing climate change. In August 2022, Congress passed, and President Biden signed into law, the Inflation Reduction Act of 2022, which imposes several new climate-related requirements on oil and gas operations and appropriates significant federal funding for renewable energy initiatives. The Inflation Reduction Act, for the first time ever, imposes a fee on GHG emissions from certain facilities. The emissions fee and funding provisions of the law could increase our operating costs and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations.

Moreover, following the U.S. Supreme Court finding in 2007 that GHG emissions constitute a pollutant under the CAA, the EPA adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, and together with the U.S. Department of Transportation (“DOT”), imposing GHG emissions and fuel economy standards for vehicles in the United States. The regulation of methane from oil and gas facilities has been subject to uncertainty in recent years. The EPA previously had promulgated New Source Performance Standards (“NSPS”) imposing limitations on methane emissions from sources in the oil and gas sector. Subsequently, in September 2020, the Trump Administration rescinded those methane standards and removed the transmission and storage segments from the oil and gas source category under the CAA’s NSPS. However, on June 30, 2021, President Biden signed a resolution passed by Congress under the Congressional Review Act nullifying the September 2020 rule, effectively reinstating the prior standards. In addition, on November 15, 2021, the EPA proposed rules that would establish requirements for methane emissions from existing and modified oil and gas sources and impose additional requirements for new sources with respect to methane emissions (“2021 Proposed Methane Rules”). On November 11, 2022, the EPA issued a supplemental proposal to update, strengthen and expand the 2021 Proposed Methane Rules that would make the proposed requirements more stringent and include sources not previously regulated under the oil and gas source category. The EPA has announced that it intends to finalize these rulemakings in 2023. The reinstatement of direct regulation of methane emission for new sources, promulgation of requirements for existing oil and gas sources and enhanced requirements for new sources, and the expansion of sources covered by the EPA's rules, could result in increased compliance costs or otherwise impact our results of operations.

Various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. For example, several states, including Pennsylvania and New Mexico, have proposed or adopted regulations restricting the emission of methane from exploration and production activities. At the international level, President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' economy-wide GHG emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change ("COP26"), during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-CO_2 GHGs. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. President Biden also agreed in November 2021 to cooperate with Chinese leader Xi Jinping on accelerating the transition to a global net zero economy. The impacts of these pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, or other international conventions cannot be predicted at this time. However, to the extent these developments result in new restrictions on natural gas and NGL operations, increase operational costs, or otherwise reduce the demand for natural gas and NGLs, they could have a material adverse effect on our business.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates now in public office. On January 27, 2021, President Biden issued an executive order that calls for substantial action on climate change, including, among other things, the increased use of zero-emission vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across government agencies and economic sectors. The Biden Administration also issued orders temporarily suspending the issuance of authorizations, and suspending the issuance of new leases pending a study, for oil and gas development on federal lands, although such orders are no longer in effect. For more information, see "*Business — Government Regulation and Environmental Matters*." As a result, we cannot predict the full impact of these developments or whether the Biden Administration may pursue further restrictions. Other actions that could be pursued by the Biden Administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emission limitations for oil and gas facilities.

Increasing attention to global climate change has resulted in increased investor attention and an increased risk of public and private litigation, which could increase our costs or otherwise adversely affect our business. A number of parties have sought to bring suit against the largest oil and gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing, handling or marketing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts. The ultimate outcome and impact to us of any such litigation cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future. Stockholder activism has also recently been increasing in our industry, and stockholders may attempt to effect changes to our business or governance, whether by stockholder proposals, public campaigns, proxy solicitations or otherwise. Any of these risks could result in unexpected costs, negative sentiments about us, disruptions in our operations, increases to our operating expenses and reduced demand for our products, which in turn could have an adverse effect on our business, financial condition and results of operations.

There are also increasing financial risks for fossil fuel producers as stockholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. President Biden signed an executive order calling for the development of a "climate finance plan" and, separately, the Federal Reserve has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. In November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Additionally, in March 2022, the SEC proposed a new rule relating to the disclosure of a range of climate-related data, risks and opportunities. The proposed rule would impose several new disclosure obligations, including (i) disclosure on an annual basis of a registrant's Scope 1 and Scope 2 GHG emissions, with third-party independent attestation of such emissions for accelerated filers, (ii) disclosure on an annual basis of a registrant's Scope 3 GHG emissions for accelerated filers, (iii) disclosure on how the board of directors and management oversee climate-related risks and certain climate-related governance items, (iv) disclosure of information related to a registrant's publicly announced climate-related targets, goals and/or transition plans and (v) disclosure on whether and how climate-related events and transition activities impact line items above a threshold amount on a registrant's consolidated financial statements, including the impact of the financial estimates and the assumptions used. We are currently assessing this rule, but we cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. To the extent this rule is finalized as proposed or as may be revised, we or our customers could incur increased costs related to the assessment and disclosure of climate-related risks. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon intensive sectors. The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and gas sector or otherwise restrict the areas in which this sector may produce oil and gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

Our ability to pursue our business strategies may be adversely affected if we incur costs and liabilities due to a failure to comply with environmental, health and safety laws or regulations or a release into the environment.

We may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of our wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental, health and safety laws and regulations, including, for example, the following federal laws and their state counterparts, as amended from time to time:

- the CAA, which regulates the emission of air pollutants from many sources, imposes various preconstruction, monitoring and reporting requirements and is relied upon by the EPA as authority for adopting climate change regulatory initiatives relating to GHG emissions;
- the Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA"), which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterbodies are subject to federal jurisdiction and rulemaking as protected waters of the United States;

- the SDWA, which is designed to protect the quality of the nation's public drinking water through adoption of drinking water standards and UIC over the subsurface injection of fluids into belowground formations;
- the federal Resource Conservation and Recovery Act, as amended ("RCRA"), which imposes requirements for the generation, treatment, storage, transport, disposal and cleanup of nonhazardous and hazardous wastes;
- the federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), which imposes liability on generators, and those who arrange for the transportation, treatment or disposal, of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur as well as on present and certain past owners and operators of those sites;
- the Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees and response departments about toxic chemical uses and inventories; and
- the Endangered Species Act ("ESA"), which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating limitations or restrictions or a temporary, seasonal or permanent ban on operations in affected areas.

These U.S. laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water and disposals or other releases or threats of release to surface, soils and groundwater. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the incurrence of capital expenditures, the occurrence of delays in the permitting, development or expansion of projects and the issuance of orders enjoining some or all of our future operations in a particular area. Certain environmental laws impose strict joint and several liability, without regard to fault or legality of conduct, for costs required to clean up and restore sites where hazardous substances or other wastes have been disposed of or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, wastes or other materials into the environment. In addition, these laws and regulations may restrict the rate of natural gas and NGL production or underground injection, disposal, and sequestration of CO_2. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

In addition, as a result of these environmental, health and safety laws and regulations, and their impact on our operations, we rely on specialized contracted companies to perform the majority of the specialized services inherent in the oil and gas industry. As such, we rely on the ability of these contractors to provide trained labor and properly designed and maintained equipment unique to their services. With the cyclical nature of the oil and gas business, the personnel used by these specialized contractors to perform these services may differ significantly in experience levels. From time to time, these specialized contractors may use new personnel that are still in training or may further sub-contract these services to other companies or personnel. There is a risk that these sub-contractors are unqualified or under-trained or that their equipment is not properly designed or maintained, which could result in work being performed inadequately or unsafely.

Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or production 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.

Our gathering systems and processing, treating and fractionation facilities are subject to state regulation that could have a material adverse effect on our operations and cash flows.

State regulation of gathering systems and processing, treating and fractionation facilities includes safety and environmental requirements. In addition, several of our gas gathering systems are also subject to non-discriminatory take requirements and complaint-based state regulation with respect to our rates and terms and conditions of service. Our NGL gathering pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities. State and local regulation may cause us to incur additional costs, limit our operations, or prevent us from choosing the customers to which we provide service, any or all of which could have a material adverse effect on our operations and revenue.

Temple I is subject to the rules and regulations of the PUCT and ERCOT, which could have a material adverse effect on our operations and cash flows.

Temple I is subject to the rules and regulations of the PUCT and ERCOT. These regulations can impact the operations of generation facilities, which in turn can impact associated costs and revenues. For example, the PUCT implemented rules regarding weatherization of power plants in the aftermath of Winter Storm Uri. Such rules increased capital and operations and maintenance costs for many generation facilities. Additionally, the PUCT is currently weighing a redesign of the ERCOT market that is intended to retain existing generation facilities and encourage the construction of new generation facilities. This process could lead to decreased revenue, increased operating costs, and adversely affect our business, financial condition, and results of operations.

In addition, from time to time, ERCOT makes changes to its protocols or takes out of market actions that impact the wholesale power market. These regulations may cause us to incur additional costs or face delays, or otherwise could have a material adverse effect on our operations and cash flows.

We may face unanticipated water and other waste disposal costs as a result of increased water-related regulations.

We may be subject to regulation that restricts our ability to discharge water produced as part of our natural gas and NGL production operations. Productive zones frequently contain water that must be removed for the natural gas and NGLs to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce natural gas and NGLs in commercial quantities. The produced water must be transported from the leasehold and/or injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability. Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

In June 2016, the EPA adopted effluent limitations for the treatment and discharge of wastewater resulting from onshore unconventional natural gas, NGL and oil extraction facilities to publicly owned treatment works. The disposal of fluids gathered from natural gas, NGL and oil producing operations in underground disposal wells has been pointed to by some groups and regulators as a potential cause of increased induced seismic events in certain areas of the country, particularly in Oklahoma, Texas, Colorado, Kansas, New Mexico and Arkansas. Certain states have begun to consider or adopt laws and regulations that may restrict or otherwise prohibit oilfield fluid disposal in certain areas or underground disposal wells, and state agencies implementing those requirements may issue orders directing certain wells in areas where seismic incidents have occurred to restrict or suspend disposal well operations or impose standards related to disposal well construction and monitoring. Any one or more of these developments could also increase our cost to dispose of our produced water.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering operations are generally exempt from the jurisdiction and regulation of the Federal Energy Regulatory Commission ("FERC"), except for certain anti-market manipulation provisions. Section 1(b) of the Natural Gas Act ("NGA") exempts natural gas gathering facilities from regulation by FERC as a natural gas company as defined under that statute. We believe the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gathering pipeline not subject to regulation by FERC. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is fact intensive and the subject of ongoing litigation. If FERC were to consider the status of our gathering systems and determine that they are subject to FERC regulation, the rates for, and terms and conditions of, services provided by those gathering systems would be subject to modification by FERC under the NGA or the Natural Gas Policy Act ("NGPA"). Such regulation could decrease revenue, increase operating costs, and adversely affect our business, financial condition, and results of operations. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, it could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such services in excess of the rates established by FERC.

The pipelines used to gather and transport natural gas we produce are subject to regulation by the DOT under the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Act of 1992, as reauthorized and amended, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"). 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. In April 2016, pursuant to one of the requirements of the 2011 Pipeline Safety Act, PHMSA published a proposed rulemaking that would expand integrity management requirements and impose new pressure testing requirements on currently regulated gas gathering and transmission pipelines. The proposal would also significantly expand the regulation of gas gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, and maximum allowable operating pressure limits, among others. In October 2019, PHMSA submitted three major rules to the Federal Register, including rules focused on: the safety of gas transmission pipelines (the first of three parts of the so-called "Gas Mega Rule"), the safety of hazardous liquid pipelines and enhanced emergency order procedures. The gas transmission rule requires operators of gas transmission pipelines constructed before 1970 to determine the material strength of their lines by reconfirming the maximum allowable operating pressure. In addition, the rule updates reporting and records retention standards for gas transmission pipelines.

The final of the three components of the Gas Mega Rule was published on August 24, 2022, to become effective on May 24, 2023. The Gas Mega Rule imposes new standards for pipeline inspections and repairs and empowers PHMSA with expanded authority to issue emergency orders.

The adoption of laws or regulations that apply more comprehensive or stringent safety standards could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operating costs that could be significant. In addition, should we fail to comply with PHMSA or comparable state regulations, we could be subject to substantial fines and penalties. As of January 2023, the maximum civil penalties PHMSA can impose are $257,664 per pipeline safety violation per day, with a maximum of $2,576,627 for a related series of violations.

Restrictions on drilling, completion, production or related activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Natural gas and NGL operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife, such as those restrictions imposed under the ESA. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, development and production activities that could have an adverse impact on our ability to develop and produce our reserves. To the extent species are listed or re-designated under the ESA or similar state laws, or previously unprotected species are designated as threatened or endangered in areas where our properties are located, operations on those properties could incur increased costs arising from species protection measures and face delays or limitations with respect to production activities thereon. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us to incur costs or take other measures which may materially impact our business or operations.

Potential transactions that could benefit our stockholders may be subject to regulatory review and approval requirements, including pursuant to foreign investment regulations and review by governmental entities such as the Committee on Foreign Investment in the United States ("CFIUS"), or may be ultimately prohibited.

Potential transactions we consider may be subject to regulatory review and approval requirements by governmental entities, or ultimately prohibited. For example, CFIUS has authority to review direct or indirect foreign investments in U.S. companies. Among other things, CFIUS is empowered to require certain foreign investors to make mandatory filings, to charge filing fees related to such filings, and to self-initiate national security reviews of foreign direct and indirect investments in U.S. companies if the parties to that investment choose not to file voluntarily. In the case that CFIUS determines an investment to be a threat to national security, CFIUS has the power to unwind or place restrictions on the investment. Whether CFIUS has jurisdiction to review an acquisition or investment transaction depends on, among other factors, the nature and structure of the transaction, including the level of beneficial ownership interest and the nature of any information or governance rights involved. For example, investments that result in "control" of a U.S. business by a foreign person always are subject to CFIUS jurisdiction. CFIUS's expanded jurisdiction under the Foreign Investment Risk Review Modernization Act of 2018 and implementing regulations that became effective on February 13, 2020 further includes investments that do not result in control of a U.S. business by a foreign person but afford certain foreign investors certain information or governance rights in a U.S. business that has a nexus to "critical technologies," "critical infrastructure" and/or "sensitive personal data."

For so long as Banpu retains a material ownership interest in us, we may be deemed a "foreign person" under the regulations relating to CFIUS. As such, potential transactions involving a U.S. business or foreign business with U.S. subsidiaries that we may wish to pursue may be subject to CFIUS review. If a particular transaction falls within CFIUS's jurisdiction, we may determine that we are required to make a mandatory filing or that we will submit to CFIUS review on a voluntary basis, or to proceed with the transaction without submitting to CFIUS and risk CFIUS intervention, before or after closing the transaction. CFIUS may decide to block or delay transactions that could benefit our stockholders, impose conditions with respect to such transactions or request the President of the United States to order us to divest all or a portion of the assets or companies we acquired without first obtaining CFIUS approval, which may limit the attractiveness of, delay or prevent us from pursuing certain target companies or assets that we believe would otherwise be beneficial to us and our stockholders, any of which could have a material adverse effect on our financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Our sales of natural gas and NGLs, and any hedging activities related to such commodities, expose us to potential regulatory risks.

Sales of natural gas and NGLs are not currently regulated and are made at negotiated prices. However, the federal government historically has been active in the area of natural gas and NGL sales regulation. We cannot predict whether new legislation to regulate natural gas and NGL sales might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on our operations.

Additionally, the Federal Trade Commission and the Commodity Futures Trading Commissions (the "CFTC") hold statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of natural gas and NGLs, and any hedging activities related to these energy commodities, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

The adoption of derivatives legislation and regulations by Congress related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of over-the-counter ("OTC") derivatives and requires the CFTC and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized.

In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on December 5, 2016, a re-proposed rule imposing position limits for certain futures and option contracts in various commodities (including natural gas, NGL and oil) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of hedging transactions are exempt from these limits on the size of positions that may be held, provided that such hedging transactions satisfy the CFTC's requirements for certain enumerated "bona fide hedging" transactions or positions. A final rule has not yet been issued. Similarly, on December 2, 2016, the CFTC has reissued a proposed rule regarding the capital a swap dealer or major swap participant is required to set aside with respect to its swap business, but the CFTC has not yet issued a final rule.

The CFTC has also adopted final rules regarding aggregation of positions, under which a party that controls the trading of, or owns 10% or more of the equity interests in, another party will have to aggregate the positions of the controlled or owned party with its own positions for purposes of determining compliance with position limits unless an exemption applies. The CFTC's aggregation rules are now in effect, though CFTC staff have granted relief from various conditions and requirements in the final aggregation rules until the earlier of August 12, 2025 and the effective date of any rulemaking that codifies the relief. With the implementation of the final aggregation rules and upon the adoption and effectiveness of the final CFTC position limits rules, our ability to execute our hedging strategies described above could be limited. It is uncertain at this time whether, when and in what form the CFTC's proposed new position limits rules may become final and effective.

The CFTC issued a final rule on margin requirements for uncleared swap transactions on January 6, 2016, which includes an exemption from any requirement to post margin to secure uncleared swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business. In addition, the CFTC has issued a final rule authorizing an exemption from the otherwise applicable mandatory obligation to clear certain types of swap transactions through a derivatives clearing organization and to trade such swaps on a regulated exchange, which exemption applies to swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business. The mandatory clearing requirement currently applies only to certain interest rate swaps and credit default swaps, but the CFTC could act to impose mandatory clearing requirements for other types of swap transactions. The

Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations.

All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business. While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements, depending on our ability to satisfy the CFTC's requirements for a commercial end-user using swaps to hedge or mitigate our commercial risks, these rules and regulations may require us to comply with position limits and with certain clearing and trade-execution requirements in connection with our financial derivative activities. When a final rule on capital requirements for swap dealers is issued, the Dodd-Frank Act may require our current swap dealer counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which capital requirements rule could increase the costs to us of future financial derivatives transactions. The Volcker Rule provisions of the Dodd-Frank Act may also require our current bank counterparties that engage in financial derivative transactions to spin off some of their derivatives activities to separate entities, which separate entities may not be as credit-worthy as the current bank counterparties. Under such rules, other bank counterparties may cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of entities like us, as commercial end-users, to have access to financial derivatives to hedge or mitigate our exposure to commodity price volatility.

As a result, the Dodd-Frank Act and any new regulations issued thereunder could significantly increase the cost of derivative contracts (including through requirements to post cash collateral), which could adversely affect our capital available for other commercial operations purposes, materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts and reduce the availability of derivatives to protect against commercial risks we encounter.

If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of commodity prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to natural gas, NGLs and oil. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

Potential future legislation or the imposition of new or increased taxes or fees may generally affect the taxation of natural gas, NGL and oil exploration and development companies and may adversely affect our cash flows.

Since 2020, there have been a significant number of federal and state level legislative proposals that, if enacted into law, would make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to natural gas, NGL and oil exploration and development companies. For example, in late 2021 the U.S. House of Representatives passed legislation that was not ultimately enacted and, in early 2022, the Biden administration set forth several tax proposals, that would, if ultimately enacted into law, make significant changes to U.S. tax laws. Such proposals include, but are not limited to, (i) an increase in the U.S. federal income tax rates applicable to corporations, (ii) the repeal of the percentage depletion allowance for certain natural gas, NGL and oil properties, (iii) the elimination of current deductions for intangible drilling and development costs and (iv) an increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas, NGL and oil within the United States. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, the states in which we operate or own assets may impose new or increased taxes or fees on natural gas, NGL and oil extraction. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws or the imposition of new or increased taxes or fees on natural gas, NGL and oil extraction could adversely affect our operations and cash flows.

Our tax liabilities potentially are subject to periodic audits by U.S. federal, state and local taxing authorities. Although we believe we have used reasonable interpretations and assumptions in calculating our tax liabilities, the final determination of these tax audits and any related proceedings cannot be predicted with certainty. Any adverse outcome of any such tax audits or related proceedings could result in unforeseen tax-related liabilities that may, individually or in the aggregate, materially affect our cash tax liabilities, and, as a result, our business, financial condition, results of operations, and liquidity.

Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy and the unauthorized disclosure of personal or confidential information pose increasingly complex compliance challenges and could potentially elevate our costs. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. We continue to monitor and assess the impact of these laws, which in addition to penalties and legal liability, could impose significant costs for investigations and compliance, require us to change our business practices and carry significant potential liability for our business should we fail to comply with any such applicable laws.

Risks Related to Our Relationship with Banpu and its Affiliates

Banpu is our controlling stockholder and exercises substantial influence over us, and your ability to influence matters requiring stockholder approval may be limited.

Upon completion of this offering, Banpu will indirectly own approximately % of our outstanding common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares). Our outstanding common stock is entitled to one vote per share. As a result of its ownership of our common stock, Banpu will indirectly own approximately % of the combined voting power of our common stock immediately after completion of this offering (or approximately % if the underwriters exercise in full their option to purchase additional shares). As a result of this ownership, Banpu has a substantial influence on our affairs and its voting power will constitute a substantial percentage of any quorum of our stockholders voting on any matter requiring the approval of our stockholders. Such matters include the election of directors, the adoption of amendments to our certificate of incorporation and bylaws and the approval of mergers or the sale of all or substantially all of our assets. Banpu’s control or significant influence over us also may delay, defer or prevent an acquisition by a third party or other change of control of our Company and may make some transactions more difficult or impossible without the support of Banpu, even if such events are in the best interests of our other stockholders.

In addition, pursuant to our Stockholders’ Agreement, for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that (i) from the completion of this offering until the first anniversary of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. See “*Management — Controlled Company*,” “*Principal Stockholders”* and “*Certain Relationships and Related Party Transactions — Stockholders’ Agreement*.”

In addition, we do not control the BKV-BPP Power Joint Venture. We and BPPUS jointly control BKV-BPP Power through a board of directors consisting of eight members, four of which are appointed by us and four of which are appointed by BPPUS. See “*— Risks Related to Our Power Generation Business — We operate our power generation business through a joint venture which we do not control.*” Further, if, after this initial public offering, Banpu and its wholly owned subsidiaries cease to own at least 51% of our equity interests, or if any such holder allows any lien to exist on our equity interests that they own, such event will be an event of default under the Term Loan Credit Agreement and the Revolving Credit Agreement, which may result in the amounts owed by us thereunder to become immediately due and payable.

The interests of Banpu may differ from our interests or those of our other stockholders and the concentration of control in Banpu will limit other stockholders’ ability to influence corporate matters.

Banpu may take actions that our other stockholders do not view as beneficial or decline to take actions that our other stockholders view as beneficial, which may adversely affect our business, financial condition, results of operations and our ability to pay dividends on our common stock. In addition, Banpu's control or significant influence over us may have an adverse effect on the price of our common stock.

Historically we have relied on Banpu and its affiliates for capital investments sufficient to fund our business operations. Banpu has no obligation to make any further capital investments or to provide additional loan proceeds.

Prior to the consummation of this offering, we have relied on Banpu and its affiliates for the capital investments necessary to fund our business through loan proceeds and other contributions. Following this offering, Banpu and its affiliates will have no obligation to provide any additional funding, and instead, we expect to fund our capital expenditures for our upstream, midstream and power businesses through cash flows from operations and from borrowings under our Revolving Credit Facilities and the Revolving Credit Agreement. We expect to fund our CCUS business with a combination of cash flows from operations and funding from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants. Our future operating performance and to meet our debt service obligations will be affected by economic and capital market conditions, commodity prices, our results of operations and other factors, many of which are beyond our control.

Restrictive covenants in the agreements governing the indebtedness of Banpu may limit our ability to incur additional debt.

The agreements governing the indebtedness of Banpu require it to maintain certain financial ratios and tests based on consolidated financial statements. Immediately after completion of this offering, Banpu, or a subsidiary of Banpu, will continue to have a substantial influence on our affairs and its voting power will constitute a substantial percentage of any quorum of our stockholders voting on any matter requiring the approval of our stockholders. As a result, Banpu may prevent us from taking corporate actions that could cause Banpu to fail to comply with the applicable provisions of its debt agreements, even when such actions are in our best interests and the interests of our other stockholders. This limitation may materially adversely affect our ability to obtain future financing or fund needed capital expenditures.

We expect to be a "controlled company" within the meaning of the NYSE rules and, as a result, will qualify for and could rely on exemptions from certain corporate governance requirements.

Upon the completion of this offering, Banpu will beneficially control a majority of the combined voting power of all classes of our outstanding voting stock. Pursuant to our Stockholders' Agreement, BNAC, through ownership interests in us held by BNAC and its affiliates, will have certain rights to designate individuals for nomination to our board of directors. "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*" contains additional information regarding these risks. As a result, we expect to be a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the corporate governance and nominating committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and governance and compensation committees.

These requirements will not apply to us as long as we remain a controlled company. Following this offering, we may utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. "*Management — Controlled Company*" contains additional information regarding these risks.

Banpu's interests, including interests in certain corporate opportunities, may conflict with our interests and the interests of our other stockholders. Conflicts of interest between us and Banpu could be resolved in a manner unfavorable to us and our other stockholders.

Banpu could have interests that differ from, or conflict with, the interests of our other stockholders and could cause us to take certain actions even if the actions are not favorable to us or our other stockholders or are opposed by our other stockholders. Potential conflicts of interest or disputes may arise between Banpu and us in a number of areas relating to our past or ongoing relationships, including:

- tax, employee benefits, indemnification and other matters arising from this offering;
- employee retention and recruiting;
- corporate opportunities that may be attractive to both Banpu and us;
- the arrangements governing the BKV-BPP Power Joint Venture and any other new commercial arrangements between the Company and affiliates of Banpu in the future; and
- sales or other disposals by Banpu of all or a portion of its interest in us.

We may not be able to resolve potential conflicts and disputes with Banpu and even if we do, the resolution may be less favorable to us than if we were dealing with an unaffiliated third party. Because we are controlled or significantly influenced by Banpu, we may not have the leverage to negotiate amendments to the arrangements governing the BKV-BPP Power Joint Venture (if any are required) on terms as favorable to us as those we would negotiate with an unaffiliated third party.

Additionally, there can be no assurance that Banpu will not engage in competition with us in the future. Our certificate of incorporation provides that, to the fullest extent permitted by law, neither Banpu nor its affiliates or any director who is not employed by us (including any non-employee director who serves as one of our officers in both his or her director and officer capacities) or his or her affiliates will have any duty to refrain from (i) engaging in the same or similar business activities or lines of business in which we or our affiliates now engage or propose to engage or (ii) otherwise competing with us or our affiliates. In addition, to the fullest extent permitted by law, in the event that Banpu or its affiliates or any non-employee director acquires knowledge of a potential transaction or other business opportunity that may be a corporate opportunity for itself, himself or herself or its or his or her affiliates or for us or any of our affiliates, such person will have no duty to communicate or offer such transaction or business opportunity to us or any of our affiliates and they may take any such opportunity for themselves or offer it to another person or entity.

Our certificate of incorporation also renounces, to the fullest extent permitted by law, any interest or expectancy that we have in, or right to be offered an opportunity to participate in, specified business opportunities that are from time to time presented to our officers, directors or stockholders or their respective affiliates, other than those officers, directors, stockholders or affiliates who are our or our subsidiaries' employees.

Generally, neither Banpu nor our non-employee directors who also are directors, officers, employees, agents or affiliates of Banpu or its affiliates (other than us) will be liable to us or our stockholders for breach of any fiduciary duty solely by reason of the fact that any such person pursues or acquires any corporate opportunity for, or recommends or transfer any corporation opportunity to, Banpu or its affiliates (other than us), rather than to us. This renunciation will not extend to corporate opportunities expressly offered to one of our non-employee directors solely in his or her capacity as our director or officer.

These provisions create the possibility that a corporate opportunity of our Company may be used for the benefit of Banpu and may significantly impair our ability to grow.

Certain of our directors may have actual or potential conflicts of interest because of their positions with Banpu and/or their ownership of common stock or equity awards in Banpu.

Following this offering, six of our directors will be employees of Banpu or its affiliates. In addition, such directors may own capital stock or equity awards in Banpu. For certain of these individuals, their holdings of common stock or equity awards in Banpu may be significant compared to their total assets. Their position at Banpu or its affiliates and the ownership of capital stock or equity awards in Banpu creates, or may create the appearance of, conflicts of interest when these directors and officers are faced with decisions that could have different implications for Banpu than for us. These decisions could include:

- corporate opportunities;
- the impact that operating or capital decisions (including the incurrence of indebtedness) relating to our business may have on Banpu's consolidated financial statements or current or future indebtedness (including related covenants);
- business combinations involving us;
- our dividend and stock repurchase policies;
- compensation and benefit programs and other human resources policy decisions;
- management stock ownership;
- the payment of dividends on our common stock; and
- determinations with respect to our tax returns.

As a result of these actual or apparent conflicts of interest, we may be precluded from pursuing certain growth initiatives or transactions that may be favorable to us or we may take certain actions even if the actions are not favorable to us or are opposed by our stockholders.

If Banpu experiences a change in control, you may not realize any change-of-control premium on shares of our common stock and we may become subject to the control of a presently unknown third party. Further, Banpu may sell, or pledge as collateral for its existing or future indebtedness, the shares of our common stock that it owns.

After this offering, Banpu will own approximately % of our outstanding common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares). Subject to the provisions of the lock-up agreement entered into in connection with this offering, Banpu will not be restricted from selling some or all of its shares of our common stock in a privately negotiated transaction or otherwise, and a sale of its shares, if sufficient in size, could result in a change of control of our Company. Further, Banpu will not be restricted from pledging as collateral for its indebtedness the shares of our common stock held by it.

The ability of Banpu to sell its shares of our common stock, with no requirement for a concurrent offer to be made to acquire all of the shares of our common stock held by our other stockholders, could prevent you from realizing any change-of-control premium on your shares of our common stock that may otherwise accrue to Banpu on its sale of our common stock. In addition, if Banpu were to pledge as collateral for its indebtedness the shares of our common stock held by it, and Banpu were to default under such indebtedness, the lenders thereunder could foreclose upon and sell such shares to satisfy Banpu's obligations under such indebtedness.

Further, any acquiror or successor of all or a substantial number of Banpu's shares of our common stock will be entitled to exercise Banpu's voting control with respect to us. Such third party may have interests that conflict with those of our other stockholders. Any acquiror or successor to which Banpu transfers a controlling interest in us may attempt to cause us to revise or change our plans and strategies, as well as the agreements between Banpu and us described in this prospectus.

Risks Related to the Offering and Our Common Stock

Our actual operating results and activities could differ materially from the guidance we have disclosed herein.

We have presented herein certain forecasted operating results, costs and activities, including, without limitation, our future expected drilling activity and production. Any such forward-looking guidance represents our management's estimates as of the date hereof, is based upon a number of assumptions that are inherently uncertain and is subject to numerous business, political, economic, competitive, financial and regulatory risks, including the risks described in this "*Risk Factors*" section and under "*Cautionary Statement Regarding Forward-Looking Statements.*" Many of these risks and uncertainties are beyond our control, such as declines in commodity prices and the speculative nature of estimating natural gas and NGL reserves and in projecting future rates of production. If any of these risks and uncertainties actually occur or the assumptions underlying our guidance are incorrect, our actual operating results, costs and activities may be materially and adversely different from our guidance. In addition, investors should also recognize that the reliability of any guidance diminishes the farther in the future that the data is forecast. In light of the foregoing, investors are urged to put our guidance in context and not to place undue reliance upon it.

We may not have sufficient available cash to pay any dividends on our common stock.

Holders of our common stock do not have a right to dividends on such shares unless declared or set aside for payment by our board of directors. Under Delaware law, cash dividends on capital stock may only be paid from "surplus" or, if there is no "surplus," from the corporation's net profits for the then-current or the preceding fiscal year. Unless we operate profitably, our ability to pay dividends on our common stock would require the availability of adequate "surplus," which is defined as the excess, if any, of net assets (total assets less total liabilities) over capital.

We may not have sufficient available cash to enable us to pay any dividends to our stockholders. The actual amount of available cash we will have to pay dividends will be reduced by the cost to fund acquisitions without issuing additional equity or debt, payments in respect of our debt instruments, other contractual obligations, operating expenses, general and administrative expenses, maintenance capital expenditures and reserves for future capital needs that our board of directors may determine are appropriate.

The payment of regular dividends on our common stock is subject to the discretion of our board of directors.

Our stockholders will have no contractual or other legal right to dividends. The payment of future dividends on our common stock will be at the discretion of our board of directors and any determination to pay dividends and the amount of any such dividends will depend on general economic and business conditions, our financial condition, capital requirements, results of operations, contractual limitations, legal, tax, regulatory and contractual restrictions and implications on the payment of dividends by us to our stockholders or by our subsidiaries to us, including the restrictions under our current and any future debt agreements, potential acquisition opportunities and the availability and desirability of financing alternatives, the need to service our indebtedness or other current and anticipated cash needs and any other factors our board of directors deem relevant. Events may occur, including a reduction in anticipated production volumes or realized prices or other events, which could materially impact the actual amount of any dividends we pay. Our board of directors will have the authority to establish cash reserves for the prudent conduct of our business, and the establishment of or increase in those reserves could result in a reduction in cash available for distribution to pay dividends on our common stock at anticipated levels. Accordingly, we may not be able to make, or may have to reduce or eliminate, the payment of dividends on our common stock, which could adversely affect the market price of our common stock. Investors are cautioned not to place undue reliance on the permanence of a dividend policy in making an investment decision.

The agreements governing our indebtedness impose restrictions on dividend payments.

The Term Loan Credit Agreement and the Revolving Credit Agreement contain, and any future debt agreement may contain, covenants that prohibit us from paying dividends on our common stock under certain circumstances. Both the Term Loan Credit Agreement and the Revolving Credit Agreement permit us to pay quarterly dividends to our stockholders if, among other things, (1) we have earned sufficient free cash flow (as defined in the Term Loan Credit Agreement), (2) our pro forma available cash is greater than $100.0 million and (3) our adjusted stockholders' equity (as defined generally to mean our stockholders' equity as determined in accordance with GAAP determined in the most recently delivered financial statements, adjusted to exclude certain unrealized earnout obligations and unrealized gains or losses resulting from hedging agreements and the application of the applicable accounting standard for the hedging instruments) is not less than $800.0 million. There can be no assurance that we will generate sufficient cash flow to permit us to pay dividends in compliance with the Term Loan Credit Agreement, the Revolving Credit Agreement or any other debt agreement.

Restrictions on distributions to us by our subsidiaries and affiliates under agreements governing their future indebtedness could limit our ability to pay dividends to holders of our common stock. These agreements contain financial tests and covenants that our subsidiaries and affiliates must satisfy prior to making distributions. If any of our subsidiaries or affiliates is unable to satisfy these restrictions or is otherwise in default under such agreements, it would be prohibited from making distributions to us that could, in turn, limit our ability to pay dividends to holders of our common stock.

The amount of our quarterly cash dividends, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business.

Investors who are looking for an investment that will pay regular and predictable quarterly dividends should not invest in our common stock. Our future business performance may be volatile and our cash flows may be unstable and we do not intend to maintain excess dividend coverage for the purpose of maintaining stability or growth in our dividends nor do we intend to reserve cash for dividends in future periods or incur debt to pay dividends. Because our dividends will be dependent upon the amount of cash we generate each quarter after payment of our fixed and variable expenses and after reserves for (i) debt service and other contractual obligations and fixed charges and (ii) future operating and capital needs, any future quarterly dividends paid to our stockholders will vary significantly from quarter to quarter, and may be zero, and our stockholders have no contractual or other legal right to dividends. See "*Dividend Policy*."

Our board of directors will initially adopt a policy to pay dividends to our stockholders, which could limit our ability to grow and make acquisitions.

As a result of our dividend policy, we will have limited cash available to fund acquisitions, and we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions. As such, to the extent we are unable to finance growth externally, our dividend policy may significantly impair our ability to grow.

To the extent we issue additional shares of common stock in connection with any acquisitions or as in-kind dividends, the payment of dividends on those additional shares of common stock may increase the risk that we will be unable to maintain or increase our per share dividend level. The incurrence of commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, would reduce the available cash that we have to distribute to our stockholders.

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

Upon becoming a public company, we will be required to comply with new laws, regulations and requirements, certain corporate governance provisions of Sarbanes-Oxley Act, related regulations of the SEC and the requirements of the NYSE, with which we were not required to comply as a private company.

Complying with these statutes, regulations and requirements will occupy a significant amount of our time and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function to test and conclude on the sufficiency of our internal control over financial reporting;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside professionals in the above activities.

Furthermore, while we generally must comply with Section 404 of the Sarbanes-Oxley Act, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal control over financial reporting until our first annual report subsequent to our ceasing to be an "emerging growth company." At any time, we may conclude that our internal controls, once tested, are not operating as designed or that the system of internal controls does not address all relevant financial statement risks. Once required to attest to the effectiveness of our internal control over financial reporting, our independent registered public accounting firm may issue a report that concludes it does not believe our internal control over financial reporting is effective. Compliance with Sarbanes-Oxley Act requirements may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we will be subject to significant regulatory oversight and reporting obligations under U.S. federal securities laws and the continuous scrutiny of securities analysts and investors. In addition, most members of our management team have limited experience managing a public company, interacting with public company investors, and complying with the increasingly complex laws pertaining to public companies. Our management team may not successfully or efficiently manage us as a public company. These new obligations and constituents require significant attention from our management team and could divert our management team's attention away from the day-to-day management of our business, which could adversely affect our business, results of operations and financial condition.

Further, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

We have identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future, or otherwise fail to maintain effective internal controls over financial reporting, which could result in a restatement of our financial statements or cause us to fail to meet our reporting obligations.

We identified certain material weaknesses in our internal control over financial reporting during the second quarter of 2022. As of December 31, 2022, those material weaknesses remained un-remediated. A "material weakness" is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

We did not design and maintain effective controls to communicate relevant information among departments to completely and accurately record and disclose transactions in the financial statements. This material weakness contributed to two additional material weaknesses in our internal controls. We did not design and maintain effective controls related to (i) the accounting for stock awards and common stock with certain put rights, including the value and classification of such arrangements, and (ii) the communication and evaluation of terms and conditions set forth in complex contracts, including certain of our commodity derivative contracts, relevant to our compliance with financial covenants and related disclosures.

Finally, we did not design and maintain effective controls related to the accounting for income taxes, which were not designed at a sufficient level of precision or rigor to prepare and review the tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and disclosures in the consolidated financial statements, which also resulted in a material weakness in our internal control over financial reporting.

The material weaknesses described above resulted in audit adjustments to share capital and other mezzanine equity accounts, liquidity disclosures, income tax benefit, income taxes payable to related party and deferred tax assets. Additionally, each of the material weaknesses described above could result in a misstatement of the aforementioned account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

We have begun to take steps towards remediating these material weaknesses primarily by designing and implementing additional internal controls, including those related to (i) the communication of relevant information across departments, (ii) the valuation and classification of stock awards and common stock with certain put rights, (iii) the communication and evaluation of terms and conditions included in complex contracts relevant to our compliance with financial covenants and related disclosures, and (iv) the preparation and review of the income tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and income tax disclosures. Although we believe we are addressing the internal control deficiencies that led to the material weaknesses, the measures we have taken, and plan to take, may not be effective.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. 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 control over financial reporting in the future, or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act.

We cannot assure you that we have identified all, or that we will not in the future have additional, material weaknesses. Material weaknesses may still exist when we report on the effectiveness of our internal control over financial reporting as required by reporting requirements under Section 404 of the Sarbanes-Oxley Act after the completion of this offering. If material weaknesses emerge related to financial reporting, we encounter difficulties in implementing or improving our internal controls or we otherwise fail to develop and maintain effective internal control over financial reporting, our reputation and operating results could be harmed, we could fail to meet our reporting obligations, or we may have a restatement of our financial statements. Ineffective internal control over financial reporting could also cause current and potential investors to lose confidence in our reported financial information, which would harm our business and likely have a negative effect on the trading price of our shares of common stock.

There is no existing market for our common stock, and we do not know if one will develop.

Prior to this offering, there has not been a public market for our common stock. We cannot predict the extent to which investor interest in the Company will lead to the development of an active trading market on the stock exchange on which we list our common stock or otherwise or how liquid that market might become. If an active trading market does not develop, anyone purchasing our common stock may have difficulty selling it. The initial public offering price for the common stock was determined by negotiations between us and the representatives of the underwriters and may not be indicative of prices that will prevail in the open market following this offering. Consequently, purchasers of our common stock may be unable to sell it at prices equal to or greater than the price paid.

The following factors could affect our stock price:

- quarterly variations in our financial and operating results;
- public reaction to our press releases, our other public announcements and our filings with the SEC;
- strategic actions by our competitors;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our common stock;
- sales of our common stock by us or our stockholders, or the perception that such sales may occur;
- changes in accounting principles, policies, guidance interpretations or standards;
- additions or departures of key management personnel;
- actions by our stockholders;
- general market conditions, including, among other things, fluctuations in commodity prices;
- domestic and international political, economic, legal and regulatory factors unrelated to our performance; and

- the realization of any risks described in this “*Risk Factors*” section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company’s securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management’s attention and resources and harm our business, operating results and financial condition.

Our governing documents, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock. The existence of significant stockholders, such as Banpu, may have similar effects.

Some provisions of our governing documents could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- providing for a classified board of directors;
- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;
- the requirement that the affirmative vote of the holders of at least 66⅔% in voting power of all the then-outstanding shares of our stock be obtained to amend and restate our existing bylaws or to remove directors;
- the requirement that the affirmative vote of the holders of at least 66⅔% in voting power of all the then-outstanding shares of our stock (or, if approved by at least 60% of our board of directors, a majority in voting power of all the then-outstanding shares of our stock) be obtained to amend our certificate of incorporation; and
- providing that the board of directors is expressly authorized to make, repeal, alter, amend and rescind our bylaws.

In addition, the existence of significant stockholders, such as Banpu, may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of the Company. Moreover, Banpu’s concentration of stock ownership in us may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

Investors in this offering will experience immediate and substantial dilution of $ per share.

Based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover of this prospectus), purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the as adjusted net tangible book value per share of common stock from the initial public offering price. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated proceeds (after deducting estimated underwriting discounts and commissions and estimated offering expenses), our as adjusted net tangible book value as of December 31, 2022 would have been approximately $ per share. This dilution is due in large part to earlier investors having paid substantially less than the initial public offering price when they purchased their shares. “*Dilution*” contains additional information.

Future sales of our common stock in the public market, or the perception that such sales may occur, could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may issue additional shares of common stock or convertible securities in subsequent public offerings. After the completion of this offering, assuming the underwriters’ option to purchase additional shares is fully exercised, we will have outstanding shares of common stock. This number includes shares of common stock that we are selling in this offering and shares of common stock that we may sell in this offering if the underwriters' option to purchase additional shares is fully exercised, which may be resold immediately in the public market. Immediately following the completion of this offering, Banpu will own shares of common stock, representing approximately % of our total outstanding common stock (or % if the underwriters' option to purchase additional shares is exercised in full) and management, directors and other employee and non-employee stockholders, collectively, will own shares of common stock, representing approximately % of our total outstanding common stock (or % if the underwriters' option to purchase additional shares is exercised in full). All such shares are restricted from immediate resale under the federal securities laws and all such shares are subject to the lock-up agreements between such parties and the underwriters described in "*Underwriting*" but may be sold into the market in the future.

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets at any time following the date that is six months after the consummation of this offering. "*Shares Eligible for Future Sale*" and "*Certain Relationships and Related Party Transactions — Registration Rights*" contain additional information regarding such rights.

In addition, in connection with this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of shares of our common stock issuable or reserved for issuance under our equity incentive plans. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under the registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition or shares owned by Banpu and such other stockholders), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Our common stock will not be entitled to preemptive rights to buy shares from us. As a result, stockholders will not have the automatic ability to avoid dilution in their percentage ownership of us.

Terms of subsequent financings may adversely impact stockholder equity.

If we raise more equity capital from the sale of common stock, institutional or other investors may negotiate terms more favorable than the current prices of our common stock. If we issue debt securities, the holders of the debt would have a claim to our assets that would be prior to the rights of stockholders until the debt is paid. Interest on these debt securities would increase costs and could negatively impact our operating results.

In accordance with Delaware law and the provisions of our certificate of incorporation, we may issue one or more classes or series of preferred stock that ranks senior in right of dividends, liquidation or voting to our common stock. Preferred stock may have such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine, and the issuance of preferred stock would dilute the ownership of our existing stockholders. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock. The terms of any series of preferred stock may also reduce or eliminate the amount of cash available for payment of dividends to our holders of common stock or subordinate the claims of our holders of common stock to our assets in the event of our liquidation. Our common stock will not be subject to conversion, redemption or sinking fund provisions.

The representatives of the underwriters of this offering may waive or release parties to the lock-up agreements entered into in connection with this offering, which could adversely affect the price of our common stock.

We, Banpu and all of our directors and executive officers have entered into lock-up agreements with respect to their ownership of our common stock, pursuant to which we and they are subject to certain resale restrictions for a period of 180 days following the effectiveness date of the registration statement of which this prospectus forms a part. The representatives of the underwriters, at any time and without notice, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If the restrictions under the lock-up agreements are waived, then common stock will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital. "*Underwriting*" provides additional information regarding the lock-up agreements.

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

The trading market for our common stock 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 the Company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover the Company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

Our certificate of incorporation will designate the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our certificate of incorporation will provide that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by law, be the sole and exclusive forum for any (i) derivative action or proceeding brought on behalf of the Company, (ii) action asserting a claim of breach of a fiduciary duty owed by any director, officer or employee of the Company to the Company or our stockholders, (iii) action asserting a claim against the Company or any director or officer of the Company arising pursuant to any provision of the Delaware General Corporation Law (the "DGCL") or our governing documents, or (iv) action asserting a claim against the Company or any director, officer or employee of the Company, which claim is governed by the internal affairs doctrine. Notwithstanding the foregoing sentence, the federal district courts of the United States of America shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under U.S. federal securities laws, including the Securities Act and the Exchange Act. This choice of forum may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our governing documents 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 financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenue and losses, projected costs, prospects, plans and objectives of management and dividend policy are forward-looking statements. When used in this prospectus, words such as “expect,” “project,” “estimate,” “believe,” “anticipate,” “intend,” “budget,” “plan,” “seek,” “envision,” “forecast,” “target,” “predict,” “may,” “should,” “would,” “could,” “will,” the negative of these term and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under “*Risk Factors*.” 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.

Forward-looking statements may include statements about, among other things:

- our business strategy;
- our reserves;
- our financial strategy, liquidity and capital required for our development programs;
- our relationship with Banpu, including future agreements with Banpu;
- estimated natural gas, NGL and oil prices;
- our dividend policy;
- the timing and amount of future production of natural gas, NGL and oil;
- our hedging strategy and results;
- our drilling plans;
- competition and government regulation;
- legal, regulatory or environmental matters;
- marketing of natural gas, NGL and oil;
- business or leasehold acquisitions and integration of acquired businesses;
- our ability to develop existing prospects;
- costs of developing our properties and of conducting our operations;
- our plans to establish midstream contracts that allow us to supply our own natural gas directly to Temple I;
- our plan to continue to build out our power generation business and to expand into retail power;
- our ability to produce and sell MNZ gas;
- our ability to effectively operate and grow our CCUS business;
- our ability to reach FID and execute and complete any of our pipeline of identified CCUS projects;
- our ability to identify and complete additional CCUS projects as we expand our upstream operations;
- our anticipated Scope 1, Scope 2 and Scope 3 emissions from our owned and operated upstream businesses and our plans to offset our Scope 1, Scope 2 and Scope 3 emissions from our owned and operated upstream business;
- the impact of the COVID-19 pandemic and its effects on our business and financial condition;
- general economic conditions;

- cost inflation;
- credit markets;
- our ability to service our indebtedness;
- our ability to expand our business, including through the recruitment and retention of skilled personnel;
- our future operating results;
- the remediation of our material weaknesses; and
- our plans, objectives, expectations and intentions.

The forward-looking statements included in this prospectus are based on current expectations and involve numerous risks and uncertainties, most of which are difficult or impossible to predict and many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas, NGLs and oil. Assumptions relating to these forward-looking statements involve judgments, risks and uncertainties with respect to, among other things, market factors (including competition and inflation), market prices (including geographic basis differentials) of natural gas, NGLs and oil, results of future drilling and marketing activity, future production and costs (including availability of drilling and production equipment and services), legislative and regulatory initiatives, electronic, cyber or physical security breaches, drilling and other operating risks, environmental risks (including weather-related events), future business decisions, the uncertainty inherent in estimating natural gas, NGL and oil reserves and the other risks described under "*Risk Factors.*"

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil 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 reserve 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, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered.

Although we believe that the assumptions underlying these forward-looking statements are reasonable, should one or more of the risks or uncertainties described in this prospectus occur, or should underlying assumptions prove incorrect, actual outcomes and our results and financial condition may differ materially from those indicated in any forward-looking statements. In light of the significant uncertainties inherent in these forward-looking statements, the inclusion of such information should not be regarded as a representation by us or any other person that our objectives and plans will be achieved.

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.

All forward-looking statements, expressed or implied, in this prospectus are based only on information currently available to us and speak only as of the date on which they are made. Except as otherwise required by applicable law, we disclaim any duty to publicly update any forward-looking statement, each of which is expressly qualified by the statements in this section, to reflect events or circumstances after the date of this prospectus.

USE OF PROCEEDS

We estimate that the net proceeds to us from the sale of our common stock in this offering, after deducting underwriting discounts and commissions and estimated offering expenses payable by us, will be approximately $ million (or approximately $ million if the underwriters exercise in full their option to purchase additional shares), based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus).

Each $1.00 increase (decrease) in the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) would increase (decrease) the net proceeds to us from this offering by $ million, assuming that the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We may also increase or decrease the number of shares we are offering. Each increase (decrease) of 1.0 million shares in the number of shares we are offering would increase (decrease) the net proceeds to us from this offering by $ million, assuming that the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) remains the same, and after deducting underwriting discounts and commissions and estimated offering expenses payable by us.

Of the net proceeds we receive from the sale of our common stock in this offering, we intend to use approximately $ million to repay in full the loan under the $75 Million A&R Loan Agreement with BNAC, $ million to make additional contingent consideration payments payable in connection with the Devon Barnett Acquisition and the remainder for other general corporate purposes, including to fund the expansion of our CCUS business.

On March 10, 2022, we borrowed $75.0 million under the $75 Million Loan Agreement with BNAC to fund the deposit for the Exxon Barnett Acquisition. On June 15, 2022, we entered into the $75 Million A&R Loan Agreement, which amended and restated the $75 Million Loan Agreement to, among other things, subordinate the $75.0 million term loan owed to BNAC thereunder to the term loans we borrowed under the Term Loan Credit Agreement. Interest on the outstanding principal is SOFR plus 5.25% and is payable on a semi-annual basis. The principal balance of $75.0 million is due on December 31, 2027, including any unpaid interest. For additional information, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Subordinated Intercompany Loan Agreements.*"

For additional information on the contingent consideration payments described above, see "*Note 16 — Commitments and Contingencies*" to our audited consolidated financial statements included elsewhere in this prospectus.

DIVIDEND POLICY

We currently do not pay a fixed cash dividend to holders of our common stock. Although we will not be required by any law, our certificate of incorporation or our bylaws to pay dividends, at or prior to the closing of this offering, our board of directors will adopt a written policy pursuant to which we intend to pay to stockholders, subject to the factors described below, including the restrictions under the Term Loan Credit Agreement and the Revolving Credit Agreement, quarterly cash dividends and to consider the payment of additional special dividends from time to time.

All dividends will be subject to the sole discretion of our board of directors and the considerations discussed below. We intend to pay dividends out of cash flows from operations to the extent available, and our stockholders have no contractual or other legal right to dividends.

Any determination to declare and pay a regular or special dividend, as well as the amount of any such dividends, will depend on our board of directors' consideration of general economic and business conditions, our financial condition and results of operations, capital requirements, restrictions under our indebtedness, potential acquisition opportunities and other current and anticipated cash needs and any other factors our board of directors deems relevant. Events may occur, including a reduction in anticipated production volumes or realized prices or other events, which could materially impact the actual amount of any dividends we pay. In addition, our board of directors may be required to, or may elect to, reduce, or eliminate our dividends during periods of reduced prices or demand for oil and natural gas, among other reasons.

Our dividend policy may change from time to time, and there can be no assurance that we will declare any regular or special cash dividends at all or in any particular amounts.

Each of the Term Loan Credit Agreement and the Revolving Credit Agreement permits us to pay quarterly dividends to our stockholders if, among other things, (1) we have earned sufficient free cash flow (as defined in the Term Loan Credit Agreement and the Revolving Credit Agreement), (2) our pro forma available cash is greater than $100.0 million and (3) our adjusted stockholders' equity (as defined generally to mean our stockholders' equity as determined in accordance with GAAP as determined in the most recently delivered financial statements, adjusted to exclude certain unrealized earnout obligations and unrealized gains or losses resulting from hedging agreements and the application of the applicable accounting standard for the hedging instruments) is not less than $800.0 million.

CAPITALIZATION

The following table shows our capitalization as of December 31, 2022:

- on an actual basis; and
- on an as adjusted basis, after giving effect to the sale of shares of our common stock in this offering (which assumes that the underwriters do not exercise their option to purchase additional shares), at an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), our receipt of the estimated net proceeds of this offering and after deducting underwriting discounts and commissions and estimated offering expenses payable by us and the application of such net proceeds as described under "*Use of Proceeds*."

The as adjusted information set forth in the table below is illustrative only and will adjust based on the actual initial public offering price and other terms of this offering determined when the initial public offering price is determined. You should read the following table together with "*Prospectus Summary — Summary Historical and Unaudited Pro Forma Financial Information*," "*Management's Discussion and Analysis of Financial Condition and Results of Operations*," "*Prospectus Summary — Summary Reserve, Production and Operating Data*," and our historical consolidated financial statements and the related notes thereto included elsewhere in this prospectus.

	As of December 31, 2022	
	Actual	**As Adjusted**
	(in thousands)	
Cash and cash equivalents, including restricted cash	$ 153,128	$
Debt:		
Notes payable to related party[1]	$ 75,000	$
Term Loan Credit Agreement	564,037	
Credit facilities	90,000	
Total debt[2]	$ 729,037	$
Mezzanine equity[3]:		
Common stock-minority ownership puttable shares	$ 62,712	$
Equity-based compensation	89,171	
Total mezzanine equity	$ 151,883	$
Stockholders' equity:		
Common stock, par value $.01 per share; 300,000,000 authorized shares; 117,325,797 shares issued and outstanding, actual; and shares issued and outstanding, as adjusted[4]	$ 1,132	$
Treasury stock, shares at cost; 386,000 shares	(3,974)	
Additional paid-in capital	896,433	
Accumulated deficit	(150,450)	
Total stockholders' equity	$1,044,041	$
Total capitalization	$2,078,089	$

(1) Represents the term loans under the $75 Million Loan Agreement with BNAC. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities*."

(2) As of April 13, 2023, we had total outstanding debt of $695.0 million, which consisted of (i) $75.0 million in aggregate principal amount under the $75 Million A&R Loan Agreement with BNAC, a wholly owned subsidiary of our parent, Banpu, which is subordinated to our obligations under the Term Loan Credit Agreement, (ii) $570.0 million in aggregate principal amount under the Term Loan Credit

Agreement, (iii) $15.0 million in aggregate principal amount under our SCB Credit Facility and (iv) $35.0 million in aggregate principal amount under our OCBC Credit Facility.

(3) Holders of certain minority ownership shares of our common stock, shares of our common stock issued as stock compensation and shares of common stock purchased through our employee stock purchase program have the right, at their respective option, to require the Company to repurchase the shares upon the occurrence of certain events. As a result, the fair value of these common shares is recognized within mezzanine equity in our consolidated balance sheets. In connection with the closing of this offering, the put rights with respect to these shares will be terminated and the related shares of common stock will be reclassified as permanent equity.

(4) The number of shares of our common stock issued and outstanding on an as adjusted basis assumes that the underwriters will not exercise their option to purchase additional shares. If the underwriters exercise in full their option to purchase additional shares, as adjusted cash and cash equivalents, additional paid-in capital, total stockholders' equity, total capitalization and shares of common stock outstanding as of December 31, 2022 would have been $, $, $, $, and $, respectively.

The number of shares of our common stock set forth in the table above excludes an aggregate of 10,000,000 additional shares of our common stock reserved for future awards pursuant to the 2022 Plan, including shares of common stock that may be issued upon vesting of equity awards that we expect to be granted in connection with this offering, and 1,000,000 shares of our common stock available for purchase by employees pursuant to the ESPP.

DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Our net tangible book value as of December 31, 2022 was $ million, or $ per share. Net tangible book value per share is determined by dividing our tangible net worth (tangible assets less total liabilities) by the total number of shares of common stock that were outstanding as of December 31, 2022. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds (after deducting estimated underwriting discounts and commissions and estimated offering expenses), our as adjusted net tangible book value as of December 31, 2022 would have been approximately $ million, or $ per share. This represents an immediate increase in the net tangible book value of $ per share to our existing stockholders and an immediate dilution (*i.e.*, the difference between the initial public offering price per share of our common stock and the as adjusted net tangible book value per share of our common stock after this offering) to new investors purchasing shares of common stock in this offering of $ per share.

The following table illustrates the per share dilution to new investors purchasing shares of common stock in this offering:

Assumed initial public offering price per share		$
Net tangible book value per share as of December 31, 2022	$	
Increase in net tangible book value per share attributable to new investors in this offering		
Less: As adjusted net tangible book value per share of common stock after giving effect to this offering		
Dilution in as adjusted net tangible book value per share to new investors from this offering		$

A $1.00 increase (decrease) in the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), would increase (decrease) the as adjusted net tangible book value per share after this offering by $ per share and increase (decrease) the dilution in net tangible book value per share to new investors in this offering by $ per share, in each case assuming the number of shares of common stock offered by us, as set forth on the cover page of this prospectus, remains the same and less estimated underwriting discounts and commissions and estimated offering expenses payable by us (and if the underwriters exercise in full their option to purchase additional shares, the as adjusted net tangible book value per share would be $ per share, and the dilution in net tangible book value per share to new investors in this offering would be $ per share).

The following table summarizes, as of December 31, 2022, the differences between the number of shares issued as a result of this offering, the total amount paid by existing shareholders and the average price per share to be paid by investors in this offering, based upon an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus).

	SHARES		TOTAL CONSIDERATION		AVERAGE PRICE PER SHARE
	NUMBER	PERCENT	AMOUNT	PERCENT	
Existing stockholders					
Existing common stock stockholders		%		%	$
Existing mezzanine equity stockholders[1]		%		%	$
Total existing stockholders		%		%	$
New investors		%		%	
Total		100%	$	100%	$

(1) Holders of certain minority ownership shares of our common stock have the right, at their option, to require us to repurchase the shares upon the occurrence of certain events. As a result, the fair value of these common shares is recognized within mezzanine equity in our consolidated balance sheets. In connection with the closing of this offering, the put rights with respect to these shares will be terminated and the related shares of common stock will be reclassified as permanent equity.

The above tables and related discussion are based on the number of shares of our common stock to be outstanding as of the closing of this offering. If the underwriters' option to purchase additional shares is exercised in full, the number of shares held by new investors will be increased to , or approximately % of the total number of shares of common stock. The above tables and related discussion exclude an aggregate 10,000,000 of additional shares of our common stock reserved for future awards pursuant to the 2022 Plan and 1,000,000 additional shares reserved to be available for purchase by employees pursuant to the ESPP.

UNAUDITED PRO FORMA COMBINED CONSOLIDATED FINANCIAL STATEMENTS

On June 30, 2022, the Company closed the Exxon Barnett Acquisition pursuant to which it acquired certain natural gas upstream assets and associated midstream infrastructure in the Barnett (the “2022 Barnett Assets”) from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation, for an adjusted cash purchase price of $619.4 million, plus additional contingent consideration of up to $50.0 million depending on future natural gas prices. In connection with the Exxon Barnett Acquisition, the Company entered into a Term Loan Credit Agreement with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent. On June 30, 2022, the Company borrowed $570.0 million of term loans under the Term Loan Credit Agreement to fund a portion of the purchase price and other costs and expenses associated with the Exxon Barnett Acquisition. Additionally, in March 2022, the Company borrowed $75.0 million under a Loan Agreement (the “$75 Million Loan Agreement”) with Banpu North America Corporation (“BNAC”), which owns 95.9% of the Company’s shares of common stock, to fund the deposit for the Exxon Barnett Acquisition.

The following unaudited pro forma combined consolidated financial statements (the “pro forma financial statements”) present the combination of the historical consolidated financial statements of the Company, as adjusted to give effect to the Exxon Barnett Acquisition, the related financing under the Term Loan Credit Agreement and the $75 Million Loan Agreement (collectively the “Transaction”). The Exxon Barnett Acquisition was consummated on June 30, 2022 and, therefore, (i) the 2022 Barnett Assets and related financing are included in the historical balance sheet of the Company as of December 31, 2022, together with the related indebtedness under the Term Loan Credit Agreement and the $75 Million Loan Agreement, and no pro forma balance sheet is presented and (ii) pro forma standardized measure of discounted future net cash flows are not presented due to the reserves associated with the 2022 Barnett Assets being included in the Company’s historical consolidated financial statements as of December 31, 2022. The unaudited pro forma combined consolidated statements of operations (the “pro forma statements of operations”) present the historical consolidated statement of operations of the Company for the year ended December 31, 2022, after giving effect to the Transaction as if it had been consummated on January 1, 2022. As the Exxon Barnett Acquisition was consummated on June 30, 2022, the Company’s historical consolidated statement of operations for the year ended December 31, 2022 includes six months of revenues and expenses attributable to the 2022 Barnett Assets.

The pro forma financial statements were prepared in accordance with Article 11 of Regulation S-X under the Securities Act. The unaudited pro forma adjustments reflecting the Exxon Barnett Acquisition have been prepared in accordance with the acquisition method of accounting in accordance with FASB ASC Topic 805, *Business Combinations*, which requires all assets acquired and liabilities assumed to be recorded at fair value at the acquisition date. The purchase price adjustments recorded on June 30, 2022 are preliminary and are subject to change as additional information becomes available and as additional analysis is performed. For more information on the fair value of assets acquired and liabilities assumed, see our audited consolidated financial statements included elsewhere in this prospectus. Upon consummation of the Transaction, management did not identify any differences in accounting policies that would have a material impact on the pro forma financial statements.

Certain of the historical amounts with respect to the 2022 Barnett Assets have been reclassified to conform to the Company’s financial statement presentation.

Assumptions and estimates underlying the pro forma adjustments are described in the accompanying notes, which should be read in conjunction with the pro forma financial statements. In the Company’s opinion, all adjustments that are necessary to present fairly the pro forma information have been made.

The pro forma financial statements are provided for illustrative purposes only and are not intended to represent what the Company’s financial position or results of operations would have been had the Transaction occurred on the assumed date nor do they purport to project the future operating results or the financial position of the Company following the Transaction. The pro forma financial statements do not reflect projected synergies or future events that may occur after the Transaction, including, but not limited to, the anticipated realization of savings from potential operating efficiencies, asset dispositions, cost savings, or economies of scale that the Company may achieve as a result of the Transaction or the costs that may be necessary to incur in order to achieve such synergies or savings.

The pro forma adjustments reflecting the consummation of the Transaction are based on certain currently available information and certain assumptions and methodologies that the Company believes are reasonable under the circumstances. The pro forma adjustments, which are described in the accompanying notes, may be revised as additional information becomes available and is evaluated. Therefore, it is likely that the actual results will differ from the pro forma adjustments and it is possible the difference may be material. The Company believes that its assumptions and methodologies provide a reasonable basis for presenting all of the significant effects of the Transaction based on information available to management at this time and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma combined consolidated financial information.

Additionally, the Company cannot assure that it will not incur charges in excess of those included in the pro forma total consideration related to the Transaction or that the Company's efforts to integrate the operations of the 2022 Barnett Assets will be successful.

The pro forma financial statements should be read in conjunction with "*Management's Discussion and Analysis of Financial Condition and Results of Operations*," as well as the Company's historical consolidated financial statements and related notes, the historical statements of revenues and direct operating expenses and related notes for the 2022 Barnett Assets acquired in the Exxon Barnett Acquisition and other financial information included elsewhere in this prospectus. Historical and pro forma results are not necessarily indicative of results that may be expected for any future period.

	For the Year Ended December 31, 2022 BKV Corporation Historical	For the Six Months Ended June 30, 2022 2022 Barnett Assets Historical	Transaction Accounting Adjustments[1]		Financing Adjustments		Pro Forma Combined	
Revenues and other operating income / Revenues								
Natural gas, NGL, and oil sales	$ 1,633,747	$ —	$ 219,232	(aa)	$ —		$1,852,979	
Midstream revenues	12,676	—	3,621	(aa)	—		16,297	
Derivative losses, net	(629,701)	—	—		—		(629,701)	
Marketing revenues	11,001	—	—		—		11,001	
Other	2,799	—	248	(aa)	—		3,047	
Oil and condensate, gas and NGL sales	—	219,232	(219,232)	(aa)	—		—	
Midstream operating revenues	—	3,621	(3,621)	(aa)	—		—	
Other revenues	—	248	(248)	(aa)	—		—	
Total revenues and other operating income / Total revenues	**1,030,522**	**223,101**	**—**		**—**		**1,253,623**	
Operating expenses / Direct operating expenses								
Lease operating and workover	135,064	—	58,176	(aa)	—		193,240	
Taxes other than income	114,668	—	10,696	(aa)	—		125,364	
Gathering and transportation	208,758	—	25,321	(aa)	—		234,079	
Depreciation, depletion, amortization, and accretion	118,909	—	26,191	(bb)	—		145,100	
General and administrative	148,559	—	—		—		148,559	
Lease operating expense	—	47,456	(47,456)	(aa)	—		—	
Overhead costs	—	10,720	(10,720)	(aa)	—		—	
Cost of goods sold	—	25,321	(25,321)	(aa)	—		—	
Production and property taxes	—	10,696	(10,696)	(aa)	—		—	
Total operating expenses / Total direct operating expenses	**725,958**	**94,193**	**26,191**		**—**		**846,342**	
Income from operations / Revenues in excess of direct operating expenses	**304,564**	**128,908**	**(26,191)**		**—**		**407,281**	
Other income and expense								
Bargain purchase gain	170,853	—	—		—		170,853	
Gain on settlement of litigation	16,866	—	—		—		16,866	
Gain on contingent consideration liabilities	6,632	—	—		—		6,632	
Earnings from equity affiliate	8,493	—	—		—		8,493	
Interest income	1,143	—	—		—		1,143	
Interest expense	(26,322)	—	—		(21,074)	(cc)	(47,396)	
Interest expense, related party	(10,846)	—	—		(817)	(dd)	(11,663)	
Other income	1,411	—	—		—		1,411	
Income from continuing operations before income taxes	**472,794**	**128,908**	**(26,191)**		**(21,891)**		**553,620**	
Income tax expense	(62,652)	—	(23,625)	(ee)	5,035	(ff)	(81,242)	
Net income	**$ 410,142**	**$ 128,908**	**$ (49,816)**		**$ (16,856)**		**$ 472,378**	
Net income per common share:								
Basic	$ 3.50						$ 4.03	(gg)
Diluted	$ 3.31						$ 3.81	(gg)
Weighted average number of common shares outstanding:								
Basic	117,318						117,318	
Diluted	123,980						123,980	

(1) Upon consummation of the Transaction, management did not identify any differences in accounting policies that would have a material impact on the unaudited pro forma combined.

NOTES TO UNAUDITED PRO FORMA COMBINED CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Basis of Presentation

The accompanying pro forma financial information was prepared based on the historical consolidated financial statements of the Company and the historical statements of revenues and direct operating expenses for the 2022 Barnett Assets acquired in the Exxon Barnett Acquisition. The pro forma financial statements were prepared in accordance with GAAP and Article 11 of Regulation S-X under the Securities Act. The Exxon Barnett Acquisition was consummated on June 30, 2022 and, therefore, (i) the 2022 Barnett Assets are included in the historical balance sheet of the Company as of December 31, 2022, together with the related indebtedness under the Term Loan Credit Agreement and the $75 Million Loan Agreement, and no pro forma balance sheet is presented, (ii) the Company's historical consolidated statement of operations for the year ended December 31, 2022 includes six months of revenues and expenses attributable to the 2022 Barnett Assets, and (iii) the reserves associated with the 2022 Barnett Assets are included in the Company's historical supplemental oil and gas reserve disclosures for the year ended December 31, 2022 and no supplemental pro forma oil and gas reserves information is presented.

The fair value of assets acquired and liabilities assumed and the fair value of contingent consideration as of June 30, 2022, the date the acquisition was completed, are as follows (in thousands):

Cash	$ 619,437
Contingent consideration	17,150
Total consideration	$ 636,587
Assets acquired and liabilities assumed:	
Inventory	150
Natural gas properties-developed	657,935
Midstream assets	260,844
Other property and equipment	8,856
Property taxes	(6,296)
Deferred tax liability	(50,569)
Revenues payable	(16,612)
Asset retirement obligations	(46,867)
Total identifiable net assets	$ 807,441
Bargain purchase gain	$(170,853)

The pro forma statement of operations presents the historical consolidated statements of operations of the Company for the year ended December 31, 2022 after giving effect to the Transaction as if it had been consummated on January 1, 2022.

Note 2 — Adjustments to the Unaudited Pro Forma Combined Consolidated Statements of Operations

The pro forma adjustments reflected in the pro forma statement of operations are based on preliminary estimates and assumptions that are subject to change. The following adjustments have been reflected in the pro forma statement of operations:

(aa) Certain reclassification adjustments have been made to conform historical direct revenues and operating expenses with respect to the 2022 Barnett Assets to the financial statement presentation method of the Company.

- Reclassification of 2022 Barnett Assets historical Oil and condensate, gas and NGL sales to Natural gas, NGL and oil sales to conform with the Company's presentation of upstream revenues.
- Reclassification of 2022 Barnett Assets historical Midstream operating revenues to Non-operated midstream revenues to conform with the Company's presentation of midstream revenues.

- Reclassification of 2022 Barnett Assets historical Other revenues to Other to conform with the Company's presentation of other revenues.
- Reclassification of 2022 Barnett Assets historical Lease operating expense to Lease operating and workover to conform with the Company's presentation of lease operating and workover expense.
- Reclassification of 2022 Barnett Assets historical Overhead costs to Lease operating and workover to conform with the Company's presentation of lease operating and workover expense.
- Reclassification of 2022 Barnett Assets historical Cost of goods sold to Gathering and transportation expense to conform with the Company's presentation of gathering and transportation expense.
- Reclassification of 2022 Barnett Assets historical Production and property taxes to Taxes other than income to conform with the Company's presentation of Taxes other than income.

Upon consummation of the Transaction, management did not identify any differences in accounting policies that would have a material impact on the pro forma statements of operations.

(bb) Reflects the pro forma depreciation, depletion, amortization and accretion expense based on the preliminary purchase price allocation. The historical financial statements for the 2022 Barnett Assets did not include historical depreciation, depletion, amortization and accretion due to the abbreviated presentation. As a result, this adjustment reflects the full go forward expense related to these items based on the fair value of the assets acquired as of June 30, 2022 and the relevant remaining useful life of those assets.

Depletion for natural gas properties is calculated using the units of production method of accounting for oil and gas properties. Pro forma depletion expense for the year ended December 31, 2022 was $20.5 million. As the Exxon Barnett Acquisition was consummated on June 30, 2022, the Company's historical consolidated statement of operations for year ended December 31, 2022 includes six months of depletion expense attributable to the 2022 Barnett Assets. Therefore, the pro forma depletion expense for the year ended December 31, 2022 represents depletion expense attributable to the 2022 Barnett Assets for the six months ended June 30, 2022. Pro forma depletion expense for the six months ended June 30, 2022 for the 2022 Barnett Assets was calculated based on production volumes attributable to the natural gas properties included in the 2022 Barnett Assets and depletion rate reflecting the reserve volumes acquired.

Depreciation and amortization expense for other property and equipment and midstream assets is calculated using the straight-line method. Pro forma depreciation and amortization expense for the year ended December 31, 2022 was $4.1 million. As the Exxon Barnett Acquisition was consummated on June 30, 2022, the Company's historical consolidated statement of operations for the year ended December 31, 2022 includes six months of depreciation and amortization expense attributable to the 2022 Barnett Assets. Therefore, the pro forma depreciation and amortization expense for the year ended December 31, 2022 represents depreciation and amortization expense attributable to the 2022 Barnett Assets for the six months ended June 30, 2022. The following table sets forth a listing of useful lives for the applicable other property and equipment:

	Useful Life
Pipelines	40 years
Compressors	25 years
Buildings	39 years
Furniture, fixtures, equipment, vehicles and other	5 years

Accretion expense is based on the preliminary purchase price allocation of the estimated fair value of the asset retirement obligations associated with the acquired proved natural gas properties and midstream assets included in the 2022 Barnett Assets. As the Exxon Barnett Acquisition was consummated on June 30, 2022, the Company's historical consolidated statement of operations for the year ended December 31, 2022 included six months of accretion expense attributable to the asset retirement obligations associated with the 2022 Barnett Assets. Therefore, the pro forma accretion expense for the year ended December 31, 2022 represents accretion expense attributable to the 2022 Barnett Assets for the six months ended June 30, 2022. The present value of the estimated asset retirement obligation associated with the acquired natural gas producing properties and midstream assets as of December 31, 2022 was $46.9 million, which was calculated using an interest rate of 8.01%, inflation rate of 2.50% and the expected remaining useful life of each well or associated midstream assets, estimated as a range of 5 – 50 years.

(cc) Reflects the impact of the interest expense, inclusive of debt issuance cost amortization, that would have been recognized as a result of the incurrence of $570.0 million in new debt under the Term Loan Credit Agreement used to fund a portion of the purchase price for the Exxon Barnett Acquisition and other costs and expenses associated with the acquisition.

The term loans mature five years after their initial incurrence and require the prepayment of 20% of their original principal amount on each anniversary of their initial incurrence. Loans under the Term Loan Credit Agreement bear interest at six-month term SOFR plus a credit spread adjustment of 0.10%, plus 4.75% per annum. The interest rate used for pro forma purposes is 7.43% based on the six-month term SOFR on June 22, 2022 (established prior to funding). Pursuant to the terms of the Term Loan Credit Agreement, the rate will be adjusted every six months. As a result, the actual interest rate could vary for the year ended December 31, 2022, and a one-eighth of a percent variance in the interest rate would cause a change in interest expense of approximately $0.3 million.

(dd) Reflects the impact of the interest expense that would have been recognized as a result of the incurrence of $75 million in new debt under the $75 Million Loan Agreement with BNAC used to fund the deposit on the Exxon Barnett Acquisition.

The $75 Million Loan Agreement matures five years after the initial incurrence and requires repayment of 20% of the original principal amount on each anniversary of the initial incurrence. The $75 Million Loan Agreement bears interest at six-month term SOFR plus 5.25% per annum. The interest rate used for pro forma purposes is 5.30%, based on the six-month term SOFR on March 10, 2022 (established prior to funding). The actual interest rate could vary for the year ended December 31, 2022, and a one-eighth of a percent variance in the interest rate would cause a change in interest expense by an immaterial amount.

(in thousands)	Year Ended December 31, 2022
Term Loan Credit Agreement	
Interest expense calculated for the period	$ 42,944
Less: Actual interest expense included in historical financial statements	(22,472)
Adjustment related to incremental interest expense[1]	$ 20,472
$75 Million Loan Agreement	
Interest expense calculated for the period	$ 4,030
Less: Actual interest expense included in historical financial statements	(3,213)
Adjustment related to incremental interest expense	$ 817

(1) Excludes debt issuance cost amortization for the year ended December 31, 2022 of $0.6 million. As the Exxon Barnett Acquisition was consummated on June 30, 2022, the Company's historical consolidated statement of operations for the year ended December 31, 2022 includes six months of debt issuance cost amortization attributable to the 2022 Barnett Assets. Therefore, the pro forma debt issuance cost amortization for the year ended December 31, 2022 represents debt issuance cost amortization attributable to the 2022 Barnett Assets for the six months ended June 30, 2022.

(ee) Reflects the adjustment for the income tax provision for transaction accounting adjustments related to the year ended December 31, 2022 of $23.6 million of income tax expense. Income tax impacts of transaction accounting adjustments include adjustments to record depreciation, depletion, amortization and accretion (see adjustment (bb) above), and reflects estimated incremental income tax provision associated with the pro forma results of operations assuming the 2022 Barnett Assets' earnings had been subject to federal and state income tax. The pro forma estimated blended statutory rate for the period presented is 23.0%. As the Exxon Barnett Acquisition was consummated on June 30, 2022, the Company’s historical consolidated statement of operations for the year ended December 31, 2022 includes six months of income tax expense attributable to the ongoing operations of the 2022 Barnett Assets. Therefore, the pro forma income tax expense for the year ended December 31, 2022 represents income tax expense attributable to the ongoing operations of the 2022 Barnett Assets for the six months ended June 30, 2022.

(ff) Reflects the adjustment for the income tax provision for financing adjustments related to the year ended December 31, 2022 of $5.0 million of income tax benefit. The pro forma estimated blended statutory rate used for the period presented is 23.0%. As the Exxon Barnett Acquisition was consummated on June 30, 2022, the Company's historical consolidated statements of operations for the year ended December 31, 2022 includes six months of income tax benefit attributable to the financing of the 2022 Barnett Assets. Therefore, the pro forma income tax benefit for the year ended December 31, 2022 represents income tax benefit attributable to the financing of the 2022 Barnett Assets for the six months ended June 30, 2022.

(gg) The pro forma adjustments on the Company’s common stock and basic and diluted earnings per share are summarized below (in thousands except per share amounts):

	Year Ended December 31, 2022
Pro forma basic EPS	
Numerator	
Basic combined pro forma net income	$ 472,378
Denominator	
Historical basic weighted average Company shares outstanding	117,318
Pro forma basic weighted average Company shares outstanding	117,318
Pro forma basic net income per share	$ 4.03
Pro forma diluted EPS	
Numerator	
Diluted combined pro forma net income	$ 472,378
Denominator	
Historical diluted weighted average Company shares outstanding	123,980
Pro forma diluted weighted average Company shares outstanding	123,980
Pro forma diluted net income per share	$ 3.81

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our historical consolidated financial statements and related notes included elsewhere in this prospectus. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expectations. "Cautionary Statement Regarding Forward-Looking Statements" and "Risk Factors" (included elsewhere in this prospectus) contain important information. We disclaim any duty to publicly update any forward-looking statements except as otherwise required by applicable law.

In this section, references to "BKV," the "Company," "we," "us," and "our" refer to BKV Corporation and its subsidiaries, unless otherwise indicated or the context otherwise requires. For more information on our organizational structure, see "Note 1 — Business and Basis of Presentation" to our audited consolidated financial statements included elsewhere in this prospectus.

Overview

We are a forward thinking, growth driven energy company focused on creating value for our stockholders through the organic development of our properties as well as accretive acquisitions. Our core business is to produce natural gas from our owned and operated upstream businesses, which we expect to achieve net zero Scope 1 and Scope 2 emissions by the end of 2025, and net zero Scope 1, 2 and 3 emissions from our owned and operated upstream business by the early 2030s. We maintain a "closed-loop" approach to our net zero emissions goal with our four business lines: natural gas production, natural gas gathering, processing and transportation (our "natural gas midstream business"), power generation, and carbon capture, utilization and sequestration ("CCUS"). We are committed to building a vertically integrated business to reduce costs and improve overall commercial optimization of the full value chain. For instance, our natural gas production in the Barnett is gathered and transported through our midstream systems, and we are seeking to establish arrangements to supply our natural gas production directly to the BKV-BPP Power Joint Venture. Our business is operated as one reportable segment.

Recent Developments

Barnett Zero CCUS Project with EnLink

On June 8, 2022, BKV dCarbon Ventures and EnLink reached FID to develop our first high concentration CCUS project and entered into a definitive agreement to dispose of, and geologically sequester, CO_2 generated as a byproduct of the production of our natural gas in the Barnett. This CCUS project, which we refer to as the Barnett Zero Project, will separate CO_2 from substantially all of our EnLink-gathered natural gas production, which we expect to achieve an average sequestration rate of up to approximately 210,000 metric tons of CO_2e per year. We estimate the total investment required by us for the Barnett Zero Project to be between $29.0 and $34.0 million. We are targeting commencement of CO_2 sequestration activities by December 2023, subject to our ability to secure all required permits, at which point we expect this project will be one of the first permanent commercial CO_2 disposal and sequestration projects to come online in the United States.

Exxon Barnett Acquisition

On June 30, 2022, we closed the acquisition (the "Exxon Barnett Acquisition") of natural gas upstream and associated midstream infrastructure in the Barnett from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation, for a total purchase price of $750.0 million, plus additional contingent consideration of up to $50.0 million depending on future natural gas prices. Pursuant to the Exxon Barnett Acquisition, we acquired approximately 165,000 total net acres in the State of Texas that are approximately 99% held by production and located primarily in Tarrant, Johnson and Parker counties, with additional smaller positions in Jack, Wise, Denton, Erath, Hood and Ellis counties. These upstream assets include low decline wells, ideal for delivering consistent cash flow, and high average working interests of approximately 94% in over 2,100 operated wells. The Exxon Barnett Acquisition also included approximately 778 miles of gathering pipelines and compression and processing midstream infrastructure with, as of December 31, 2022, over 450 MMcf/d of throughput capacity and approximately 26 MMcf/d of third-party production being gathered on the system. In connection with the Exxon Barnett Acquisition, we entered into the Term Loan Credit Agreement with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent. The Term Loan Credit Agreement includes up to \$600.0 million of commitments for term loans to be used solely to fund a portion of the purchase price for the Exxon Barnett Acquisition and other costs and expenses associated with the acquisition. As of April 13, 2023, there was \$570.0 million in aggregate principal amount outstanding under the Term Loan Credit Agreement. See "*— Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Term Loan Credit Agreement*" for more information.

CCUS Project Development with Verde CO2

On August 22, 2022, we entered into a development agreement with Verde CO2 to identify, evaluate and develop CCUS projects throughout the United States. We believe our agreement with Verde CO2 will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration. Pursuant to the development agreement, Verde CO2 will be responsible for the sourcing, development, performance and ongoing management of such CCUS projects and BKV dCarbon Ventures will provide funding for such projects. As of April 6, 2023, we have paid \$17.3 million to Verde CO2 under the development agreement, and we expect to invest up to \$250.0 million over the next three years to fund efforts by BKVerde, a subsidiary of BKV dCarbon Ventures, to efficiently identify and evaluate feasible CCUS projects, and to execute on those projects. We expect to fund BKVerde through BKV's cash flow from operations but may also obtain funding from external sources.

Revolving Credit Agreement

On August 24, 2022, we entered into the Revolving Credit Agreement with Bangkok Bank Public Company Limited (New York Branch), as the administrative agent and sole initial lender, and on November 11, 2022, we entered into the First Amendment to Revolving Credit Agreement. The Revolving Credit Agreement includes \$100.0 million of commitments for unsecured revolving loans used for short-term working capital and operating needs. As of April 13, 2023, no amount was outstanding under the Revolving Credit Agreement. See "*— Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Revolving Credit Agreement*" for more additional information regarding the Revolving Credit Agreement.

Cotton Cove CCUS Project

On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of, and geologically sequester CO_2 generated as a byproduct of our natural gas production in the Barnett and will utilize our newly acquired BKV Midstream assets to do so. We have multiple company-owned pore space opportunities for CO_2 injection and we estimate the Cotton Cove Project will geologically sequester up to approximately 45,000 metric tons of CO_2e per year. We currently estimate the total investment required by us for the Cotton Cove Project to be between approximately \$14.0 and \$24.0 million. We are targeting commencement of CO_2 sequestration activities by the first half of 2024, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects under evaluation as described in "*— Our Operations — Carbon Capture, Utilization and Sequestration.*"

Letter of Intent with EEMNA

On November 11, 2022, we entered into a non-binding letter of intent with EEMNA to build a framework for verifiable environmental attributes with the use of carbon credits applied to natural gas energy. Under this framework, we intend to measure, reduce and verify emissions using operational technologies, such as continuous emissions monitoring. In addition, we intend to advance our production of RSG towards a fully carbon-neutral natural gas production which we refer to as Measured Net-Zero ("MNZ") gas. MNZ gas would be achieved by offsetting the estimated emissions associated with the production, gathering and boosting of our RSG as well as the estimated emissions from transmission (and distribution, if applicable) of our sold gas through our CCUS projects, with the requisite volume of offsetting environmental attributes being third-party certified. We believe MNZ provides a fully decarbonized, certified, and qualified fuel that is a differentiated and premium product attractive to LNG buyers, gas utilities, power utilities or other end-users. Project Canary or another environmental certification and ESG data company will reconcile sensing technologies and measure, analyze, and report the environmental attributes of the sequestrated carbon to support the MNZ gas. Under the letter of intent, we anticipate eventually selling MNZ gas to EEMNA for marketing to end-users.

SCB Credit Facility

On February 7, 2023, we increased the limit of the SCB Credit Facility (as defined herein) from $25.0 million to $50.0 million. Of the $50.0 million, $35.0 million is available for cash draw downs, and in the absence of outstanding cash draw downs, the full $50.0 million is available for letters of credit. As of April 13, 2023, we had outstanding letters of credit of $17.4 million against our SCB Credit Facility.

Operational and Financial Highlights

Below are some highlights of our operating and financial results for the years ended December 31, 2022, 2021 and 2020:

- Production of natural gas, NGLs and oil was approximately 279.5 Bcfe, 245.8 Bcfe and 111.7 Bcfe during the years ended December 31, 2022, 2021 and 2020, respectively.
- Average realized product prices, excluding the impact of settled derivatives, were $5.84 per Mcfe, $3.38 per Mcfe and $1.03 per Mcfe for the years ended December 31, 2022, 2021 and 2020, respectively.
- For the years ended December 31, 2022, 2021 and 2020, production revenues were $1.6 billion, $829.7 million and $115.0 million, respectively, and midstream revenues were $12.7 million, $6.9 million and $7.5 million, respectively.
- Lease operating expense was $127.0 million, or $0.45 per Mcfe, $84.3 million, or $0.34 per Mcfe, and $30.1 million, or $0.27 per Mcfe, for the years ended December 31, 2022, 2021 and 2020, respectively.
- Net income attributable to common stockholders for the year ended December 31, 2022 was $410.1 million. Net loss attributable to common stockholders for the years ended December 31, 2021 and 2020 was $170.7 million and $43.8 million, respectively.
- Net cash provided by operating activities for the years ended December 31, 2022 and 2021 was $349.2 million and $358.1 million, respectively. Net cash used in operating activities for the year ended December 31, 2020 was $7.4 million.
- Adjusted EBITDAX was $576.4 million, $281.0 million and $65.1 million for the years ended December 31, 2022, 2021 and 2020, respectively.
- Adjusted Free Cash Flow was $123.9 million, $165.1 million and $56.6 million for the years ended December 31, 2022, 2021 and 2020, respectively.
- Net cash used in investing activities was $865.6 million for the year ended December 31, 2022, $619.4 million of which was used to acquire assets in the Exxon Barnett Acquisition. The remaining cash outflow included $235.4 million attributable to development activities and $10.7 million of other investing activities. Net cash used in investing activities was $161.9 million for the year ended December 31, 2021, $88.4 million of which was used on the initial investment in the BKV-BPP Power Joint Venture. The remaining $73.5 million included $63.9 million attributable to development activities and $7.6 million for developed property and undeveloped acreage acquisition.
- During the year ended December 31, 2021, we paid a dividend to common stockholders of $88.1 million, or $0.75 per share of our common stock. No dividends were paid during the years ended December 31, 2022 and 2020.

Adjusted EBITDAX and Adjusted Free Cash Flow are not financial measures calculated in accordance with accounting principles generally accepted in the United States of America (“GAAP”). See “*Prospectus Summary — Summary Historical and Unaudited Pro Forma Financial Information — Non-GAAP Financial*

Measures" below for a description of each of these measures and a reconciliation of each of these measures to their most directly comparable GAAP measure.

Market Outlook

The natural gas and NGL industry is cyclical and commodity prices are highly volatile. According to the EIA, during the period from January 1, 2021 through December 31, 2022, the Henry Hub natural gas spot price reached a high of $23.86 per MMBtu on February 17, 2021 and a low of $2.43 per MMBtu on April 5, 2021. Henry Hub natural gas spot prices trended higher after the Russia-Ukraine conflict first commenced, rising from $4.78 per MMBtu on February 24, 2022 to a high of $9.85 per MMBtu on August 22, 2022, according to the EIA; however, such prices subsequently dropped to $3.52 on December 31, 2022, as a result of a warmer-than-normal winter.

We expect the natural gas and NGL markets will continue to be volatile in the future. Our revenue, profitability and future growth are highly dependent on the prices we receive for our natural gas and NGL production. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — The volatility of natural gas and NGL prices due to factors beyond our control may materially and adversely affect our business, financial condition or results of operations and our ability to make capital expenditures, meet our debt service obligations and other financial commitments and pay dividends on our common stock.*"

Although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which has continued into 2022, due to a substantial increase in the money supply, a stimulation focused fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 5.4% in June 2021 to 7.0% in December 2021, then rose to 9.1% in June 2022 before dropping back down to 6.5% in December 2022. Global, industry-wide supply chain disruptions have resulted in widespread shortages of labor, materials and services. Such shortages have resulted in our facing significant cost increases for labor, materials and services. We do not expect these shortages and cost increases to reverse in the short term. Typically, as prices for natural gas, NGLs and oil increase, so do associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion to prices. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience further cost increases in our operations, including costs for drill rigs, workover rigs, hydraulic fracturing fleets, tubulars and other well equipment, as well as increased labor costs. If we are unable to recover higher costs through higher commodity prices, our current revenue stream, estimates of future reserves, impairment assessments of natural gas and oil properties, and values of properties in purchase and sale transactions would all be significantly impacted. The increase to prices during 2022 for natural gas, NGLs and oil have more than offset the inflationary related increases to our costs. However, we are monitoring the situation and assessing its impact on our business, including to our customers and our partners. These inflationary pressures are not expected to have a significant impact on our liquidity position when considered in isolation or when combined with the impact of rising interest rates on our variable rate debt. We expect to continue to achieve our business strategy by remaining vigilant in maintaining a disciplined financial strategy and in optimizing the value of our core business.

How We Evaluate Our Business

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

- Adjusted EBITDAX;
- Upstream Reinvestment Rate;
- Adjusted Free Cash Flow;
- Adjusted Free Cash Flow Margin;
- Production Volume; and
- Total Net Leverage Ratio.

Adjusted EBITDAX. We define Adjusted EBITDAX as net income (loss) attributable to BKV Corporation before (i) non-cash derivative gain (loss), (ii) depreciation, depletion, amortization and accretion, (iii) exploration and impairment expense, (iv) (loss) gain on contingent consideration liabilities, (v) interest expense, (vi) interest expense, related party, (vii) income tax benefit (expense), (viii) equity-based compensation expense, (ix) bargain purchase gains, (x) income from equity affiliates, (xi) early settlement of derivative contracts and (xii) other nonrecurring transactions. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by our management and external users of our consolidated financial statements, such as industry analysts, investors, lenders, rating agencies and others to more effectively evaluate our operating performance and results of operations from period to period and against our peers. We believe Adjusted EBITDAX is a useful performance measure because it allows us to effectively evaluate our operating performance and results of operations from period to period and against our peers, without regard to our financing methods, corporate form or capital structure. See "*Prospectus Summary — Summary Historical and Unaudited Pro Forma Financial Information — Non-GAAP Financial Measures*" for a description of Adjusted EBITDAX and for a reconciliation of Adjusted EBITDAX to net loss, its most directly comparable GAAP measure.

Upstream Reinvestment Rate. Upstream Reinvestment Rate for any period is our total cash paid for upstream capital expenditures (excluding leasehold costs and acquisitions) for such period as a percentage of Adjusted EBITDAX for the same period. We use this metric to evaluate from period to period the efficient use of our upstream capital expenditures to maintain or grow our upstream production. We target an Upstream Reinvestment Rate of 40% or less to allow for funding of strategic initiatives. In addition, we target a Maintenance Reinvestment Rate of less than 30%.

Adjusted Free Cash Flow. We define Adjusted Free Cash Flow as net cash provided by (used in) operating activities excluding changes in operating assets and liabilities, less total cash paid for capital expenditures and settlement of contingent consideration (excluding leasehold costs and acquisitions). Adjusted Free Cash Flow is a supplemental non-GAAP financial measure that is used by our management and other external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others to assess our ability to internally fund our capital program, service or incur additional debt and to pay dividends. We believe Adjusted Free Cash Flow is a useful liquidity measure because it allows us and others to compare cash flow provided by operating activities across periods and to assess our ability to internally fund our capital program (including acquisitions), to reduce leverage, fund acquisitions and pay dividends to our stockholders. See "*Prospectus Summary — Summary Historical and Unaudited Pro Forma Financial Information — Non-GAAP Financial Measures*" for a description of Adjusted Free Cash Flow and for a reconciliation of Adjusted Free Cash Flow to net loss and net cash provided by (used in) operating activities, its most directly comparable GAAP measures.

Adjusted Free Cash Flow Margin. We define Adjusted Free Cash Flow Margin as the ratio of Adjusted Free Cash Flow for any period to total revenues, excluding derivative gains and losses, for such period. We use this metric to assess our liquidity relative to our revenues. Adjusted Free Cash Flow Margin illustrates the efficiency with which the Company generates Adjusted Free Cash Flow.

Production Volume. Production Volume for any period is defined as the volume of natural gas, NGLs or oil we extract from our Barnett and NEPA natural gas properties. We use this metric to monitor the efficiency and effectiveness of our upstream operations.

Total Net Leverage Ratio. Total Net Leverage Ratio is the ratio of our total debt less cash and cash equivalents to Adjusted EBITDAX. We use this metric to evaluate our total debt relative to our ability to generate cash through Adjusted EBITDAX. We target a Total Net Leverage Ratio of 1.0x or less to ensure adequate liquidity to meet debt obligations and a low debt burden to protect Adjusted Free Cash Flow. This metric also provides management with a benchmark of debt levels while considering growth opportunities and our ability to manage periods of commodity price volatility.

Factors that Affect Comparability of Our Results of Operations

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

Acquisitions. We intend to continue to grow our operations and financial results through strategic acquisitions like the Devon Barnett Acquisition and the Exxon Barnett Acquisition. Additionally, we may from time to time effect divestitures of certain of our non-core assets. As a result of our Devon Barnett Acquisition, the 2021 acquisition of Temple I by the BKV-BPP Power Joint Venture, as well as our Exxon Barnett Acquisition, our historical reserve, operating and financial data may not be comparable from period to period. For example, for the years ended December 31, 2022, 2021 and 2020, our total revenues were approximately $1.0 billion, $505.7 million and $143.3 million, respectively. As of December 31, 2022 and 2021, our total assets were approximately $2.7 billion and $1.6 billion, respectively, and our total liabilities were $1.5 billion and $865.9 million, respectively. For the years ended December 31, 2022 and 2021, our income from the BKV-BPP Power Joint Venture was approximately $8.5 million and $0.9 million, respectively.

Supply, demand, market risk and the impact on natural gas, NGLs and oil prices. As discussed above in "— *Market Outlook*," the natural gas and oil industry historically has been cyclical with highly volatile commodity prices. Natural gas and oil prices are subject to large fluctuations in response to relatively minor changes in the demand for natural gas, NGLs and oil. Prices are affected by current and expected supply and demand dynamics, including the market disruptions resulting from the Russian-Ukraine war, the impact of the COVID-19 pandemic and related erosion of demand for natural gas, NGLs and oil, U.S. supply growth driven by advances in drilling and completion technologies, and the delay of an agreement on production levels by members of OPEC and other oil producing countries, including Russia, resulting in increased supply in the global market. Other factors impacting supply and demand include weather conditions (including severe weather events), pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, supply chain quality and availability, strength of the U.S. dollar, as well as other factors, the majority of which are outside of our control. These commodity prices are likely to remain volatile in the future.

Public company expenses. We expect to incur incremental, non-recurring costs related to our transition to a publicly traded company, including the costs of this initial public offering and the costs associated with the initial implementation of our Sarbanes-Oxley Section 404 internal control implementation and testing. We also expect to incur additional significant and recurring expenses as a publicly traded corporation, including costs associated with the employment of additional personnel, compliance under the Exchange Act, annual and quarterly reports to common stockholders, registrar and transfer agent fees, national stock exchange fees, audit fees, legal fees, incremental director and officer liability insurance costs and director and officer compensation.

Winter Storm Uri. Our marketing revenues consist of our portion of net profits earned through an agreement we have in place with a third party who operates a commodity trading book. In 2021, we received higher than normal marketing revenues due to the pricing volatility surrounding abnormal weather events. Although the agreement remains in effect, we consider such levels of marketing revenues to be unusual and may not recur in future periods.

Factors that Significantly Affect Our Financial Condition and Results of Operations

We derive almost all of our revenues from the sale of natural gas and NGLs produced from our interests in properties located in the Barnett and NEPA. Our revenues, cash flows from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Natural gas and NGL prices have historically been volatile and may fluctuate widely in the future due to a variety of factors, including, but not limited to, prevailing economic conditions, supply and demand of hydrocarbons in the marketplace and geopolitical events such as wars or natural disasters. In the future, we will also be subject to fluctuations in commodity prices. Sustained periods of low natural gas prices could materially and adversely affect our financial condition, our results of operations, the quantities of natural gas and NGLs that we can economically produce and our ability to access capital.

From time to time, we utilize derivative contracts in connection with our natural gas operations to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas and NGL production. The derivative contracts we enter into consist of swaps, producer collars and basis swaps, subject to master netting agreements with each individual counterparty. While these arrangements are structured to reduce our exposure to commodity price decreases, they can also limit the benefit we might otherwise receive from commodity price increases. For example, for the years ended December 31, 2022, 2021 and 2020, we had derivative gains (losses), net of approximately $(629.7) million, $(383.8) million and $20.8 million, respectively. We elected not to designate our current portfolio of commodity derivative contracts as hedges for accounting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings. See "— *Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk and Hedging Activities*" for additional discussion of our commodity derivative contracts. Our results of operations, liquidity and financial condition would be negatively impacted if natural gas prices were to become depressed or decline materially from current levels, or there is otherwise an unexpected material impact on commodity prices, and we have experienced variance in our results of operations and financial condition due to our hedging transactions.

Businesses engaged in the exploration and production of natural gas and NGLs, such as ours, face the challenge of natural production declines. As initial reservoir pressures are depleted, natural gas and NGL production from a given well naturally decreases. Thus, as does any natural gas exploration and production company, we deplete part of our asset base with each unit of natural gas and NGLs we produce. We attempt to overcome this natural decline by drilling and refracturing to unlock additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production in a cost-effective manner, through development of existing assets and acquisitions. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost-effective manner and to timely obtain drilling permits and regulatory approvals.

Other factors significantly affecting our financial condition and results of operations include, among others:

- success in drilling new wells;
- the availability of attractive acquisition opportunities and our ability to execute them;
- the amount of capital we invest in the leasing and development of our properties;
- facility or equipment availability and unexpected downtime; and
- delays imposed by or resulting from compliance with regulatory requirements.

Sources of Revenues

Currently, substantially all of our revenues are derived from the sale of our natural gas production and the NGLs that are extracted from processing our natural gas, though we also generate a portion of our revenues from the sale of crude oil, midstream and surface operations, a minority equity interest in a midstream system and certain marketing revenue and other income. Our midstream and surface operations primarily support our own exploration and production operations, with revenues generated primarily from fees charged for midstream and surface services, including transportation, freshwater sourcing and disposal and other services to us and our affiliates and, to a lesser extent, third parties.

We sell natural gas, NGLs and oil at specific delivery points. To deliver our products, we may incur third party fees for gathering and transportation. Fees incurred prior to transfer of control are recorded as gathering and transportation expenses. Fees incurred after transfer of control are recognized as a reduction to our transaction price. Pricing of commodities is subject to supply and demand as well as to seasonal, political and other conditions that we generally cannot control. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Natural gas, NGL and oil sale revenues

Approximately 98.4%, 93.3% and 93.9% of our total revenues, excluding net derivative (losses) gains, for the years ended December 31, 2022, 2021 and 2020, respectively, were derived through the production and sale of natural gas, NGLs and oil. Production of these resources occurs exclusively within the Barnett and NEPA. The following table presents the breakdown of our revenues from the production and sale of natural gas, NGLs and oil for periods presented:

	Year Ended December 31,		
	2022	2021	2020
Natural gas sales	80%	72%	89%
NGL sales	19%	27%	10%
Oil sales	1%	1%	1%

Our revenues are influenced by production volumes as well as commodity prices. The following table presents our historical production volumes for the periods presented:

	Year Ended December 31,		
	2022	2021	2020
Production Data			
Natural gas (MMcf)	217,585	186,055	96,159
NGLs (MBbls)	10,187	9,829	2,565
Oil (MBbls)	140	123	29
Total volumes (MMcfe)	279,547	245,767	111,722
Average daily total volumes (MMcfe/d)	765.9	673.3	306.1

Midstream revenues

Approximately 0.8%, 0.7% and 6.1% of our total revenues, excluding net derivative (losses) gains, for the years ended December 31, 2022, 2021 and 2020, respectively, were generated from our midstream operations, including our approximate 29.4% non-operated interest in a midstream system operated by Repsol (our "Repsol Midstream Interest"). Midstream revenues during 2021 and 2020 were generated exclusively from our Repsol Midstream Interest. During 2022, in addition to revenues from our Repsol Midstream Interest, we began to generate midstream revenues from midstream assets acquired in the Exxon Barnett Acquisition, which we operate. Revenues from the non-operated Repsol Midstream Interest and our operated midstream assets are recognized when services are rendered based on quantities transported and measured according to the underlying contracts.

Marketing revenues

Approximately 0.7%, 5.9% and zero of our total revenues, excluding net derivative (losses) gains, for the years ended December 31, 2022, 2021 and 2020, respectively, consists of our portion of net profits earned through an agreement with Concord Energy, LLC, the third-party marketer of substantially all of our natural gas production. Pursuant to such agreement, which we entered into in 2021, we receive a fixed percentage of all net income realized in the resale of our and other producers' hydrocarbons. In February 2021, we received higher than normal marketing revenues due to the pricing volatility surrounding the events of Winter Storm Uri. Although the agreement remains in effect, we consider such levels of marketing revenues to be unusual and may not recur in future periods.

Realized Commodity Prices

Our results of operations are heavily influenced by commodity prices. Natural gas, NGL and oil prices have historically been volatile and during 2022 experienced near record-high levels. On December 31, 2022, the Henry Hub natural gas spot price was $4.06 per MMBtu, and during the period from January 1, 2021 through December 31, 2022, natural gas prices reached a high of $23.86 per MMBtu and a low of $2.43 per MMBtu. In early 2023, natural gas commodity prices decreased significantly, and we expect this lower natural gas commodity pricing environment to continue at least into the second quarter of 2023. A future decline in commodity prices may adversely affect our business, financial condition and results of operations. Lower commodity prices may not only decrease our revenues, but also the amount of natural gas and oil that we can produce economically.

NYMEX Henry Hub, for gas prices, and NYMEX WTI, for oil prices, are widely used benchmarks for the pricing of natural gas and oil in the United States. The price we receive for our natural gas and oil production is generally different than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors. As such, our revenues are sensitive to the price of the underlying commodity to which they relate. The following is a comparison of average pricing excluding and including the effects of derivatives:

	Year Ended December 31,		
	2022	2021	2020
Average Prices			
Natural gas (Mcf):			
Average NYMEX Henry Hub price	$ 6.47	$ 3.84	$ 2.08
Average natural gas realized price (excluding derivatives)	$ 6.47	$ 3.21	$ 1.06
Average natural gas realized price (including derivatives)	$ 3.72	$ 2.29	$ 1.17
Differential to NYMEX Henry Hub	$ (0.45)	$ (0.63)	$ (1.02)
NGLs (Bbl):			
Average NYMEX WTI price	$ 95.03	$ 67.92	$ 39.40
Average NGL realized price (excluding derivatives)	$ 30.58	$ 22.90	$ 4.66
Average NGL realized price (including derivatives)	$ 27.78	$ 16.03	$ 4.66
Differential to NYMEX WTI	$ (64.45)	$(45.02)	$(34.74)
Oil (Bbl):			
Average NYMEX WTI price	$ 95.03	$ 67.92	$ 39.40
Average oil realized price (excluding derivatives)	$ 84.76	$ 61.46	$ 46.67
Average oil realized price (including derivatives)	$ 84.76	$ 61.46	$ 46.67
Differential to NYMEX WTI	$ (10.27)	$ (6.46)	$ 7.27
High and low NYMEX prices:			
Oil (Bbl):			
High	$123.64	$ 84.65	$ 63.27
Low	$ 71.05	$ 47.62	$(37.63)
Natural gas (Mcf):			
High	$ 9.85	$ 23.86	$ 3.35
Low	$ 3.46	$ 2.43	$ 1.48

Commodity Price Risk and Derivatives and Hedging Activities

The volatility of energy markets makes it extremely difficult to predict future natural gas, NGL and oil price movements with any certainty, and our results of operations and cash flows are impacted by changes in market prices for natural gas, NGLs and oil. Lower natural gas, NGL and oil prices may reduce the amount of natural gas and oil that we can produce economically. This may also result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, successful efforts accounting rules may require us to recognize impairment expense as a non-cash charge to earnings, and to the carrying value of our natural gas properties.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our production. In most of our current positions, our hedging activity may also reduce our ability to benefit from increases in commodity prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices, and conversely, we will recognize gains to the extent our derivatives contract prices are higher than market prices. The price we receive for sales of our natural gas, NGLs and oil is generally less than the NYMEX prices because of adjustments for basis, relative quality and other factors.

During the year ended December 31, 2022, our derivative settlements decreased our natural gas revenue by $501.7 million and decreased our NGL revenue by $28.5 million, and early terminations of natural gas derivative contracts during the year ended December 31, 2022 decreased revenue by an additional $158.3 million. During the year ended December 31, 2021, our derivative settlements decreased our natural gas revenue by $170.2 million and decreased our NGL revenue by $67.6 million, and early terminations of derivative contracts during the year ended December 31, 2021 decreased natural gas revenue by an additional $30.9 million. During the year ended December 31, 2020, our derivative settlements increased natural gas revenue by $7.7 million, and early terminations of derivative contracts increased revenue by an additional $2.7 million for a total increase of $10.4 million.

The following table summarizes our outstanding natural gas derivative positions as of December 31, 2022. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments.

Instrument	MMBtu	Weighted Average Price (USD)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value as of December 31, 2022 (in thousands)
2023					
Swap	47,145,000	$ 3.90			$ (13,755)
Collars	41,250,000		$ 2.85	$ 3.75	$ (29,474)

The following table represents natural gas basis derivatives based on the applicable basis reference price listed below:

Instrument	Basis Reference Price	MMBtu	Weighted Average Basis Differential	Fair Value as of December 31, 2022 (in thousands)
2023				
Swap	Transco 85	9,000,000	$ 0.46	$ 277
Swap	TETCO M3	590,000	$ 10.68	$ 2,149
Swap	NGPL TXOK Basis	22,470,000	$ (0.47)	$ 993
2024				
Swap	NGPL TXOK Basis	12,840,000	$ (0.54)	$ 816

The following table represents natural gas liquids commodity derivatives for contracts, by contract type, expiring throughout the year ending December 31, 2023 based on the applicable index listed below:

Instrument	Commodity Reference Price	Volumes	Weighted Average Price (USD)	Fair Value as of December 31, 2022 (In thousands)
Swap	OPIS Purity Ethane Mont Belvieu	38,325,000	$ 0.23	$ (1,743)
Swap	OPIS IsoButane Mont Belvieu Non-TET	3,832,500	$ 0.80	$ (853)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	3,832,500	$ 0.80	$ (698)
Swap	OPIS Pentane Mont Belvieu Non-TET	7,665,000	$ 1.28	$ (1,948)
Swap	OPIS Propane Mont Belvieu Non-TET	22,995,000	$ 0.72	$ (1,872)

Instrument	Commodity Reference Price	Gallons	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value as of December 31, 2022 (in thousands)
Collar	OPIS IsoButane Mont Belvieu Non-TET	9,198,000	$ 0.95	$ 1.09	$ 91

Principal Components of Cost Structure

Lease operating and workover

Lease operating and workover expenses reflect the costs incurred to maintain our production. Lease operating expenses represent the costs incurred for field employee salaries, saltwater disposal, repairs and maintenance, and other standard operating expenses. Workover expenses include those costs incurred to perform more substantial maintenance or remedial treatments on a well to restore or enhance production. Cost levels for certain of these expenses vary based on the volume of production, among other factors.

Taxes other than income

Taxes other than income consist of production taxes, severance taxes, impact fees and ad valorem taxes. Production and severance taxes are paid on produced natural gas and oil based on a percentage of the market value or sales prices of the natural gas and oil or at fixed per-unit rates established by state authorities. Impact fees are based on drilling activities and natural gas market prices. We pay ad valorem taxes based on the value of our reserves as well as the value of property and equipment.

Gathering and transportation

Gathering and transportation expenses are incurred in connection with the natural gas, NGL and oil gathering and transportation contracts we enter into with third parties. Pursuant to these contracts, third parties agree to deliver the natural gas, NGLs and oil we produce to our customers for a fee. The fees incurred prior to control transfer are classified as gathering and transportation expenses on the consolidated statements of operations, whereas any fees incurred after transfer of control are included as a reduction of the associated revenues.

Accretion of asset retirement obligations

Accretion of asset retirement obligations reflects the expense related to accretion of our asset retirement obligations. Our obligations are accreted using the interest method over the period from initial measurement to the expected timing of settlement and are measured using our credit-adjusted risk-free rate applied when the liability was initially measured.

Depreciation, depletion, amortization and accretion

Depreciation, depletion and amortization reflects the systematic expensing of the costs capitalized in connection with our costs to acquire, explore and develop natural gas, NGLs and oil. We use the successful efforts method of accounting for natural gas producing activities. Accordingly, we capitalize all costs associated with our acquisition, drilling, development, and retirement efforts and all successful exploration efforts and allocate these costs using the units of production method. Depreciation of midstream assets and other property and equipment is computed over an asset’s estimated useful life using a straight-line basis.

Accretion of asset retirement obligations reflects the expense related to the accretion of our asset retirement obligations. Our obligations are accreted using the interest method over the period from initial measurement to the expected timing of settlement and are measured using our credit-adjusted risk-free rate applied when the liability was initially measured.

For any contract deemed to include a leased asset, such as compressors and other equipment used in our upstream operations, that asset is capitalized on the balance sheet as a right-of-use (“ROU”) asset and a corresponding lease liability is recorded at the present value of the known future minimum payments of the contract using a discount rate on the date of commencement. Accretion of lease liabilities reflects the periodic accretion expense associated with the increase in the present value of the lease liability over the life of the underlying lease.

Included in depreciation, depletion, amortization and accretion, exploration costs are costs related to unsuccessful leasing efforts, as well as geological and geophysical costs, including seismic costs, costs of unsuccessful exploratory dry holes and costs of other exploratory activities. Impairment costs include impairment and costs associated with leases expirations, impairment of design and initial costs related to pads that are no longer planned to be placed into service and impairment of proved properties due to lower future commodity prices. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks and future plans to develop the acreage. We also record impairment charges for proved properties on a geological reservoir basis when events or changes in circumstances indicate that a property's carrying amount may not be recoverable.

General and administrative

General and administrative expenses typically represent costs for payroll and benefits for our work force, equity-based compensation expense, integration support, consulting fees, costs incurred to maintain our headquarters, and costs incurred for various legal proceedings which arise through the normal course of business, among others.

Gain (loss) on contingent consideration liabilities

Pursuant to the separate purchase agreements associated with the Devon Barnett Acquisition and the Exxon Barnett Acquisition, we agreed to earnout obligations pursuant to which we agreed to make certain contingent consideration payments based on future prices of natural gas. As of December 31, 2022, we paid Devon Energy $65.0 million in contingent consideration payments. On January 13, 2023, we paid Devon Energy an additional $65.0 million in contingent consideration payments. We have not paid any contingent consideration payments to Exxon Mobil Corporation as of December 31, 2022. These unpaid future contingent consideration payments are stated at fair value on our consolidated balance sheets, with changes in fair value recorded in the consolidated statements of operations.

Interest expense and related party interest expense

We finance a portion of our capital expenditures, working capital requirements and acquisitions with borrowings under the Subordinated Intercompany Loan Agreements, Working Capital Facilities and the Term Loan Credit Agreement. As a result, we incur interest expense that is affected by both fluctuations in interest rates under our credit facilities and our financing decisions. We have not historically utilized interest rate swaps to mitigate fluctuations in interest rates.

Income tax benefit (expense)

We are subject to state and U.S. federal income taxes. The difference between our financial statement income tax expense and our U.S. federal income tax liability is primarily due to the differences in the tax and financial statement treatment of natural gas properties and the deferral of unsettled commodity derivative gains and losses for tax purposes until they are settled. We also pay certain state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We record deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets.

In the future, we expect we will be able to realize an additional income tax benefit from Section 45Q tax credits. For facilities placed in service on or after February 9, 2018 and before January 1, 2023, Section 45Q of the Code generally provides the capturing parties a tax credit that escalates until 2026, when it reaches $50 per ton for CO_2 directly stored in geologic formations, annually escalating for inflation thereafter. For facilities placed in service after December 31, 2022, the credit amount is increased to $85 per ton, subject to satisfaction or non-application of certain prevailing wage and apprenticeship requirements (or $17 per ton if such prevailing wage and apprenticeship requirements are not satisfied), with adjustments for inflation after 2026. In either case, the Section 45Q tax credits are available for a 12-year period for qualifying facilities that begin construction before January 1, 2033.

Results of Operations

The following tables present selected financial and operating information for the periods presented:

(In thousands)	Year Ended December 31, 2022	2021	2020
Revenues and other operating income			
Natural gas sales	$1,310,339	$ 597,050	$101,758
NGL sales	311,542	225,135	11,952
Oil sales	11,866	7,560	1,333
Midstream revenues	12,676	6,917	7,458
Derivative gains (losses), net	(629,701)	(383,847)	20,755
Marketing revenues	11,001	52,616	—
Other	2,799	251	33
Total revenues and other operating income	1,030,522	505,682	143,289
Operating expenses			
Lease operating and workover	135,064	88,105	31,260
Taxes other than income	114,668	45,650	5,151
Gathering and transportation	208,758	173,587	—
Depreciation, depletion, amortization and accretion	118,909	92,277	87,343
General and administrative	148,559	85,740	29,442
Total operating expenses	725,958	485,359	153,196
Income (loss) from operations	304,564	20,323	(9,907)
Other income and expense			
Bargain purchase gain	170,853	—	—
Gain on settlement of litigation	16,866	—	—
Gain (loss) on contingent consideration liabilities	6,632	(194,968)	7,135
Earnings from equity affiliate	8,493	910	—
Interest income	1,143	8	121
Interest expense	(26,322)	—	—
Interest expense, related party	(10,846)	(2,134)	(1,713)
Other income	1,411	872	—
Income (loss) before income taxes	472,794	(174,989)	(4,364)
Income tax benefit (expense)	(62,652)	40,526	(38,982)
Net income (loss) attributable to BKV Corporation	$ 410,142	$(134,463)	$ (43,346)
Less accretion of preferred stock to redemption value	—	(3,745)	—
Less preferred stock dividends	—	(9,900)	(460)
Less deemed dividend on redemption of preferred stock	—	(22,606)	—
Net income (loss) attributable to common stockholders	$ 410,142	$(170,714)	$ (43,806)

Comparison of the Years Ended December 31, 2022 and 2021

Operating Revenues

Our operating revenues include revenues from the sale of natural gas, NGLs and oil, midstream revenues, gains and losses on our derivative contracts, marketing revenues and other revenues. The following table provides information on our revenues for the periods presented:

(In thousands, other than percentages)	Year Ended December 31, 2022	2021	$ Change	% Change
Revenues				
Natural gas revenues	$1,310,339	$ 597,050	$ 713,289	*
NGL revenues	311,542	225,135	86,407	38%
Oil revenues	11,866	7,560	4,306	57%
Midstream revenues	12,676	6,917	5,759	83%
Derivative (losses) gains, net	(629,701)	(383,847)	(245,854)	64%
Marketing revenues	11,001	52,616	(41,615)	(79)%
Other	2,799	251	2,548	*
Total revenues and other operating income	$1,030,522	$ 505,682		

* *Percentage not meaningful*

Natural gas revenues

Our natural gas revenues increased by approximately $713.3 million to $1.3 billion for the year ended December 31, 2022 from $597.1 million for the year ended December 31, 2021. Higher production volumes, primarily from the 2022 Barnett Assets, during the year ended December 31, 2022 accounted for a $101.2 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price). The impact of commodity price increases, excluding the effect of derivative settlements, provided a $612.1 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current year production volumes).

NGL revenues

Our NGL revenues increased by approximately $86.4 million to $311.5 million for the year ended December 31, 2022 from $225.1 million for the year ended December 31, 2021. Higher production volumes, primarily from the 2022 Barnett Assets, during the year ended December 31, 2022 accounted for a $8.2 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price). The impact of commodity price increases, excluding the effect of derivative settlements, provided a $78.2 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

Oil revenues

Our oil revenues increased by approximately $4.3 million to $11.9 million for the year ended December 31, 2022 from $7.6 million for the year ended December 31, 2021. Higher production volumes during the year ended December 31, 2022 accounted for a $1.1 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price). This increase was also due to the impact of commodity price increases, excluding the effect of derivative settlements, which provided a $3.2 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

Midstream revenues

Our midstream revenues increased by approximately $5.8 million to $12.7 million for the year ended December 31, 2022 from $6.9 million for the year ended December 31, 2021. This increase was primarily due to the midstream assets acquired in the Exxon Barnett Acquisition, slightly offset by decreases in the associated production of natural gas properties our legacy midstream assets support.

Derivative (losses) gains, net

For the year ended December 31, 2022, we had a loss on derivative contracts of $629.7 million compared to a loss on derivative contracts of $383.8 million for the year ended December 31, 2021. The increased loss for the year ended December 31, 2022 is attributable to increases in underlying commodity prices and volatility in energy markets, which resulted in higher realized losses on derivative contracts as well as $158.3 million of early terminations. This was offset by unrealized gains on derivative contracts of $58.8 million during the year ended December 31, 2022.

Marketing revenues

Our marketing revenues decreased by approximately $41.6 million to $11.0 million for the year ended December 31, 2022 from $52.6 million for the year ended December 31, 2021. Our marketing revenues are derived under our marketing agreement with a third party pursuant to which we receive a fixed percentage of all net income realized in the resale of our and other producers' hydrocarbons. The decrease in marketing revenues was primarily due to the pricing volatility surrounding the events of Winter Storm Uri, which resulted in $48.7 million of revenues for the year ended December 31, 2021. There were no events of this nature during the year ended December 31, 2022.

Other operating income

We generate a portion of our revenues from a management fee from the BKV-BPP Power Joint Venture. Our other revenues were approximately $2.8 million for the year ended December 31, 2022 as compared to $0.3 million for the year ended December 31, 2021.

Operating Expenses

Our operating expenses reflect costs incurred in the development, production and sale of natural gas, NGLs and oil. The following table provides information on our operating expenses:

(In thousands, other than percentages and average costs)	Year Ended December 31, 2022	Year Ended December 31, 2021	$ Change	% Change
Operating expenses				
Lease operating and workover	$ 135,064	$ 88,105	$46,959	53%
Taxes other than income	114,668	45,650	69,018	*
Gathering and transportation	208,758	173,587	35,171	20%
Depreciation, depletion, amortization and accretion	118,909	92,277	26,632	29%
General and administrative	148,559	85,740	62,819	73%
Total operating expense	$ 725,958	$ 485,359		
Average costs per Mcfe				
Lease operating and workover	$ 0.48	$ 0.36	$ 0.12	33%
Taxes other than income	0.41	0.19	0.22	*
Gathering and transportation	0.75	0.71	0.04	6%
Depreciation, depletion, amortization and accretion	0.43	0.37	0.06	16%
General and administrative	0.53	0.35	0.18	51%
Total	$ 2.60	$ 1.98		

* *Percentage not meaningful*

Lease operating and workover

The following table summarizes our components of lease operating expenses for the periods presented:

	Year Ended December 31,					
	2022		2021		$ Change	% Change
(In thousands, other than percentages and average costs)	Amount	Per Mcfe	Amount	Per Mcfe		
Lease operating expenses	$126,953	$ 0.45	$84,303	$ 0.34	$42,650	51%
Workover expenses	8,111	0.03	3,802	0.02	4,309	*
Total lease operating and workover expense	$135,064	$ 0.48	$88,105	$ 0.36	$46,959	53%

* *Percentage not meaningful*

Lease operating and workover expenses were $135.1 million, or $0.48 per Mcfe, for the year ended December 31, 2022, which was an increase of $47.0 million, or 53%, from $88.1 million, or $0.36 per Mcfe, for the year ended December 31, 2021. The increase in lease operating and workover expenses during the year ended December 31, 2022 compared to the same period in 2021 was primarily due to the Exxon Barnett Acquisition, which closed on June 30, 2022. The acquired operations drove $33.1 million of incremental lease operating and workover expenses during the year ended December 31, 2022. The remaining $13.9 million of increased lease operating and workover expenses was driven by a $4.5 million increase in labor costs, a $3.4 million increase in disposal costs, and $2.8 million increase in operating equipment costs. We had other increases of approximately $3.2 million of individually immaterial net increases in other direct production costs incurred in connection with our operations.

Taxes other than income

Taxes other than income were $114.7 million, or $0.41 per Mcfe, for the year ended December 31, 2022, which was an increase of $69.0 million from $45.7 million, or $0.19 per Mcfe, for the year ended December 31, 2021. The increase in taxes other than income during the year ended December 31, 2022 compared to 2021 was primarily due to increased natural gas and NGL production taxes associated with our operations from the 2020 Barnett Properties, which accounted for $33.7 million of the increase, as certain ad valorem and production taxes are not applicable to our NEPA natural gas properties. Property taxes related to our NEPA natural gas properties and our 2020 Barnett Assets increased by $13.0 million during 2022 compared to 2021. Ad valorem, production and property taxes related to the Exxon Barnett Acquisition accounted for the remainder of the increase in 2022 compared to 2021.

Gathering and transportation

Gathering and transportation expenses were $208.8 million, or $0.75 per Mcfe, for the year ended December 31, 2022, which was an increase of $35.2 million, from $173.6 million, or $0.71 per Mcfe, for the year ended December 31, 2021. The increase was primarily due to certain gathering and transportation contracts from the Devon Barnett Acquisition, expiring in 2021, which required us to net the gathering and transportation fees with our natural gas, NGL and oil sales. Upon expiration, the contracts were replaced and expenses under the new contracts are presented as gathering and transportation expenses, accounting for approximately $19.0 million of gathering and transportation expenses during the year ended December 31, 2022. In addition, the Exxon Barnett Acquisition accounted for $10.3 million of the increase. The remainder of the increase in gathering and transportation expenses during the year ended December 31, 2022 compared to the same period in 2021 was due to an increase in volumes of $2.4 million and an increase in contractual rates with a third party of $1.5 million.

Depreciation, depletion, amortization and accretion

Depreciation, depletion, amortization and accretion was $118.9 million, or $0.43 per Mcfe, for the year ended December 31, 2022, which was an increase of $26.6 million, or 29%, from $92.3 million, or $0.37 per Mcfe, for the year ended December 31, 2021. The increase in depreciation, depletion, amortization and accretion during the year ended December 31, 2022, compared to the year ended December 31, 2021, was primarily due to the Exxon Barnett Acquisition, which accounted for an additional $22.9 million of depreciation, depletion, amortization and accretion expense during the year ended December 31, 2022. The remaining $3.7 million consisted of individually immaterial increases.

General and administrative

General and administrative expenses were $148.6 million, or $0.53 per Mcfe, for the year ended December 31, 2022, which was an increase of $62.8 million, or 73%, from $85.7 million, or $0.35 per Mcfe, for the year ended December 31, 2021. The increase in general and administrative expenses during the year ended December 31, 2022 compared to the year ended December 31, 2021 was primarily due to the Exxon Barnett Acquisition, which provided $14.5 million of additional general and administrative costs and $18.5 million in incremental costs which included direct transaction costs. Also during the year ended December 31, 2022, we had an increase in costs of $20.7 million related to equity-based compensation, employee wages and contract labor and fees compared to the same period in 2021. During 2022, we entered into an agreement with Verde CO2 and incurred $13.0 million for the management of BKVerde, as compared to an immaterial amount during 2021.

Other income and expenses

Bargain purchase gain. Bargain purchase gain increased to $170.9 million for the year ended December 31, 2022 from zero for the year ended December 31, 2021. The Exxon Barnett Acquisition resulted in a bargain purchase gain, which was primarily caused by the increase in commodity pricing from the date the acquisition was originally negotiated through the closing date. Because the value of the purchase consideration transferred was less than the fair value of the assets acquired and liabilities assumed as of the closing date of the Exxon Barnett Acquisition, we recognized a bargain purchase gain for the difference.

Gain (loss) on contingent consideration liabilities. We recognized a gain on contingent consideration liabilities accruing as an earnout obligation under the purchase agreements executed in connection with the Devon Barnett Acquisition and the Exxon Barnett Acquisition. The gain on contingent consideration liabilities was $6.6 million for the year ended December 31, 2022, which was an increase of $201.6 million from the $195.0 million loss for the year ended December 31, 2021. The $6.6 million gain in 2022 compared to the $195.0 million loss in 2021 is primarily attributable to the gain on contingent consideration liabilities with the Devon Barnett Acquisition of $5.1 million. Decreases in forward curve commodity pricing for natural gas (NYMEX) and oil (WTI) assumptions used in the Monte Carlo simulations during the year ended December 31, 2022, decreased the fair market value of the liability. The year ended December 31, 2021 showed increases in forward curve commodity pricing for natural gas and oil causing the fair value of the contingent consideration to increase the associated liability. The remaining $1.6 million of the current period gain on contingent consideration liabilities is attributed to the 2022 Exxon Barnett Acquisition, which is also driven by decreases in forward curve commodity pricing from the acquisition date.

Gain on settlement of litigation. Gain on settlement of litigation increased to $16.9 million for the year ended December 31, 2022 from zero compared to the same period in 2021 due to the settlement of a dispute between us and an operator related to a midstream gathering system. We agreed to settle with the operator in February 2022, receiving $35.0 million in the settlement. Of the $35.0 million received, $18.1 million was deemed the collection of accounts receivable. The remaining $16.9 million has been recognized as a gain on settlement of litigation on our consolidated statements of operations.

Interest expense. Interest expense was $26.3 million for the year ended December 31, 2022, which was an increase from zero compared to the same period in 2021. The increase in interest expense during year ended December 31, 2022 was driven from our Term Loan Credit Agreement and Revolving Credit Facilities, which did not carry balances during the year ended December 31, 2021.

Interest expense, related parties. Interest expense from related parties was $10.8 million for the year ended December 31, 2022, which was an increase of $8.7 million from $2.1 million for the year ended December 31, 2021. The increase was due to increased borrowings with BNAC of $75.0 million under the $75 Million Loan Agreement and nine months of outstanding debt on the $116.0 million loan under the $116 Million Loan Agreement (as defined herein) during 2022, compared to three months in 2021.

Income tax benefit (expense). Income tax expense was $62.7 million for the year ended December 31, 2022, which was a change of $103.2 million from an income tax benefit of $40.5 million compared to the same period in 2021. The year-over-year change was due primarily to the higher pre-tax income during the year ended December 31, 2022, compared to a pre-tax loss during the year ended December 31, 2021.

Earnings from equity affiliates. Earnings from equity affiliates was $8.5 million for the year ended December 31, 2022, which was a change of $7.6 million from $0.9 million compared to the same period in 2021. Earnings from equity affiliates is related to our investment and proportionate share in the income or losses of the BKV-BPP Power Joint Venture, which we entered into in November 2021.

Comparison of the Years Ended December 31, 2021 and 2020

Operating Revenues

Our operating revenues include revenues from the sale of natural gas, NGLs and oil, midstream revenues, gains and losses on our derivative contracts, marketing revenues and other revenues. The following table provides information on our revenues for the periods presented:

	Year Ended December 31,			
(In thousands)	**2021**	**2020**	**$ Change**	**% Change**
Revenues				
Natural gas revenues	$ 597,050	$101,758	$ 495,292	*
NGL revenues	225,135	11,952	$ 213,183	*
Oil revenues	7,560	1,333	$ 6,227	*
Midstream revenues, net	6,917	7,458	$ (541)	(7)%
Derivative (losses) gains, net	(383,847)	20,755	$(404,602)	*
Marketing revenues	52,616	—	$ 52,616	*
Other	251	33	$ 218	*
Total revenues and other operating income	$ 505,682	$143,289		

* *Percentage not meaningful*

Natural gas revenues

Our natural gas revenues increased by approximately $495.3 million to $597.1 million for the year ended December 31, 2021 from $101.8 million for the year ended December 31, 2020. Higher production volumes during the year ended December 31, 2021 accounted for a $95.1 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior period-end average price) driven by the inclusion of a full year of production from our 2020 Barnett Assets during 2021. Changes in commodity price, excluding the effect of derivative settlements, provided a $400.2 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

NGL revenues

Our NGL revenues increased by approximately $213.2 million to $225.1 million for the year ended December 31, 2021 from $12.0 million for the year ended December 31, 2020. Higher production volumes, primarily from the 2022 Barnett Assets, during the year ended December 31, 2021 accounted for a $33.8 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year-end average price) driven by the inclusion of a full year of production from our 2020 Barnett Assets during 2021. Changes in commodity price, excluding the effect of derivative settlements, accounted for a $179.4 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

Oil revenues

Our oil revenues increased by approximately $6.2 million to $7.6 million for the year ended December 31, 2021 from $1.3 million for the year ended December 31, 2020. Higher production volumes during the year ended December 31, 2021 accounted for a $4.4 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior period-end average price) driven by the inclusion of a full year of production from our 2020 Barnett Assets during 2021. Changes in commodity price, excluding the effect of derivative settlements, provided a $1.8 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

Midstream revenues

Our non-operated midstream revenues decreased by approximately $0.5 million, or 7%, to $6.9 million for the year ended December 31, 2021 from $7.5 million for the year ended December 31, 2020. This decrease was primarily due to decreases in the associated production of natural gas properties the midstream assets support.

Derivative (losses) gains, net

For the year ended December 31, 2021, we had a loss on derivative contracts of $383.8 million compared to a gain on derivative contracts of $20.8 million for the year ended December 31, 2020. The loss for the year ended December 31, 2021 is attributable to increases in underlying commodity prices and volatility in energy markets, which resulted in higher realized and unrealized losses on derivative contracts.

Marketing revenues

Our marketing revenues increased by approximately $52.6 million, to $52.6 million for the year ended December 31, 2021 from zero for the year ended December 31, 2020. Our marketing revenues are derived under our marketing agreement with a third party pursuant to which we receive a fixed percentage of all net income realized in the resale of our and other producers' hydrocarbons. The increase in marketing revenues was primarily due to the pricing volatility surrounding the events of Winter Storm Uri, which resulted in $48.7 million of revenues for the year ended December 31, 2021.

Other revenues

We generate a portion of our revenues from other sources including surface and midstream operations and a management fee from the BKV-BPP Power Joint Venture. Our other revenues were approximately $0.3 million for the year ended December 31, 2021 compared to a negligible amount for the year ended December 31, 2020. The increase was minimal year-over-year.

Operating Expenses

Our operating expenses reflect costs incurred in the development, production and sale of natural gas, NGLs and oil. The following table provides information on our operating expenses:

	Year Ended December 31,			
(In thousands, other than percentages and average costs)	**2021**	**2020**	**$ Change**	**% Change**
Operating expenses				
Lease operating and workover	$ 88,105	$ 31,260	$ 56,845	*
Taxes other than income	45,650	5,151	40,499	*
Gathering and transportation	173,587	—	173,587	*
Depreciation, depletion, amortization and accretion	92,277	87,343	4,934	6%
General and administrative	85,740	29,442	56,298	*
Total operating expense	$485,359	$153,196		
Average costs per Mcfe				
Lease operating and workover	$ 0.36	$ 0.28	$ 0.08	29%
Taxes other than income	0.19	0.05	0.14	*
Gathering and transportation	0.71	—	0.71	*
Depreciation, depletion, amortization and accretion	0.37	0.79	(0.42)	(53)%
General and administrative	0.35	0.26	0.09	35%
Total	$ 1.98	$ 1.38		

* *Percentage not meaningful*

Lease operating and workover

The following table summarizes our components of lease operating expenses for the periods presented:

	Year Ended December 31,					
	2021		2020			
(In thousands, other than percentages and average costs)	Amount	Per Mcfe	Amount	Per Mcfe	$ Change	% Change
Lease operating expenses	$84,303	$ 0.34	$30,136	$ 0.27	$54,167	*
Workover expenses	3,802	0.02	1,124	0.01	2,678	*
Total lease operating and workover expense	$88,105	$ 0.36	$31,260	$ 0.28	$56,845	

* *Percentage not meaningful*

Lease operating and workover expenses were $88.1 million, or $0.36 per Mcfe, for the year ended December 31, 2021, which was an increase of $56.8 million from $31.3 million, or $0.28 per Mcfe, for the year ended December 31, 2020. The increase in lease operating and workover during 2021 compared to 2020 was due to the Devon Barnett Acquisition, which included a full year of activity for the year ended December 31, 2021, compared to three months of activity in 2020.

Taxes other than income

Taxes other than income were $45.7 million, or $0.19 per Mcfe, for the year ended December 31, 2021, which was an increase of $40.5 million from $5.2 million, or $0.05 per Mcfe, for the year ended December 31, 2020. The increase in taxes during 2021 compared to 2020 was due to the Devon Barnett Acquisition, which included a full year of activity for the year ended December 31, 2021, compared to three months of activity in 2020. Properties acquired in the Devon Barnett Acquisition are subject to certain ad valorem and severance taxes which are not applicable to our NEPA natural gas properties.

Gathering and transportation

Gathering and transportation expenses were $173.6 million, or $0.71 per Mcfe, for the year ended December 31, 2021. No gathering and transportation expenses were incurred for the year ended December 31, 2020. For the year ended December 31, 2021, the expenses generated from gathering and transportation were due to new contracts entered into from our Devon Barnett Acquisition. Pursuant to these new contracts, fees for gathering and transportation of natural gas in the Barnett region are incurred prior to transfer of control of our natural gas production. The fees for the gathering and transportation of natural gas in our legacy NEPA region are incurred subsequent to transfer of control, and therefore, included in revenues.

Depreciation, depletion, amortization and accretion

Depreciation, depletion, amortization and accretion was $92.3 million, or $0.37 per Mcfe, for the year ended December 31, 2021, which was an increase of $4.9 million, or 6%, from $87.3 million, or $0.79 per Mcfe, for the year ended December 31, 2020. The increase was primarily driven by additional accretion expense as compared to 2020 of $6.8 million from the additional asset retirement obligations associated with the 2020 Barnett Properties.

This was offset by a decrease in depreciation, depletion and amortization expenses of $1.9 million during the year ended December 31, 2021, as compared to 2020 due to an increase in proved reserves, which lowered our depletion rate.

General and administrative

General and administrative expenses were $85.7 million, or $0.35 per Mcfe, for the year ended December 31, 2021, which was an increase of $56.3 million from $29.4 million, or $0.26 per Mcfe, for the year ended December 31, 2020. The increase in general and administrative expenses during 2021 compared to 2020 was primarily due to equity-based compensation expense for our equity-based compensation plan introduced during the year ended December 31, 2021 and integration costs related to the Devon Barnett Acquisition incurred during the year ended December 31, 2021, after the conclusion of our transition services agreement with Devon Energy.

Other income and expenses

Gain (loss) on contingent consideration liabilities. We recognized a loss on contingent consideration liabilities of $195.0 million for the year ended December 31, 2021, which was a change of $202.1 million from the $7.1 million gain for the year ended December 31, 2020. This fluctuation was due to the increases in forward curve commodity pricing for natural gas (NYMEX) and oil (WTI) assumptions used in the Monte Carlo simulations increasing the fair market value as of December 31, 2021 as compared to December 31, 2020. The increase in the liabilities is reflected as gain (loss) on contingent consideration liabilities on the consolidated statements of operations. These contingent consideration liabilities were incurred pursuant to the terms of an earnout provision under the Devon Barnett Acquisition purchase agreement.

Interest expense, related party. Interest expense was $2.1 million for the year ended December 31, 2021, which was an increase of $0.4 million from $1.7 million compared to the same period in 2020. The change in related party interest expense during 2021 compared to 2020 was due to the outstanding balances on our loans with BNAC during the year ended December 31, 2021 exceeding the outstanding balances as of December 31, 2020.

Income tax benefit (expense). Income tax benefit was $40.5 million for the year ended December 31, 2021, which was a change of $79.5 million from an income tax expense of $39.0 million compared to the same period in 2020. The year-over-year change was due primarily to the recording of deferred tax assets created by the increase in our commodity derivative liabilities and contingent consideration liabilities during the year ended December 31, 2021.

Earnings from equity affiliates. Earnings from equity affiliates was $0.9 million for the year ended December 31, 2021, which was an increase from zero for the year ended December 31, 2020. Earnings from equity affiliates is related to the management fees received from the BKV-BPP Power Joint Venture and represents the entire increase from the prior year, as we entered into the BKV-BPP Power Joint Venture in 2021.

Liquidity and Capital Resources

Liquidity

In early 2023, natural gas prices began decreasing significantly from previous periods, which if sustained will cause non-compliance of the Company's fixed charge coverage ratio financial covenant beginning with the quarter ending June 30, 2023 and subsequent quarters, and its net leverage ratio financial covenant for the quarter ending December 31, 2023, which covenants are discussed in "*Note 4 — Debt*" and "*Note 15 — Credit and Other Risk*" in the Company's audited consolidated financial statements included elsewhere in this prospectus. Non-compliance with financial debt covenants will limit the Company's ability to draw on its existing credit facilities and could also result in our debt agreements being called early, which would move certain non-current financial obligations to current. As a result, the Company would have insufficient liquidity and capital resources to be able to repay those obligations. Additionally, the Company's reduced cash flow from operations could cause the Company not to meet its current and non-current financial obligations based on our current forecasts. To alleviate these conditions, the Company's ultimate parent, Banpu, has agreed to provide funding to allow the Company to meet its financial obligations until June 30, 2024, if necessary. The Company is also seeking waivers or amendments from lenders for certain debt covenants within the Term Loan Credit Agreement and Revolving Credit Agreement through several quarters into 2024, and is also seeking increased availability for borrowings under the Company's existing credit facilities.

Capital Commitments

Our primary needs for cash are to fund our upstream development, midstream, power and CCUS projects, fund operations and capital expenditures, fund acquisitions, fund asset retirement obligations, cover any debt interest or minimum volume commitment obligations, paydown debt, and return capital to stockholders. Our primary uses of cash during 2022, 2021 and 2020 were to fund our Exxon Barnett Acquisition and Devon Barnett Acquisition, invest in the BKV-BPP Power Joint Venture and fund the development of our natural gas properties. We also used operating cash flows to pay a special dividend to our common stockholders and for operating costs and general and administrative costs. The primary use of the cash received from BNAC was to fund the redemption of our outstanding preferred stock.

During the years ended December 31, 2022, 2021 and 2020, capital expenditures for development of natural gas properties were $235.4 million, $63.9 million and $9.3 million. Capital expenditures for our operated properties are 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 prices for natural gas and NGLs, the availability of equipment, 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 interest owners. We will continue to monitor commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions.

In early 2023, natural gas commodity prices decreased significantly, and we expect this lower natural gas commodity pricing environment to continue at least into the second quarter of 2023. Due to our desire to be a prudent operator and exercise capital discipline in this pricing environment, in March 2023, we decreased our capital expenditures budget for development of natural gas properties for 2023 to $81.0 million from our original budget of $278.0 million, which was the amount applied in connection with the preparation of the estimates of our reserves as of December 31, 2022. We estimate that this reduction in 2023 capital expenditures would result in a decrease in our proved reserves, standardized measure value of proved reserves and the PV-10 value of proved reserves, as of December 31, 2022, by approximately 4.1%, 3.8% and 3.9%, respectively. If the current lower natural gas commodity pricing environment extends beyond 2023, we will continue to maintain capital discipline and reflect corresponding capital expenditure changes in our estimated reserves as of December 31, 2023. These changes would mainly impact proved undeveloped reserves and proved developed non-producing reserves, which collectively represent approximately 27.9% of our total estimated proved reserves as of December 31, 2022.

Our operating leases consist of leases for office space and compressors. We do not have any finance leases. Leases with an initial term of 12 months or less are not recorded on the balance sheet. Instead, the short-term leases are recognized in expenses on a straight-line basis over the lease term. Most leases include one or more options to renew, with renewal terms generally being one year, which are not recognized as part of the ROU assets or lease liabilities on the consolidated balance sheets as they are not reasonably certain to be exercised. The exercise of lease renewal options is at our discretion. As of December 31, 2022, our undiscounted minimum cash payment obligations for operating lease liabilities were $6.0 million through 2026.

Capital Resources

Historically, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations and loans with our majority stockholder, BNAC. We also enter into derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty and stability to our cash flows. We currently believe that we will be able to fully fund our 2023 capital budget, excluding our CCUS capital budget, with cash on hand and cash flows from operations. We expect to fund our CCUS business with a combination of cash flows from operations and funding from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants. The following table summarizes our cash flows for the years ended December 31, 2022, 2021 and 2020 (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Net cash provided by (used in) operating activities	$ 349,194	$ 358,133	$ (7,405)
Net cash (used in) investing activities	(865,566)	(161,858)	(513,992)
Net cash provided by (used in) financing activities	534,833	(79,053)	442,723
Net increase (decrease) in cash and cash equivalents	$ 18,461	$ 117,222	$ (78,674)

Cash flows provided by (used in) operating activities. Net cash provided by operating activities was $349.2 million for the year ended December 31, 2022, compared to $358.1 million of net cash provided by operating activities for the year ended December 31, 2021. Net cash provided by operating activities decreased in 2022 primarily due to our net income position in 2022 versus our net loss in 2021, offset by cash paid for contingent consideration, current year gain on bargain purchase, changes in the fair value of derivatives, and an increase in cash utilized for working capital.

Net cash provided by operating activities was $358.1 million for the year ended December 31, 2021, compared to $7.4 million of net cash used in operating activities for the year ended December 31, 2020. Net cash provided by operating activities increased in 2021 primarily due to increases in natural gas and NGL volumes produced, increases in commodity prices, both before and after the effects of settled commodity derivatives, and decreased cash utilized for working capital.

Operating cash flow fluctuations are substantially driven by realized commodity prices, production volumes and operating expenses. Prices for natural gas and NGLs have historically been volatile, primarily as a result of supply and demand, pipeline infrastructure constraints, basis differentials, inventory storage levels and seasonal influences. We are unable to predict future commodity prices and therefore cannot provide assurance about future levels of cash provided by operating activities.

Cash flows used in investing activities. Net cash used in investing activities increased from $161.9 million for the year ended December 31, 2021 to $865.6 million for the year ended December 31, 2022. Driving this increase is $619.4 million from our acquisition of certain operated and non-operated interests in proved reserves and certain midstream support assets in the Exxon Barnett Acquisition. Approximately $235.4 million of our cash outflows for the year ended December 31, 2022 is from our expenditures in development of natural gas properties. The remainder of the cash outflow is attributable to other investing activities.

Contributing to the $161.9 million cash outflow in 2021 was our initial investment in BKV-BPP Power. In November 2021, BKV-BPP Power purchased an operational power plant in Texas for $88.4 million. The remaining activity in 2021 included $63.9 million attributable to development activities and $7.6 million for developed property and undeveloped acreage acquisition. Development activities have and are anticipated to continue to be funded through cash flows from operations.

Net cash used in investing activities for the year ended December 31, 2020 of $514.0 million primarily consisted of consideration paid for the Devon Barnett Acquisition.

Cash flows provided by (used in) financing activities. Net cash provided by financing activities changed from a $79.1 million outflow for the year ended December 31, 2021 to a $534.8 million inflow for the year ended December 31, 2022. The primary driver of the current period inflow is the $570.0 million of borrowings against the Term Loan Credit Agreement dated June 16, 2022. We also received $75.0 million of proceeds in connection with a related party note payable, offset by $166.0 million of repayments to the related party, and $190.0 million of advances received from our credit facilities, offset by $100.0 million of repayments on these credit facilities. The remainder of the fluctuation consists primarily of contingent consideration settlements, debt issuance cost and deferred offering cost payments, and net share settlements.

Contributing to the net cash used in financing activities of $79.1 million for the year ended December 31, 2021 were exercises of our redemption option on all outstanding shares of preferred stock and the associated shares of common stock for $122.4 million, and dividend payments made to common stockholders and preferred stockholders of $88.1 million and $10.3 million, respectively. We also repaid $24.0 million of our intercompany loan agreements with BNAC, which was offset by $166.0 million of proceeds received under the new loan agreements with BNAC.

Net cash provided by financing activities for the year ended December 31, 2020 of $442.7 million was primarily due to the proceeds from the issuance of common stock, preferred stock and other equity contributions totaling $418.7 million. The remainder was from the proceeds received, net payments made, on the notes payable from BNAC of $24.0 million.

Working Capital

As of December 31, 2022, we had cash and cash equivalents of $153.1 million, compared to $134.7 million of cash and cash equivalents as of December 31, 2021. Our net working capital deficit was $276.5 million as of December 31, 2022, compared to a deficit of $269.0 million as of December 31, 2021.

Our working capital fluctuates based on the timing of cash collections on accounts receivable and payments on accounts payable. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. As of December 31, 2022, we had a working capital deficit of $276.5 million, primarily driven by the $204.0 million current portion of our debt instruments, derivative monetizations payable of $57.0 million and $65.0 million of contingent consideration payable. Excluding debt issuance costs, the $204.0 million current portion of our debt consists of $114.0 million from our Term Loan Credit Agreement and $45.0 million and $45.0 million from our OCBC Credit Facility and Revolving Credit Agreement, respectively, as described below under "*— Loan Agreements and Credit Facilities*." The amounts outstanding under both the OCBC Credit Facility and the Revolving Credit Agreement were due and paid in the first quarter of 2023, and the current portion of our Term Loan Credit Agreement is due in June 2023. The payment relating to the contingent consideration was paid in January 2023. We made such payments on the OCBC Credit Facility, the Revolving Credit Agreement and contingent consideration with our cash flows from operations, and plan to fund the upcoming payment on our Term Loan Credit Agreement with cash flows from operations.

Due to the fluctuation in natural gas prices, our derivative positions, outstanding loans to BNAC and our business being capital intensive, we may incur working capital deficits in the future. We currently believe our cash flows from operations, cash on hand and borrowings under our Revolving Credit Facilities and Revolving Credit Agreement will provide sufficient liquidity to fund our operations and our 2023 capital expenditure budget, excluding our CCUS business, and interest expense and debt repayments that are expected to settle during the next 12 months; however, sustained decreases in natural gas prices may limit our ability to do so.

We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Loan Agreements and Credit Facilities

Intercompany Loan Agreements

On December 17, 2019, BKV O&G entered into a Loan Agreement (the "$10 Million Loan Agreement") with BNAC, a related party, which allowed for a single drawdown in the amount of $10.0 million. On June 23, 2020, we entered into a novation agreement with BKV O&G and BNAC, which transferred all of BKV O&G's rights and obligations under the $10 Million Loan Agreement to us. Also on June 23, 2020, we entered into a First Amendment to the Loan Agreement (the "First Amendment to $10 Million Loan Agreement"). On July 1, 2020, we borrowed $10.0 million thereunder for working capital purposes. The First Amendment to $10 Million Loan Agreement bore interest at a rate calculated monthly based on the outstanding principal balance as of the first of the month at the rate no less than the cost of funding of BNAC. Interest was payable on a monthly basis. During the year ended December 31, 2020, we paid $0.2 million in interest on the loan, and on December 31, 2020, we repaid $5.0 million of the outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.1 million in interest on the loan and repaid the remaining outstanding principal amount of the loan in full. The First Amendment to $10 Million Loan Agreement terminated on June 20, 2021.

On September 28, 2020, we borrowed $119.0 million under a Loan Agreement (the “$119 Million Loan Agreement”) with BNAC to partially fund the Devon Barnett Acquisition and for working capital. The $119 Million Loan Agreement bore interest at six-month LIBOR plus 5.25% per annum and was payable on a semi-annual basis. During the year ended December 31, 2020, we paid $1.5 million in interest on the loan, and on December 16, 2020, we repaid $100.0 million of the original outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.2 million in interest on the loan, and on March 15, 2021. we repaid the remaining outstanding principal amount of the loan in full. The $119 Million Loan Agreement terminated concurrently with repayment of the remaining principal amount.

On November 8, 2021, we borrowed $50.0 million under a Loan Agreement (the “$50 Million Loan Agreement”) with BNAC. On January 11, 2022, we repaid $15.0 million of the outstanding principal amount of the loan. On June 1, 2022, we paid $1.3 million in interest on the loan and repaid the remaining $35.0 million of the outstanding principal amount of the loan in full. The $50 Million Loan Agreement terminated concurrently with the repayment of the remaining principal amount.

Subordinated Intercompany Loan Agreements

On October 14, 2021, we borrowed $116.0 million under a Loan Agreement (the “$116 Million Loan Agreement”) with BNAC to redeem all of the outstanding preferred and common stock of the company owned by OCM BKV Holdings, LLC, an affiliate of Oaktree Capital Management L.P. Following such redemption, we do not have any issued and outstanding preferred stock. As of December 31, 2021, the full $116.0 million balance of the loan remained outstanding. On June 15, 2022, we entered into an Amended and Restated Loan Agreement (the “$116 Million A&R Loan Agreement”), which amended and restated the $116 Million Loan Agreement to, among other things, subordinate the $116.0 million term loan owed to BNAC thereunder to the term loans we borrowed under the Term Loan Credit Agreement. On August 24, 2022, BNAC entered into a Subordination Agreement with Bangkok Bank Public Company Limited, New York Branch, which subordinated the $116.0 million term loan owed to BNAC to the revolving loans at any time outstanding under the Revolving Credit Agreement (the “August 2022 Subordination Agreement”). On September 16, 2022, we repaid the full $116.0 million balance of the loan.

On March 10, 2022, we borrowed $75.0 million under a Loan Agreement (the “$75 Million Loan Agreement”) with BNAC to fund the deposit for the Exxon Barnett Acquisition. On June 15, 2022, we entered into an Amended and Restated Loan Agreement (the “$75 Million A&R Loan Agreement” and, together with the $116 Million A&R Loan Agreement, the “Subordinated Intercompany Loan Agreements”), which amended and restated the $75 Million Loan Agreement to, among other things, subordinate the $75.0 million term loan owed to BNAC thereunder to the term loans under the Term Loan Credit Agreement. The $75 Million A&R Loan Agreement provides for the subordination of the $75.0 million term loan owed to BNAC thereunder to the revolving loans at any time outstanding under the Revolving Credit Agreement. We intend to use a portion of the net proceeds from this offering to repay in full the $75 Million A&R Loan Agreement.

Our payment obligation under the $75 Million A&R Loan Agreement is unsecured and subordinated to our payment obligations under the Term Loan Credit Agreement and the Revolving Credit Agreement, both as discussed further below. The $75 Million A&R Loan Agreement bears interest at SOFR plus 5.25%, is payable semi-annually, and is due on December 31, 2027, including any unpaid interest, unless such payment is prohibited by the subordination terms of the Term Loan Credit Agreement. Subject to such subordination provisions, we are permitted to prepay the $75 Million A&R Loan Agreement at any time, with no prepayment premium.

The $75 Million A&R Loan Agreement includes covenants that, among other things, prohibit us or any of our subsidiaries from merging, incurring liens or incurring any additional indebtedness or guarantees without consent from the lender. The $75 Million A&R Loan Agreement includes financial covenants that require us to:
(1) maintain a net worth (as defined in the $75 Million A&R Loan Agreement, but generally meaning total assets minus total liabilities) of at least $800.0 million at all times; and (2) not permit our trailing twelve month net borrowings to EBITDAX (as defined in the $75 Million A&R Loan Agreement,

but generally meaning the ratio of debt (minus cash) to earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses) ratio to exceed 3.0 to 1.0 at any time. We are in compliance with all associated covenants under the $75 Million A&R Loan Agreement as of December 31, 2022.

Term Loan Credit Agreement

On June 16, 2022, we entered into a Credit Agreement (as amended by that certain First Amendment to Credit Agreement dated as of November 11, 2022, the "Term Loan Credit Agreement") with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent. The Term Loan Credit Agreement includes $600.0 million of commitments for term loans used solely to fund a portion of the purchase price for the Exxon Barnett Acquisition. On June 30, 2022, we borrowed $570.0 million of term loans under the Term Loan Credit Agreement to partially fund the Exxon Barnett Acquisition. Interest is payable semi-annually in June and December using SOFR plus a credit spread adjustment of 0.10% and an interest rate margin of 4.75% per annum. Interest is payable on the last day of each interest period and at maturity. We are obligated to pay certain fees to the lenders and administrative agent under the Term Loan Credit Agreement, including commitment fees, until the term loans are funded or the commitments are terminated.

The term loans mature five years after their initial incurrence and require the prepayment of 20% of their original principal amount on each anniversary of their initial incurrence. Mandatory prepayments are required for casualty losses and asset dispositions in amounts equal to the net proceeds we receive in connection with such casualty loss or asset disposition above an aggregate $25.0 million during the term of the facility. In addition, we are required to prepay the term loans with any cash proceeds we receive from Banpu to cure a financial covenant default. The term loans are subject to a prepayment premium of 2.0% for optional prepayments, mandatory prepayments due to asset dispositions, and certain other mandatory prepayments.

The term loans were funded upon the closing of the Exxon Barnett Acquisition and satisfaction of other customary conditions. The obligations under the Term Loan Credit Agreement are unsecured and guaranteed on an unsecured basis by all of our current and future subsidiaries.

In addition to customary reporting requirements for similarly situated companies, we are required to provide to the administrative agent, and receive its approval of, our annual budget and, commencing with the quarter ending March 31, 2023, each quarterly cash forecast for the succeeding 12-month period.

The Term Loan Credit Agreement contains various restrictive covenants that, among other things, limit our ability and the ability of our subsidiaries to: (i) incur indebtedness (with an exception allowing us to incur, subject to certain limitations and after this initial public offering, up to $200.0 million of unsecured debt for working capital purposes); (ii) incur liens; (iii) acquire or merge with any other company; (iv) sell assets or equity interests of our subsidiaries; (v) make investments (other than direct investments in oil and gas properties and other assets in permitted lines of business); (vi) pay dividends or make other restricted payments (see "*Dividend Policy*" and the next paragraph for further information regarding the permitted dividends under the Term Loan Credit Agreement); (vii) change our lines of business; (viii) enter into speculative hedge agreements; (ix) enter into transactions with affiliates; (x) own any subsidiary that is not organized in the United States; (xi) prepay any debt under the Subordinated Intercompany Loan Agreements; (xii) engage in certain marketing activities; and (xiii) allow, on a net basis, gas imbalances, take-or-pay or other prepayments with respect to our proved oil and gas properties.

The Term Loan Credit Agreement permits us to pay quarterly dividends to our stockholders if, among other things, (i) we have earned sufficient free cash flow (as defined in the Term Loan Credit Agreement), (ii) our pro forma available cash is greater than $100.0 million, and (iii) our adjusted stockholders' equity (as defined generally to mean our stockholders' equity as determined in accordance with GAAP as determined in the most recently delivered financial statements, adjusted to exclude certain unrealized earnout obligations and unrealized gains or losses resulting from hedging agreements and the application of the applicable accounting standard for the hedging instruments) is not less than $800.0 million.

Beginning with the fiscal quarter ending June 30, 2023, the Term Loan Credit Agreement will require us to always hedge not less than 50% of projected production from our proved developed producing reserves for the following 12 months and not less than 25% of the projected production from our proved developed producing reserves for the period beginning 13 months after the measurement date and ending 24 months after such date.

The Term Loan Credit Agreement also includes financial covenants that require us to maintain:

- on a semi-annual basis, a minimum asset coverage ratio (as defined in the Term Loan Credit Agreement, but generally meaning the ratio of the PV-10 value of our proved oil and gas properties to our funded debt) of 2.00 to 1.00;
- on a quarterly basis, a maximum net leverage ratio (as defined in the Term Loan Credit Agreement, but generally meaning the ratio of total funded debt, minus available cash of up to $100.0 million, to our earnings before interest, taxes, depreciation, depletion and amortization) of 2.50 to 1.00; and
- on a quarterly basis, a minimum fixed charge coverage ratio (as defined in the Term Loan Credit Agreement, but generally meaning the ratio of our earnings before interest, taxes, depreciation, depletion and amortization to certain fixed charges) of 1.30 to 1.00.

The Term Loan Credit Agreement includes customary equity cure rights that will enable us, in Banpu's sole discretion, to cure certain breaches of the maximum net leverage ratio covenant or the minimum fixed charge coverage ratio covenant.

The Term Loan Credit Agreement generally includes customary events of default for a syndicated credit facility, some of which allow for an opportunity to cure. In addition, the Term Loan Credit Agreement includes an event of default if there is a material adverse change in our business. If, after this initial public offering, Banpu and its wholly owned subsidiaries cease to own at least 51% of our equity interests, or if any such holder allows any lien to exist on our equity interests that they own, such event will be an event of default under the Term Loan Credit Agreement. If an event of default relating to bankruptcy or other insolvency events occurs, the term loans will immediately become due and payable; if any other event of default exists, the administrative agent or the requisite lenders will be permitted to accelerate the maturity of the term loans.

Revolving Credit Facilities

We are party to a $55.0 million uncommitted credit facility with Oversea-Chinese Banking Corporation Limited, which includes a $25.0 million sublimit for the issuance of standby letters of credit. (the "OCBC Credit Facility"). As of April 13, 2023, $35.0 million in aggregate principal amount was outstanding under the OCBC Credit Facility. We are also party to a $50.0 million uncommitted credit facility with Standard Chartered Bank, which includes a $35.0 million sublimit for revolving loans (the "SCB Credit Facility" and, together with the OCBC Credit Facility, the "Revolving Credit Facilities"). On February 7, 2023, we increased the limit of the SCB Credit Facility from $25.0 million to $50.0 million, which includes a $35.0 million sublimit for revolving loans. The full $50.0 million is available for letters of credit in the absence of cash draw downs. As of April 13, 2023, we had letters of credit for $17.4 million and cash draw downs of $15.0 million outstanding under the SCB Credit Facility. Of the $17.9 million of letters of credit, $3.5 million was issued on behalf of BKV-BPP Retail. We use the Revolving Credit Facilities for letters of credit and working capital purposes.

Revolving Credit Agreement

On August 24, 2022, we entered into the Revolving Credit Agreement with Bangkok Bank Public Company Limited (New York Branch), as the administrative agent and sole initial lender, and on November 11, 2022, we entered into the First Amendment to Revolving Credit Agreement. The Revolving Credit Agreement includes $100.0 million of commitments for unsecured revolving loans used for short-term working capital and operating needs. As of April 13, 2023, no amount was outstanding under the Revolving Credit Agreement.

The revolving loans may be borrowed, repaid and reborrowed during the term of the Revolving Credit Agreement. The Revolving Credit Agreement will mature on September 30, 2027. Mandatory prepayments are required at any time the principal amount of outstanding revolving loans exceeds our receivables from the sales of hydrocarbons produced from our oil and gas properties. In addition, we are required to prepay the revolving loans with any cash proceeds we receive from Banpu to cure a financial covenant default to the extent such cash proceeds are in excess of the amount required to be prepaid under the Term Loan Credit Agreement.

The obligations under the Revolving Credit Agreement are unsecured and guaranteed on an unsecured basis by all of our current and future subsidiaries. Loans under the Revolving Credit Agreement bear interest at one, three or six-month term SOFR plus a credit spread adjustment of 0.10%, plus 4.75% per annum. Interest is payable on the last day of each interest period and at maturity. We are obligated to pay certain fees to the lenders and administrative agent under the Revolving Credit Agreement, including commitment fees on the average daily amount of the undrawn portion of the commitments.

Availability of the revolving loans is limited in amount and conditioned upon the administrative agent's and lenders' receipt and satisfaction with certain deliverables, including, among other things,

- receipt by the Administrative Agent of a certificate from us (i) certifying that the amounts owing to the applicable Payees (as such term is defined in the Revolving Credit Agreement, but generally, the payees of obligations incurred by us) have been paid to the respective Payees prior to the date of such borrowing, (ii) certifying and providing calculations that the requested borrowing does not exceed 110% of the sum of (x) amounts owed to such Payees and (y) Specified Royalty Payments (defined as royalty payments to be made by us or any of our subsidiaries to Payees after the date of such proposed borrowing but on or prior to the last day of the month in which such proposed borrowing occurs) and (iii) certifying that we will pay to the applicable Payees any Specified Royalty Payments prior to the last day of the month in which such borrowing occurs;
- receipt by the Administrative Agent of all documents and/or invoices to be paid by us from the requested borrowing in an amount equal to at least 90% of the requested borrowing; and
- receipt by the Administrative Agent of a certificate from us certifying (i) as to the estimated receivables from the sales of hydrocarbons from our oil and gas properties on the date of such borrowing and (ii) that the amount of item (i) exceeds the sum of the principal amount of all outstanding revolving loans and the aggregate principal amount of the requested borrowing.

In addition to customary reporting requirements for similarly situated companies, we are required to provide to the administrative agent not later than thirty (30) days prior to the end of each fiscal year, a copy of a cash flow projection for each month in the following fiscal year and not later than 20 days after the end of each month, a summary of actual cash flow for such month.

The Revolving Credit Agreement contains various restrictive covenants that, among other things, limit our ability and the ability of our subsidiaries to: incur indebtedness (with an exception allowing us to incur, subject to certain limitations and after this initial public offering, up to $200.0 million of unsecured debt (including amounts under the Revolving Credit Agreement) for working capital purposes); incur liens; acquire or merge with any other company; sell assets or equity interests of our subsidiaries; make investments (other than investments in oil and gas properties and other assets in permitted lines of business); pay dividends or make other restricted payments (see "*Dividend Policy*" and the next paragraph for further information regarding the permitted dividends under the Revolving Credit Agreement); change our lines of business; enter into speculative hedge agreements; enter into transactions with affiliates; own any subsidiary that is not organized in the United States; prepay any debt under the Subordinated Intercompany Loan Agreements; engage in certain marketing activities; and allow, on a net basis, gas imbalances, take-or-pay or other prepayments with respect to our proved oil and gas properties.

The Revolving Credit Agreement permits us to pay quarterly dividends to our stockholders if, among other things, (i) we have earned sufficient free cash flow (as defined in the Revolving Credit Agreement), (ii) our pro forma available cash is greater than $100.0 million and (iii) our adjusted stockholders' equity (as defined generally to mean our stockholders' equity as determined in accordance with GAAP as determined in the most recently delivered financial statements, adjusted to exclude certain unrealized earnout obligations and unrealized gains or losses resulting from hedging agreements and the application of the applicable accounting standard for the hedging instruments) is not less than $800.0 million.

Beginning with the fiscal quarter ending June 30, 2023, the Revolving Credit Agreement will require us to always hedge not less than 50% of projected production from our proved developed producing reserves for the following 12 months and not less than 25% of the projected production from our proved developed producing reserves for the period beginning 13 months after the measurement date and ending 24 months after such date.

The Revolving Credit Agreement also includes financial covenants that require us to maintain:

- on a semi-annual basis, a minimum asset coverage ratio (as defined in the Revolving Credit Agreement, but generally meaning the ratio of the PV-10 value of our proved oil and gas properties to our funded debt) of 2.00 to 1.00;
- on a quarterly basis, a maximum net leverage ratio (as defined in the Revolving Credit Agreement, but generally meaning the ratio of total funded debt, minus available cash of up to $100.0 million, to our earnings before interest, taxes, depreciation, depletion and amortization) of 2.50 to 1.00; and
- on a quarterly basis, a minimum fixed charge coverage ratio (as defined in the Revolving Credit Agreement, but generally meaning the ratio of our earnings before interest, taxes, depreciation, depletion and amortization to certain fixed charges) of 1.30 to 1.00.

The Revolving Credit Agreement includes customary equity cure rights that will enable us, in Banpu's sole discretion, to cure certain breaches of the maximum net leverage ratio covenant or the minimum fixed charge coverage ratio covenant.

The Revolving Credit Agreement generally includes customary events of default for a syndicated credit facility, some of which allow for an opportunity to cure. In addition, the Revolving Credit Agreement includes an event of default if there is a material adverse change in our business. If, after this initial public offering, Banpu and its wholly owned subsidiaries cease to own at least 51% of our equity interests, or if any such holder allows any lien to exist on our equity interests that they own, such event will be an event of default under the Revolving Credit Agreement. If an event of default relating to bankruptcy or other insolvency events occurs, the revolving loans will immediately become due and payable; if any other event of default exists, the administrative agent or the requisite lenders will be permitted to accelerate the maturity of the revolving loans.

BKV-BPP Power Joint Venture

Under the terms of the Limited Liability Agreement of BKV-BPP Power, we do not have the ability to unilaterally cause BKV-BPP Power to make distributions. As of December 31, 2022 and 2021, no distributions have been made by BKV-BPP Power. In addition, we may be required to make additional capital contributions to fund items approved in the annual budget or other matters approved by the board of BKV-BPP Power. Such additional capital contributions, which are not subject to any limit on the potential amount required, would reduce the amount of cash otherwise available for dividend payments by us on our common stock or require us to incur additional indebtedness. However, any additional capital contributions must be approved by a majority of BKV-BPP Power's eight member board of directors, four of which are appointed by us and four of which are appointed by BPPUS. See "*Certain Relationships and Related Party Transactions — BKV-BPP Power Joint Venture — BKV-BPP Power Limited Liability Company Agreement*." Also see "*Risk Factors — Risks Related to Our Power Generation Business — We operate our power generation business through a joint venture which we do not control.*"

Internal Controls and Procedures

As an emerging growth company, we are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes-Oxley Act, and therefore are 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, 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 of the Sarbanes-Oxley Act until the year following our first annual report required to be filed with the SEC. 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.

Material Weakness in Internal Control Over Financial Reporting

We identified certain material weaknesses in our internal control over financial reporting during the second quarter of 2022. As of December 31, 2022, those material weaknesses remained un-remediated. A "material weakness" is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. See "*Risk Factors — Risks Related to the Offering and Our Common Stock — We have identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future, or otherwise fail to maintain effective internal controls over financial reporting, which could result in a restatement of our financial statements or cause us to fail to meet our reporting obligations.*"

We did not design and maintain effective controls to communicate relevant information among departments to completely and accurately record and disclose transactions in the financial statements. This material weakness contributed to two additional material weaknesses in our internal controls. We did not design and maintain effective controls related to (i) the accounting for stock awards and common stock with certain put rights, including the value and classification of such arrangements; and (ii) the communication and evaluation of terms and conditions set forth in complex contracts, including certain of our commodity derivative contracts, relevant to our compliance with financial covenants and related disclosures.

Finally, we did not design and maintain effective controls related to the accounting for income taxes, which were not designed at a sufficient level of precision or rigor to prepare and review the tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and disclosures in the consolidated financial statements, which also resulted in a material weakness in our internal control over financial reporting.

The material weaknesses described above resulted in audit adjustments to our 2021 consolidated financial statements to share capital and other mezzanine equity accounts, liquidity disclosures, income tax benefit, income taxes payable to related party and deferred tax assets. Additionally, each of the material weaknesses described above could result in a misstatement of the aforementioned account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

Notwithstanding these material weaknesses, we believe that our consolidated financial statements fairly present, in all material respects, our consolidated financial condition as of December 31, 2022 and 2021, and our consolidated results of operations and cash flows for the years ended December 31, 2022, 2021 and 2020, in conformity with GAAP. We have begun to take steps towards remediating these material weaknesses primarily by designing and implementing additional internal controls, including those related to (i) the communication of relevant information across departments, (ii) the valuation and classification of stock awards and common stock with certain put rights, (iii) the communication and evaluation of terms and conditions included in complex contracts relevant to our compliance with financial covenants and related disclosures, and (iv) the preparation and review of the income tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and income tax disclosures. Although we believe we are addressing the internal control deficiencies that led to the material weaknesses, the measures we have taken, and plan to take, may not be effective.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that could give rise to material off-balance sheet arrangements. As of April 13, 2023, our material off-balance sheet arrangements and transactions include volume commitments of $233.5 million and letters of credit of $19.0 million against our SCB Credit Facility. For further information regarding these arrangements, see "*Note 16 — Commitments* *and Contingencies*” to our audited consolidated financial statements included elsewhere in this prospectus and above under “*— Loan Agreements and Credit Facilities — Revolving Credit Facilities*.”

Critical Accounting Policies and Estimates

Management’s discussion and analysis of our financial condition and results of operations are based upon our historical consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of certain assets, liabilities and related disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following critical accounting policies relate to the more significant estimates and assumptions used in preparing the historical consolidated financial statements.

Accounting for Natural Gas and NGL Reserve Quantities and Standardized Measure of Future Cash Flows

We use the successful efforts method of accounting for natural gas producing activities. Under this method, the costs to acquire mineral interests in natural gas properties, to drill and equip exploratory leases that find proved reserves, and to drill and equip development leases and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized, or suspended, pending determination of whether the wells have proved reserved. If we determine the wells do not have proved reserves, the costs are charged to expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if sufficient reserves have been found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. We reassess the operational viability of our exploratory wells on at least a quarterly basis, which may involve use of significant judgment. If we determine that future appraisal drilling or development activities are unlikely to occur, the associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year.

The processes we use to estimate quantities of proved and unproved developed natural gas, NGL and oil reserves and their values, future production rates, and future development costs are highly complex and requires significant subjectivity and estimation in the evaluation of available geological, engineering and economic data. The accuracy of any reserves estimate is a function of the quality of data available and of engineering and geological interpretation. The data used in developing reserve estimates may change significantly over time as a result of numerous factors, including, but not limited to, evolving production history, additional development activity, and continual reassessment of the viability of production under varying economic conditions. Although we take every reasonable effort to ensure our reserve estimates are representative of our actual reserves — for example, by involving independent reserve engineers in the assessment of the estimates — the subjective decisions and variances in the data available could give rise to revisions that could materially impact the accompanying historical consolidated financial statements.

Impairment of Natural Gas Properties

The evaluation of impairment of proved and unproved natural gas properties is considered a critical accounting policy due to the significant judgment and estimation involved in ascertaining the probability of future events, such as future market values of natural gas, NGLs and oil, future production costs, and future production volumes, as well as fair valuation of the properties in question. Changes in the judgments and estimates used in our evaluation of impairment, including, but not limited to, the expected future cash flows from natural gas reserves on our properties, could result in the cost of our proved and unproved properties not being recoverable and give rise to the need to record an impairment loss. Similarly, in the instance we determine the property is not recoverable, changes in the estimates and assumptions underlying the model used to derive the fair value of the properties in question may impact the output of the model, which could give rise to significant changes in the amount of impairment loss to record.

Revenue Recognition

We generate the majority of our revenues through the production and sale of natural gas and NGLs. The majority of these sales contracts are short-term in duration and the associated revenue is recognized once control of the distinct goods identified in the contract transfers to the customer at the delivery point specified within the contract. Such sales amounts are based on an estimate of when the volumes delivered at estimated prices, as determined by the applicable sales agreement, which is variable based on commodity pricing. We estimate our sales volumes based on company-measured volume readings. Natural gas and NGL sales are adjusted in subsequent periods based on data received from our purchasers, which for natural gas and NGL sales occur within two months of product delivery. Historically, differences between estimated revenue and actual revenue have not been material but have potential to be in the instance our price or volume estimates are inaccurate.

Non-operated and operated midstream revenues are recognized when services are rendered based on quantities transported and measured according to the underlying contracts. We record midstream revenues based on volumes at stated contractual rates. We estimate our non-operated midstream revenue volumes based on third party data with respect to our proportionate share of non-operated volumes and actual gross volumes for operated midstream revenues. Non-operated midstream revenues are adjusted in subsequent periods based on data received from the operator that reflects actual volumes, which is typically within three months.

Derivative Instruments

We enter into commodity derivative instruments to reduce the effect of price volatility on a portion of our future natural gas and NGL production. These activities may prevent us from realizing the full benefits of price increases above the levels of the derivative instruments on a portion of our future natural gas and NGL production. The commodity derivative instruments are measured and recorded at fair value and included in our consolidated balance sheets. Such fair values are calculated based on the market approach, which uses industry standard models, assumptions and inputs. These assumptions and inputs are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors.

We have not designated any of our derivative contracts as fair value or cash flow hedges for accounting purposes and therefore we do not apply hedge accounting to the commodity derivative instruments. Therefore, net unsettled gains and losses on our commodity instruments are recorded based on the changes in the fair values of the derivative instruments and included within derivative gains (losses), net in the consolidated statements of operations in the period of change.

Derivative instruments are with counterparties of high credit quality and are subject to master netting agreements, and accordingly, the risk of nonperformance by the counterparties is low. However, these activities may prevent us from realizing the full benefits of price increases above the levels of the derivative instruments on a portion of our future natural gas and NGL production.

Acquisitions

We account for business combinations in accordance with ASC Topic 805,*Business Combinations.* Pursuant to the guidance, we allocate the aggregate purchase consideration transferred to affect the business combination to the assets acquired and liabilities assumed based on their fair values as of the acquisition date. Any excess or shortage of the purchase price over the fair value of the assets acquired and liabilities assumed is recognized as goodwill or a gain on bargain purchase, respectively. The amount of goodwill or gain on bargain purchase recorded in a business combination can vary significantly depending on the fair value allocated to the assets acquired and liabilities assumed. Further, in many cases, the valuation of these assets and liabilities requires use of various estimates and assumptions and the exercise of significant judgment about future events.

In transactions where substantially all the gross assets acquired are concentrated in a single identifiable asset or group of similar identifiable assets, the acquisition is treated as an asset acquisition rather than a business combination. We account for asset acquisitions using a purchase price allocation through which the total transaction value is determined by aggregating the base purchase price, certain closing adjustments and contingent consideration, if any. The total transaction value is then allocated to the acquired assets on a pro rata basis based on their fair values. This allocation may cause identified assets to be recognized at amounts that are greater than their fair values. However, “non-qualifying” assets, which include financial assets and other current assets, should not be assigned an amount greater than their fair value. The determination of fair values of assets acquired requires us to make estimates and use valuation techniques. The transaction costs associated with asset acquisitions are capitalized as part of the assets acquired.

As part of the acquisitions made, we are also required to pay additional cash considerations, which are based on certain thresholds being met using forecasted monthly Henry Hub prices, WTI prices and the application of Monte Carlo simulations. This contingency, including the settlement, is described further in "*Note 16 — Commitments and Contingencies*" to our audited consolidated financial statements included elsewhere in this prospectus. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions.

Equity-Based Compensation

Pursuant to the BKV Corporation 2021 Long Term Incentive Plan (the "2021 Plan"), time-vested restricted stock units ("TRSUs") and performance-vested restricted stock units ("PRSUs") may be granted to eligible participants. In each of January 2021 and 2022, we made annual grants of TRSUs under the 2021 Plan. The 2021 Plan will be terminated by the board of directors in connection with this offering and no further awards will be made thereunder. We recognize compensation cost related to these equity-based awards in the consolidated financial statements on a straight-line basis based on estimated grant date fair value, as if all four tranches of the TRSUs were granted at once, rather than being granted on an annual basis over four years. Under the 2021 Plan, if a participant's employment is terminated for any reason other than the participant's resignation or, if a participant's employment is terminated due to his or her voluntary resignation and more than 36 months has passed since the participant's first grant of an incentive award under the 2021 Plan, in each case where the Company had not repurchased the participant's shares of common stock acquired under the 2021 Plan, the participant will have the right to elect to sell such shares back to the Company at an amount equal to the fair market value of the shares at the time the election to sell was made. In November 2021, this put right was amended so that it could not be exercised for at least 181 days following the date the participant's award vests and a "Sell Fund Purchase Program" was implemented whereby, if specifically provided for in an award agreement, participants have the ability to tender shares for repurchase by the Company.

The TRSUs we are authorized to grant include service conditions and the PRSUs we are authorized to grant include service conditions, market performance conditions and non-market performance conditions. In January 2021, we anticipated that we would have made four annual grants of TRSUs under the 2021 Plan in each of 2021, 2022, 2023 and 2024, subject to continued employment, the continuation of the 2021 Plan and other factors; however, there was and is no obligation to make any future grants and any such grants would require approval by our board of directors. Although the TRSUs anticipated to be granted in each of 2022, 2023 and 2024 were not actually granted to the participants when their initial TRSU award was granted, for accounting purposes, the grant date fair value of the anticipated (but not yet granted) TRSUs was determined, based on the service condition and utilizing the fair market value of common stock on the date the 2021 TRSUs were granted. The grant date fair value of the PRSUs was determined based on the service conditions, market performance conditions and non-market performance conditions of the award on the grant and utilizing the fair market value of common stock on the grant date and Monte Carlo simulations, as well as probability assessments relative to the satisfaction of non-market performance conditions. In connection with the change to the put right to implement the 181-day holding period after vesting, an additional charge was recognized with respect to both the TRSUs and PRSUs, given that the fair market value of the common stock on the date of modification had increased from the fair market value on the original grant date.

Compensation cost is recognized ratably on a straight-line basis over the applicable service period. Forfeitures are estimated and recognized over the applicable service period and are re-evaluated at the end of each reporting period. We expect to recognize the forfeitures of the 2023 and 2024 anticipated TRSUs in connection with this offering and the subsequent termination of the 2021 Plan.

We believe that our board of directors, with input from management and the support of third-party valuations, has the relevant experience and expertise to determine the fair value of our common stock. Given the absence of a public trading market of our common stock, and in accordance with the American Institute of Certified Public Accountants Practice Aid, Valuation of Privately-Held Company Equity

Securities Issued as Compensation, numerous objective and subjective factors were considered when determining the best estimate of the fair value of our common stock at each grant date. These factors include:

- the lack of marketability of our common stock;
- our operating and financial performance;
- current business conditions and projections;
- hiring of key personnel and the experience of our management;
- the history of the Company;
- the market performance of comparable publicly traded companies; and
- U.S. and global capital market conditions.

In valuing our common stock, the fair value of our business was determined using various valuation methods, including combinations of income and market approaches with input from management. The income approach estimates value based on the expectation of future cash flows that a company will generate. These future cash flows are discounted to their present values using a discount rate that is derived from an analysis of the cost of capital of comparable publicly traded companies in our industry or engaged in similar business operations as of each valuation date and is adjusted to reflect the risks inherent in our cash flows. The market approach estimates value based on a comparison of the subject company to comparable public companies engaged in similar business operations. From the comparable companies, a representative market value multiple is determined and then applied to the subject company's financial forecasts to estimate the value of the subject company.

Application of these approaches and methodologies involves the use of estimates, judgments, and assumptions that are highly complex and subjective, such as those regarding our expected future revenue, expenses, and future cash flows, discount rates, market multiples, the selection of comparable public companies, and the probability of and timing associated with possible future events. Changes in any or all of these estimates and assumptions or the relationships between those assumptions impact our valuations as of each valuation date and may have a material impact on the valuation of our common stock.

Once our stock is publicly traded, the fair value of each share of underlying common stock will be determined based on the closing price as reported on the date of grant on the primary stock exchange on which our common stock is traded.

Impairment of Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the net assets acquired through the Corporatization Event described in "*Note 3 — Acquisitions and Other Related Activity*" to our audited consolidated financial statements included elsewhere in this prospectus. Impairment may occur if the reporting unit's carrying value exceeds its fair value. Goodwill is tested at the reporting unit level, which is at the consolidated level due to BKV having one identifiable operating segment or reporting unit. We perform an impairment test for goodwill at least annually or when events and circumstances indicate the carrying value may not be recoverable. In performing the required impairment tests, we have the option to first assess qualitative factors to determine if it is necessary to perform a quantitative assessment for goodwill impairment. If the qualitative assessment concludes that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying value, a quantitative assessment is performed.

Our quantitative assessment utilizes present value (discounted cash flow) methods to determine the fair value of the reporting units with goodwill. Determining fair value using discounted cash flows requires considerable judgment and is sensitive to changes in underlying assumptions and market factors. Key assumptions relate to revenue growth, projected operating income growth, terminal values and discount rates. If current expectations of future growth rates and margins are not met, or if market factors outside of our control, such as factors impacting the applicable discount rate, or economic or political conditions in key markets change significantly, then goodwill allocated to the reporting unit may be impaired. Management determined there were no circumstances indicating the carrying value may not be recoverable during the years ended December 31, 2022, 2021 and 2020. There have been no impairments recorded related to goodwill as the results of the annual quantitative impairment test indicated the fair value of the assets of the reporting unit to be greater than the carrying value as of December 31, 2022, 2021 and 2020.

Litigation and Environmental Contingencies

In the ordinary course of business, we may at times be subject to claims and legal actions. Management does not believe the impact of such matters will have a material adverse effect on our financial position or results of operations.

We are subject to extensive federal, state, and local environmental laws and regulations, which may materially affect our operations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require us to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

In our acquisition of existing assets, we may not be aware of what environmental safeguards were taken during the time such assets were operated, and it is possible we may acquire certain environmental liabilities along with such assets.

We maintain comprehensive insurance coverage that we believe is adequate to mitigate the risk of any adverse financial effects associated with these risks. However, should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could still fall upon us. No claim has been made, nor are we aware of any liability which we may have, as it relates to any material environmental cleanup, restoration, or the violation of any rules or regulations relating thereto.

Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed as incurred. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the cost can be reasonably estimated.

Recent Accounting Pronouncements

See "*Note 2 — Summary of Significant Accounting Policies*" to our audited consolidated financial statements included elsewhere in this prospectus for more information about recent accounting pronouncements, the timing of their adoption, and our assessment, to the extent we have made one, of their potential impact on our financial condition and our results of operations.

Quantitative and Qualitative Disclosure About Market Risk

Commodity Price Risk and Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas and NGLs production. Pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production. Pricing for natural gas and NGLs has historically been volatile and unpredictable, and we expect this volatility to continue in the future. The prices we receive for our production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flows caused by changes in commodity prices, we enter into financial derivative instruments for a portion of our natural gas and NGLs production when management believes that favorable future prices can be secured.

Our financial hedging activities are intended to support natural gas and NGLs prices at targeted levels and to manage our exposure to natural gas and NGLs price fluctuations. These contracts may include commodity price swaps, whereby we will receive a fixed price and pay a variable market price to the contract counterparty, producer collars that set a floor and ceiling price for the hedged production, enhanced three-way collars that set a floor and ceiling price for the hedged production with the potential for hedged volumes doubling above the ceiling price, or basis differential swaps. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. The derivative contracts outstanding as of December 31, 2022 consisted of commodity price swaps, basis differential swaps and producer collar agreements, subject to master netting agreements with each individual counterparty.

These derivative contracts cover portions of our projected positions through 2024. Our commodity hedge position as of December 31, 2022 is summarized in "*Note 7 — Derivative Instruments*" to our audited consolidated financial statements included elsewhere in this prospectus.

We may enter into hedge contracts with a term greater than 24 months, but for no longer than 36 months, for up to 60% of our estimated production for the current year, and for up to 50% and 25% of our estimated production in each of the subsequent years, respectively. During the year ended December 31, 2022, a hypothetical increase or decrease of $0.10 per Mcf in NYMEX would have resulted in a $7.7 million decrease or increase in natural gas hedge revenues, respectively, and a hypothetical increase or decrease of $1.00 per Bbl of each NGL purity product price would have resulted in a $4.6 million decrease or increase in NGL hedge revenues, respectively.

Additionally, to reduce its exposure to fluctuations in the market price of electricity and natural gas, BKV-BPP Power enters into financially settled HRCOs, which are contracts for the financial purchase and sale of power based on a floating price of natural gas at a predetermined location using a predetermined conversion factor, or heat rate, required to turn the fuel input into electricity. BKV-BPP Power is exposed to basis risk in its operations when its derivative contracts settle financially and it delivers physical electricity on different terms. For example, if BKV-BPP Power enters into an HRCO, it hedges its electricity production based on an agreed price for that electricity, but physical electricity must be delivered to delivery points in the market it serves. BKV-BPP Power is exposed to basis risk between the hub price specified in the HRCO and the price that it receives for the sales of physical electricity. BKV-BPP Power attempts to hedge basis risk where possible, but hedging instruments are sometimes not economically feasible or available in the quantities that it requires. BKV-BPP Power's hedging activities do not provide it with protection for all of its basis risk and could result in economic losses and liabilities, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock. Additionally, by using derivative instruments to economically hedge exposure to changes in power prices, we could limit the benefit we would receive from increases in the power prices, which could have an adverse effect on our financial condition. Moreover, in the event BKV-BPP Power is not able to satisfy its obligations under the HRCO, it must purchase power at prevailing market prices to satisfy the HRCO. Likewise, increases in power pricing could limit the benefit we receive under HRCOs and may result in losses. Either such event could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

All derivative instruments, other than those that meet the normal purchase and normal sale scope exception, are recorded at fair market value in accordance with GAAP and are included in our consolidated balance sheets as assets or liabilities. The fair values of our derivative instruments are adjusted for non-performance risk. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; therefore, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our consolidated statements of operations. We present total gains or losses on commodity derivatives (for both settled derivatives and derivative positions which remain open) within operating revenues as "Derivative gains (losses), net."

Mark-to-market adjustments of derivative instruments cause earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled or monetized prior to settlement. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are only impacted when the associated derivative contracts are settled or monetized by making or receiving payments to or from the counterparty. As of December 31, 2022, the estimated fair value of our commodity derivative instruments was a net liability of $46.0 million, comprised of current assets and liabilities and non-current assets. As of December 31, 2021, the estimated fair value of our commodity derivative instruments was a net liability of $104.8 million, comprised of current assets and current and noncurrent liabilities.

By removing price volatility from a portion of our expected production through December 2024, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

Counterparty Credit Risk

We routinely monitor and manage our exposure to counterparty risk related to derivative contracts by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings, and avoiding concentration of credit exposure by transacting with multiple counterparties. Our commodity derivative contract counterparties are typically financial institutions with investment-grade credit ratings.

We enter into International Swap Dealers Association ("ISDA") Master Agreements with each of our derivative counterparties prior to executing derivative contracts. The terms of the ISDA Master Agreements provide, among other things, the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or counterparty to a derivative contract.

In addition, we utilize an unaffiliated third party to market all of our natural gas production to various purchasers, which consist of credit-worthy counterparties, including utilities, LNG producers, industrial consumers, major corporations and super majors, in our industry. We rely on the credit worthiness of such third party marketer, who collects directly from the purchasers and remits to us the total of all amounts collected on our behalf less their fee for making such sales. See "*Business — Customers and Product Marketing"* and "*Risk Factors — Risks Related to Our Upstream Business and Industry — A substantial percentage of our natural gas and NGL production is gathered, processed and transported by a single third party and all of our natural gas production is marketed by a single third party.*"

Interest Rate Risks

As of December 31, 2022, our primary exposure to interest rate risk results from our outstanding related party borrowings with BNAC, the Term Loan Credit Agreement and the Revolving Credit Facilities, which have floating interest rates. As of December 31, 2022, we had outstanding borrowings with BNAC of $75.0 million, $90.0 million outstanding borrowings on our credit facilities, and an additional $570.0 million outstanding borrowings under the Term Loan Credit Agreement. The average annualized interest rate incurred on our outstanding borrowings during the year ended December 31, 2022 was approximately 6.6%. We estimate that a 1.0% increase in the applicable average interest rates for the year ended December 31, 2022 would have resulted in an increase of $5.7 million in interest expense.

INDUSTRY

We primarily produce natural gas from our owned and operated upstream businesses, which we expect to achieve net zero Scope 1 and Scope 2 emissions by the end of 2025, and net zero Scope 1, 2 and 3 emissions from our owned and operated upstream business by the early 2030s. The company was founded on acquiring and producing natural gas and we have expanded into a total of four business lines: natural gas production, natural gas gathering, processing and transportation, power generation and CCUS. We formally launched our CCUS business, BKV dCarbon Ventures, in March 2022, and then, in June 2022, we reached FID and entered into a definitive agreement with EnLink in connection with our first high concentration CCUS project in the Barnett, which we refer to as the Barnett Zero Project. Subsequently, in October 2022, we reached internal FID on our second CCUS project, which we refer to as the Cotton Cove Project. In addition, we expect to continue to identify and evaluate additional CCUS projects. CCUS projects and the sector generally are in their early stages and continue to evolve since the 2015 Paris Climate Agreement (the "Paris Agreement") drew global commitment to delivering a net-zero emission economy.

Our CCUS business and all of our CCUS projects are in the early stages of development and while we have reached FID and entered into definitive agreements with respect to the Barnett Zero Project and reached internal FID for the Cotton Cove Project, we have not reached FID or entered into definitive agreements necessary to execute any of the other potential projects we have identified in "*Business — Our Operations — Carbon Capture, Utilization and Sequestration*" and may not be able to reach agreements on terms acceptable to us, or to achieve our projected timeline for commercial operations. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. Furthermore, the commercial viability of our CCUS projects depends, in part, on certain financial and tax incentives provided by the U.S. federal government. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business*." In addition, we continue to evaluate the potential expansion of our integrated energy platform into retail power connectivity, while monitoring the potential impact the LNG industry may have on our business.

Carbon Capture, Utilization and Sequestration

CCUS involves the capture of CO_2 emissions and the processing of such emissions for reuse or permanent storage in subsurface geological formations, and is recognized as a primary means of reducing CO_2 emissions from large-scale energy and industry sources.

To advance the objectives outlined in the Paris Agreement, the United States released goals in 2021 that included delivering a net-zero emission economy by no later than 2050 (and 2035 for the electric power sector). According to Global CCS Institute's Global Status of CCS 2021, the global CCUS industry must grow by more than a factor of 100 by the year 2050 to achieve Paris Agreement climate targets, equating to approximately 70 to 100 new facilities per year and achieving long-term emissions reduction targets will require installed CCUS capacity to increase to over 5,600 Mtpa by 2050 and an estimated capital investment of $655 billion to $1.280 trillion by 2050.

According to the Global Status of CCS 2022 Report, as of September 2022, there were 196 projects in the worldwide CCUS facilities pipeline (including two suspended projects). This represents an impressive 44% year over year growth and continues the upward momentum in CCUS projects in development. Additionally, the Global CCS Institute reported that, as of September 2022, 30 CCUS facilities were operational around the world. In Energy Technology Perspectives 2020, published by the International Energy Agency ("IEA"), the IEA estimated that 80% of industrial facilities and power plants accounting for 85% of emissions are located within 100 kilometers of a potential storage site.

To stimulate investment in CCUS, the US Energy Act of 2020 provided over $6 billion for CCUS research and development programs, and in 2021, the U.S. Treasury and the Internal Revenue Service ("IRS") issued critical guidance on Section 45Q tax credits for carbon capture and storage, expanding its applications to a wider range of CCUS activities. In addition, the Inflation Reduction Act of 2022, which was signed into law on August 16, 2022, provides significant incentives for CCUS investment.

The current CCUS industry can be described as highly fragmented with a wide range of technologies and processes being evaluated for long-term viability across the value chain including capture, separation, compression, liquefaction, transportation, storage and utilization. According to the Global Status of CCS 2022 Report, CCUS has become increasingly commercial and competitive in many countries and CCUS networks involving the use of shared transport and storage infrastructure are becoming the predominant method of CCUS deployment, which benefits smaller projects that lack vertical integration.

Power Generation

The United States electricity market starts with utility-scale generators that generate electricity from fossil fuels, nuclear energy and renewable energy. Utility scale plants and other renewable energy sources sell electricity to the wholesale market, including electric utility companies, competitive power providers and electricity marketers, who then sell electricity to retail end-users.

The power industry consists of a variety of companies that are engaged in the generation or distribution of power, with most electric utility companies relying on natural gas to generate a portion of their power. According to the IEA, overall demand for electricity decreased during the initial phases of COVID-19, but has since increased as lockdowns subsided and manufacturing activities re-bounded. According to the IEA, global electricity demand rose by 6% in 2021, 2% in 2022 and is expected to rise by an average of 3% over the next three years.

In the near future, demand for retail electricity is expected to grow modestly, driven by increased consumption from commercial and industrial customers recovering from the pandemic. The United States recorded a significant 2.6% year over year demand increase in 2022, driven by economic activity and higher residential use to meet both heating and cooling needs. Short-term demand for electricity can vary with weather conditions and economic shocks, which increases unpredictability. Because long-term demand depends on economic growth and efficiency improvements, the growth of the national economy directly impacts U.S. power consumption.

The sources for U.S. electricity have increasingly consisted of natural gas and renewable energy sources. While coal and nuclear energy sources have been declining, natural gas and renewable sources have been expanding their share of total electricity generation in the United States. According to the IEA, in 2022, renewables grew to account for the largest share of total utility-scale electricity generating capacity in the United States at 36%, followed by natural gas at 33%. According to the IEA, the share of natural gas-based electricity generation tripled from 12% in 1990 to 36% in 2022. Given the multi-year highs in natural gas procurement pricing and supply chain constraints, capital spending budgets and customer affordability concerns are expected to increase.

Liquified Natural Gas

LNG is natural gas in its liquid phase after being super-cooled to-260°F. LNG is primarily used to store and transport gas between markets that have limited natural gas pipeline connectivity. Once natural gas is delivered to an LNG facility, the gas is liquified and shrunken to approximately 1/600th of its original volume. Then, the LNG is loaded onto carriers that have large cryogenic tanks onboard for oceanic transport. At receiving terminals, the LNG is transitioned back into its original gaseous state. From there, the regassified gas is either stored or transported via pipeline to end-consumers like power plants, industrial facilities, and residential communities.

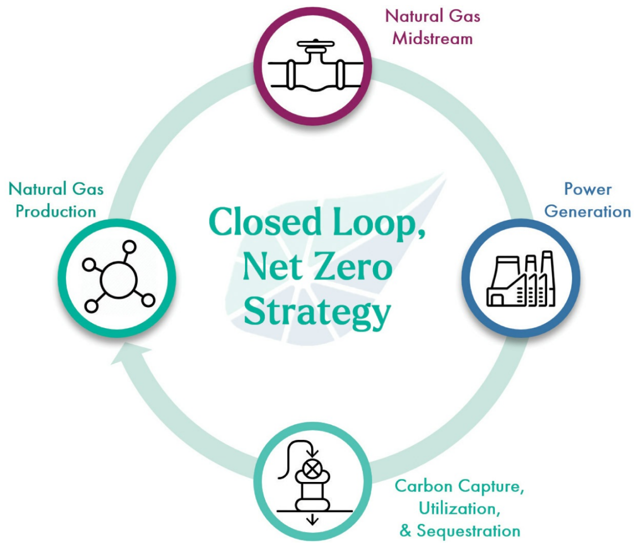
In the wake of the Russian invasion of Ukraine, Russia’s steep gas supply cuts to the EU put pressure on European and global gas markets. According to the EIA, before Russia’s piped natural gas exports to the EU declined by an estimated 49% year-over-year in 2022, close to 40% of total EU gas demand was sourced from Russia. To mitigate that shortfall, European LNG imports increased by 65% compared to 2021, according to the EIA, which also reported that U.S. LNG exports to Europe increased by 141% over the same period, representing 64% of all U.S. LNG exports in 2022. According to the EIA and FERC, because U.S. LNG utilizations are at all-time highs at 98% of baseline capacity, an additional 11.9 Bcf/d capacity is currently under construction, and another 19.1 Bcf/d in capacity has been approved by FERC. Current market dynamics have poised LNG for expansion, particularly in the U.S. Gulf Coast, where approximately 90% of the U.S. LNG build is slated, according to FERC. The Barnett region is approximately 300 miles from the

Gulf Coast LNG market. Producers are capitalizing on these dynamics by entering into supply agreements that provide a take-or-pay style fixed liquefaction fee for the LNG facility and efficient access to the global gas markets. Upstream producers with exposure to international LNG natural gas prices are expected to provide a baseline of pricing support for Texas and Louisiana-based natural gas producers with pipeline connectivity to the Gulf Coast.

BUSINESS

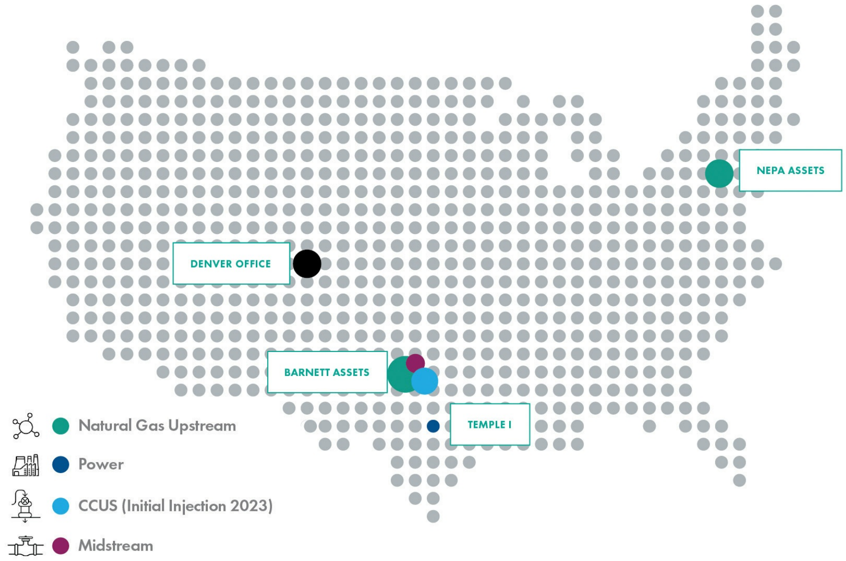
Overview

We are a forward thinking, growth driven energy company focused on creating value for our stockholders through the organic development of our properties as well as accretive acquisitions. Our core business is to produce natural gas from our owned and operated upstream businesses, which we expect to achieve net zero Scope 1 and Scope 2 emissions by the end of 2025, and net zero Scope 1, 2 and 3 emissions from our owned and operated upstream business by the early 2030s. We maintain a “closed-loop” approach to our net zero emissions goal with our four business lines: natural gas production, natural gas gathering, processing and transportation (our “natural gas midstream business”), power generation, and carbon capture, utilization and sequestration (“CCUS”). We are committed to building a vertically integrated business to reduce costs and improve overall commercial optimization of the full value chain. For instance, our natural gas production in the Barnett is gathered and transported through our midstream systems, and we are seeking to establish arrangements to supply our natural gas production directly to the BKV-BPP Power Joint Venture. We believe that our differentiated business model, net zero emissions focus, highly experienced management team and technology-driven approach to operating our business will enable us to create stockholder value.



We understand the impact climate change has on our community, the world and future generations, which is why addressing these impacts in how energy is produced is a top priority. In particular, it is one of our core values, “Be One BKV,” to create a unified team with a shared vision to achieve our emission reduction and energy impact goals.

BKV Assets



Overview of BKV Assets

Natural Gas

	Twelve Months Ending Dec '22 Net Production (MMcfe/d)	Dec '22 SEC 1P Reserves (Tcfe)	Producing Wells[1]	Net Acres
Barnett	733	5.24	6,926	458,000
NEPA	139	0.90	411	37,000
Total	872	6.14	7,337	495,000

Operated Midstream

	As of Dec '22 Throughput (Mmcf/d)	Pipeline Miles	Midstream Compressors
Barnett	220	778	65

Power

	Location	Heat Rate Btu/kWh	Capacity MW+
Temple 1	Bell County, TX	6,950	755

[1] Includes producing wells in which BKV has an ORRI or Non-Operated interest

Our Operations

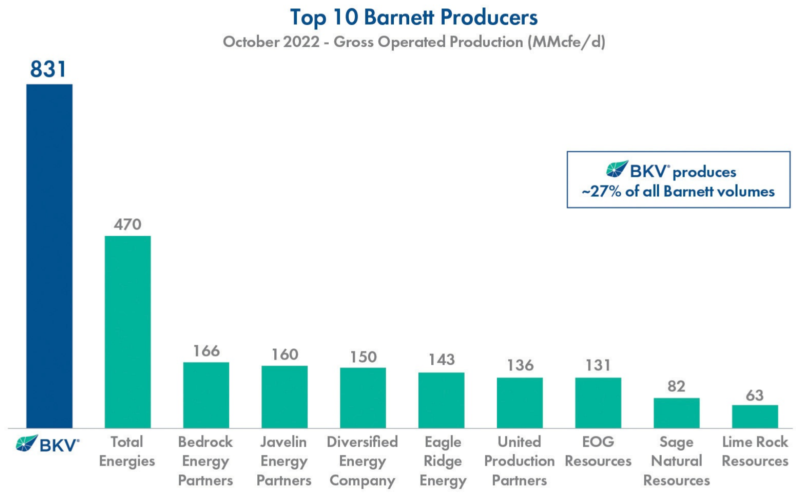
Natural Gas Production

We are engaged in the acquisition, operation and development of natural gas and NGL properties primarily located in the Barnett and in NEPA. Our upstream assets are the core of our business and provide us with substantial Adjusted Free Cash Flow, which we expect will be sufficient to fund our upstream, midstream and power capital expenditure program while maintaining a conservative balance sheet. We have a balanced portfolio of low decline producing properties and undeveloped inventory, primarily in the Barnett. Additionally, our focus on operational efficiencies, access to BKV-owned and third-party midstream systems, and proximity to natural gas demand markets along the Gulf Coast and Northeast corridor allow us to generate high margins.

As of December 31, 2022, our total acreage position was approximately 495,000 net acres, 99% of which was held by production. As of December 31, 2022, our net daily production (after giving effect to the Exxon Barnett Acquisition) averaged 871.9 MMcfe/d, consisting of approximately 79% natural gas and approximately 21% NGLs. As of December 31, 2022, our total proved reserves of 6,136 Bcfe had an estimated 7.3% year-over-year average base decline rate over the next 10 years. We have more than 10 years of core inventory remaining, with attractive returns, based on a 1 to 1.5 rigs per year pace, including 194 proved undeveloped, 162 probable and 137 possible horizontal locations, and 584 proved developed non-producing, 743 probable, and 234 possible refrac candidates. Based on current commodity prices, the capital investment required to hold production flat year-over-year is less than approximately 35% of our Adjusted EBITDAX for the 2022 fiscal year. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See "*Prospectus Summary — Summary Historical and Unaudited Pro Forma Financial Information — Non-GAAP Financial Measures*" for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

We entered the Barnett in October 2020 with our acquisition of the 2020 Barnett Assets from Devon Energy. On June 30, 2022, we further scaled our Barnett position by acquiring approximately 165,000 net acres, 2,100 operated wells and related upstream, midstream and other assets in the Exxon Barnett Acquisition. As of December 31, 2022, our Barnett acreage position was approximately 458,000 net acres, which is approximately 99% held by production. Our average daily Barnett production (after giving effect to the Exxon Barnett Acquisition) of approximately 732.7 MMcfe/d for the year ended December 31, 2022 consisted of 75% natural gas and 25% NGLs. We had an average working interest in our operated wells in the Barnett of approximately 96.2% as of December 31, 2022 and an Effective NRI in the Barnett of approximately 80.25%.

We are the largest natural gas producer by gross operated volume in the Barnett. Based on information published by the TRRC, the chart below illustrates our gross operated production volumes in the Barnett (including the Exxon Barnett Acquisition), which represent approximately 27% of the total Barnett production, and nearly 75% greater than that of the next largest producer in the Barnett for the month of October 2022.



We entered NEPA in 2016 and have subsequently scaled our position through 12 acquisitions. As of December 31, 2022, our acreage position was approximately 37,000 net acres, which is approximately 94% held by production. Our average net daily production of 139.2 MMcfe/d for the year ended December 31, 2022 consisted entirely of natural gas. We had an average working interest in our operated wells in NEPA of 88%, as of December 31, 2022.

Natural Gas Midstream

Through our ownership in midstream systems, we are engaged in the gathering, processing and transportation of natural gas (which we refer to as our natural gas midstream business) that supports our upstream assets and third-party producers in the Barnett and NEPA. Our midstream assets improve our overall corporate returns by enhancing our margins and lowering our break-even operating costs while allowing us to manage the timing, development and optimization of production of our upstream assets. In the Barnett, as of December 31, 2022, approximately 190 MMcf/d of our gross production (approximately 23% of our total gross Barnett production) was gathered and processed by our owned Barnett midstream system, which includes approximately 778 miles of gathering pipeline, 65 midstream compressors and one amine processing unit. Additionally, our owned Barnett midstream system has over 200 MMcf/d in unutilized pipeline and processing capacity, providing room to increase throughput (from our own production and for third-party volumes) while maintaining optimal operating pressure with limited additional capital investment required. We also believe we have ample dedicated capacity on third party midstream systems for our expected production and future development. In NEPA, as of December 31, 2022, we had an approximate 29.4% non-operated ownership interest in a midstream system, which is operated by subsidiaries of Repsol, with throughput of approximately 174 MMcf/d, and we separately own and operate approximately 16 miles of natural gas gathering pipelines, 14 miles of freshwater distribution pipelines and six gas compression units.

Power Generation

We have a 50% ownership interest in the BKV-BPP Power Joint Venture, which owns Temple I, a newly-constructed, modern combined cycle gas and steam turbine power plant located in the Electric Reliability Council of Texas ("ERCOT") North Zone in Temple, Texas. The remaining 50% interest is owned by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu. Temple I has an annual average power generation capacity of 755 MW and delivers power to customers on the ERCOT power network in Texas. Temple I is among the most efficient generators supplying power to ERCOT, with a baseload design heat rate of approximately 6,950 Btu/kWh, which is well below the ERCOT CCGT average. Temple I's modern technology enables it to respond to rapidly changing market signals in real time by minimizing congestion risk and ensuring the highest operational readiness during the time when electricity consumption peaks (in winter and summer), making it well-suited to serve the various needs of the ERCOT market. We expect our power generation assets will be synergistic with our base upstream business. In the near term, we will seek to establish midstream contracts that allow us to supply our own natural gas directly to Temple I and its firm intrastate natural gas storage service at the Bammel storage facility. Supplying our own natural gas to Temple I will reduce gas transportation costs and create reciprocal natural hedges for both businesses via vertical integration. Additionally, we leverage our existing organization to provide marketing, engineering, finance, accounting and other administrative services to the BKV-BPP Power Joint Venture for an annual fee plus expenses.

In addition, after receiving the necessary approvals from the PUCT and ERCOT, the BKV-BPP Power Joint Venture recently launched a retail marketing business to sell electricity to commercial, industrial, and residential retail customers in Texas through its wholly owned subsidiary, BKV-BPP Retail, under the brand name BKV Energy. Moreover, we intend to develop our ability to provide a Scope 1, 2 and 3 carbon neutral gas product, which we refer to as MNZ gas, and we believe that the expansion of our presence in the retail power space, along with the synergistic and opportunistic growth of our upstream, midstream and power generation businesses, will provide our retail energy business the opportunity to offer end consumers household energy sourced from MNZ gas. For more information about the risks involved in our retail power business and efforts to market MNZ gas, see "*Risk Factors — Risks Related to Our Power Generation Business — Our long-term business plan involves the expansion of our retail power business and the development of opportunities to offer end consumers household energy sourced from a Scope 1, 2 and 3 carbon neutral gas product*."

Carbon Capture, Utilization and Sequestration

Through our CCUS business, we aim to reduce man-made GHG emissions to the atmosphere by capturing CO_2 emitted in connection with natural gas activities, whether from our own operations or third-party operations, as well as from other energy and industrial sources. Our process involves capturing CO_2 before it is released into the atmosphere and then compressing the captured CO_2 and transporting it via pipeline to sites where it can be injected into UIC wells for secure geologic sequestration. Additionally, we have engaged Project Canary to measure, analyze and report the environmental attributes of the sequestration projects. Although we formally launched our CCUS business in March 2022 with the establishment of BKV dCarbon Ventures, we have been evaluating project opportunities and developing our CCUS business for approximately two years. The development of our CCUS business has progressed rapidly, supported by internal engineering, business development and regulatory professionals, along with academics and CCUS-focused partnerships. We believe that with a continued and timely execution of our business plans, and the receipt of external funding in 2023, we will begin generating positive CCUS net income via tax credits and other tax benefits in 2025. We expect to fund our CCUS business with a combination of cash flows from operations and funding from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified and described below.

We seek to execute CCUS projects with attractive standalone economics for high, medium and low CO_2 concentration streams that will sequester emissions from both our own operations and from third-party operations. As part of our "closed-loop" approach to our net zero emissions goal, we expect to apply the CO_2 emissions that are sequestered through our CCUS business to offset GHG emissions from our owned and operated upstream businesses. As a result, we expect our CCUS business to contribute to our goals to fully offset the Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025, and the Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s. We estimate that our owned and operated upstream Scope 1 and 2 annual emissions were approximately 1.7 Mtpy CO_2e as of December 31, 2022 and that our owned and operated upstream Scope 1, 2 and 3 annual emissions were approximately 15.32 Mtpy CO_2e as of December 31, 2022. See "— *Path to Net Zero Emissions*" below for a description of how we estimate our Scope 1, 2 and 3 annual emissions and how we expect our CCUS business to contribute to the offset of those emissions.

In August 2022, we entered into a development agreement with Verde CO2, an independent carbon capture and sequestration developer and operator, to identify, evaluate and develop additional CCUS projects throughout the United States. We believe our agreement with Verde CO2 will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration. As of April 6, 2023, we have paid $17.3 million to Verde CO2 under the development agreement. We currently expect to invest up to $250.0 million over the next three years to fund efforts by BKVerde, a subsidiary of BKV dCarbon Ventures, to efficiently identify and evaluate feasible CCUS projects, and to execute on those projects.

Currently, we are pursuing twelve potential CCUS projects that we believe are commercially viable based on economics supported by enhanced Section 45Q tax credits and can be completed by the early 2030s. We anticipate that the completion of these or a combination of other comparable projects would enable us to achieve our Scope 1, 2 and 3 emissions goals. These twelve potential CCUS projects consist of a combination of projects being developed by BKV's internal CCUS team and projects being developed by Verde CO2. Under our development agreement with Verde CO2, Verde CO2 will develop and present projects to us for acceptance and assignment to BKVerde; however, we cannot guarantee that all projects currently in development by Verde CO2 will be accepted and assigned to BKVerde. See "*— Recent Developments — CCUS Project Development with Verde CO2*." Our projected timeline for commercial operations of these twelve projects by the early 2030s depends in part on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. Our timeline also depends on a regulatory environment that is favorable to our projects and their development. These twelve potential projects can be placed into four categories: (i) those that have reached FID, (ii) near-term NGP projects, (iii) near-term industrial projects, and (iv) projects under evaluation. Near-term projects are those that we anticipate will reach FID in either 2023 or 2024. We have achieved notable milestones with respect to several of the projects within the four categories, as more fully described below.

FID Projects

We have reached FID and entered into definitive agreements with respect to the Barnett Zero Project, and we have reached internal FID for the Cotton Cove Project. These two projects have a combined forecasted annual sequestration volume of approximately 255,000 metric tons per year of captured CO_2e by the end of 2024.

Barnett Zero Project. In June 2022, we reached FID and entered into a definitive agreement in connection with our first high concentration CCUS project in the Barnett with EnLink. This CCUS project, which we refer to as the Barnett Zero Project, will separate CO_2 from substantially all of our EnLink-gathered natural gas production. In the Barnett Zero Project, EnLink will transport our natural gas produced in the Barnett to its natural gas processing plant in Bridgeport, Texas, where the CO_2 waste stream will be captured, compressed and then disposed of and sequestered via our nearby injection well. We expect the Barnett Zero Project to achieve an average sequestration rate of up to approximately 210,000 metric tons of CO_2e per year, with the first injection expected by December 2023. Following commencement of commercial operations of our project with EnLink, we intend to use this project as a prototype for modular NGP projects that can be repeated and quickly scaled.

Cotton Cove Project. On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of, and geologically sequester CO_2 generated as a byproduct of our natural gas production in the Barnett and will utilize our newly acquired BKV Midstream assets to do so. We have multiple company-owned pore space opportunities for CO_2 injection, and we estimate the Cotton Cove Project will geologically sequester up to approximately 45,000 metric tons of CO_2e per year. We currently estimate the total investment required by us for the Cotton Cove Project to be between approximately $14.0 and $24.0 million. We are targeting commencement of CO_2 sequestration activities by the first half of 2024, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects.

We are also seeking to expand the Barnett Zero and Cotton Cove Projects to pilot, and then scale, post-combustion carbon capture technology that would allow us to sequester up to an additional approximately 250,000 metric tons per year of captured CO_2e from low concentration emissions from within our BKV

Midstream and/or EnLink's Bridgeport processing operations. As part of this process, we intend to utilize compressor waste heat to reduce energy requirements and cost.

NGP Projects

In addition to the Barnett Zero Project and the Cotton Cove Project, we have identified three potential NGP projects to sequester third-party emissions, which we expect to reach FID in either 2023 or 2024. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of at least approximately 970,000 metric tons per year of captured CO_2e.

A significant portion of the carbon capture infrastructure necessary to execute these potential NGP projects already exists, one of which is currently being developed by Verde CO2 under our development agreement with them. For another one of these projects, we have entered into a non-binding letter of intent to secure a pore space leasehold that would provide approximately 45 million metric tons of CO_2e sequestration capacity. Therefore, if approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2025. We expect that by the end of 2025, these three NGP projects will have initial individual annual sequestration volumes of approximately 70,000, 265,000 and 635,000 metric tons per year of captured CO_2e, respectively, and a combined annual aggregate sequestration volume of approximately 970,000 metric tons per year of captured CO_2e. In addition, we expect over time to submit permit applications to develop Class VI injection wells in order to expand the sequestration capacity of two of these NGP projects to gradually build up to a forecasted annual sequestration volume after 2025 for all three of these NGP projects of approximately 3.3 million metric tons per year of captured CO_2e.

We expect by the end of 2025 that the combined annual forecasted sequestration volume from these NGP projects, the Barnett Zero Project and the Cotton Cove Project (collectively having an annual forecasted sequestration volume of approximately 1.23 Mtpy CO_2e), would be capable of offsetting annually more GHG emissions than our remaining Scope 1 and 2 annual emissions from our owned and operated upstream businesses after taking into account the expected GHG emissions reductions from our "Pad of the Future" program, reductions attributable to emissions monitoring and leak surveys and emissions offsets from the installation of solar power (such remaining emissions estimated to be approximately 0.70 Mtpy CO_2e). See "*— Path to Net Zero Emissions.*" However, we have not secured external financing, reached FID or entered into definitive agreements for any of these three additional NGP projects. We may not complete all or any of these three additional NGP projects, the Barnett Zero Project or the Cotton Cove Project by December 31, 2025, in which case, we may consider alternatives to offset our Scope 1 and Scope 2 owned and operated upstream emissions (including the purchase of verified offset credits) but, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025 and Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s.

Industrial Projects

We are currently evaluating three potential medium to higher concentration industrial projects to sequester third-party emissions, which we anticipate will reach FID in either 2023 or 2024. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of approximately 16.7 million metric tons per year of captured CO_2e.

Two of the three projects are being developed by Verde CO2 under our development agreement with them. One of the three projects includes an agreement to acquire a carbon dioxide storage agreement covering approximately 20,000 acres of state-owned land and pore space leaseholds have been secured for the other two of these projects. We also anticipate that Class VI permit applications for each of these projects will be submitted during 2023. If each of these projects is approved at FID and we are able to secure sufficient external financing, and assuming definitive agreements are timely executed containing terms we believe are obtainable, we expect to initiate sequestration operations between 2025 and 2029.

Additional Projects

We are currently evaluating and have begun commercial discussions with respect to four additional CCUS projects that we anticipate may reach FID after 2024. If approved and implemented, these four projects would provide a combined forecasted annual sequestration volume of approximately 9.8 million metric tons per year of captured CO_2e.

If each of these projects is approved at FID and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect to begin sequestration operations between 2026 and 2029.

Our CCUS business of capturing and sequestering emissions from our operations and from operations of third parties is a critical component of our "closed-loop" approach to achieving our goal of net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s. We expect to continue to identify and evaluate additional CCUS projects and we believe that we will be able to complete a sufficient number of the above-described or other CCUS projects in order to meet our Scope 1, 2 and 3 emissions goals by the early 2030s. See "*— Path to Net Zero Emissions*" for a more detailed description of how we anticipate reaching our Scope 1, 2 and 3 emissions goals.

While the aggregate forecasted annual volume of CO_2e captured and sequestered from our twelve identified potential CCUS projects is approximately 30 million metric tons per year, which is more than our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream businesses, we do not anticipate achieving an aggregate yearly volume of sequestration of 30 million metric tons per year of captured CO_2e by the early 2030s. Furthermore, there can be no guarantee that we will be able to execute and complete any of the twelve identified CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2e sequestration to achieve our Scope 1, 2 and 3 emissions goals on the timelines we anticipate.

We estimate the aggregate investment required by us to fund a sufficient number of the identified potential CCUS projects in order to achieve our Scope 1, 2 and 3 emissions goals to be between approximately $1.3 billion and $1.8 billion over the next seven to ten years. We anticipate that some of these project costs will be borne by third-party investors in these projects, including emitters, landowners and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund the anticipated cost of these CCUS projects with a combination of cash flows from operations and up to 40% from external sources, which may include joint ventures, project-based equity partnerships and federal grants. We are able to moderate the capital required to fund our CCUS business, as our CCUS business model provides flexibility for us to selectively invest in only the sequestration component of a project or in the capture, transportation and sequestration components, depending on the scope of the project. Therefore, if sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline, which may result in an inability to achieve our Scope 1, 2 and 3 emissions goals on the timeline we anticipate.

Our CCUS business and all of our CCUS projects are in the early stages of development and while we have reached FID and entered into definitive agreements with respect to the Barnett Zero Project and reached internal FID for the Cotton Cove Project, we have not reached FID with respect to or entered into definitive agreements necessary to execute any of the other ten potential projects identified above. We may not be able to reach agreements on terms acceptable to us or achieve our projected timeline for commercial operations for these projects. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on certain financial and tax incentives provided by the U.S. federal government. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business.*"

To help us achieve our goal of becoming a leader in CCUS, we established a steering committee that includes two engineers renowned for their work in the development of CCUS projects: Dr. Paitoon (P.T.) Tontiwachwuthikul (Professor of Industrial & Process Systems Engineering & Fellow, Canadian Academy of Engineering) and Dr. Malcolm A. Wilson (Program Director, CO2 Management, Office of Energy & Environment (OEE), Adjunct Professor of Engineering and Graduate Studies). These individuals are professors at the University of Regina, a leading carbon capture research institution, and each has been engaged in CCUS for over 30 years.

For more information on our CCUS business, see "*— Our Operations — Carbon Capture, Utilization and Sequestration.*"

Path to Net Zero Emissions

We estimate that our owned and operated upstream Scope 1 and 2 annual emissions were approximately 1.70 Mtpy CO_2e as of December 31, 2022. This reflects a reduction of 0.5 Mtpy CO_2e from our estimated owned and operated upstream Scope 1 and Scope 2 annual emissions as of December 31, 2021 due to the implementation of "Pad of the Future" emissions reductions that began in the fourth quarter of 2021 and occurred throughout 2022. The 2022 estimate is also inclusive of the assets acquired in the Exxon Barnett Acquisition in June 2022.

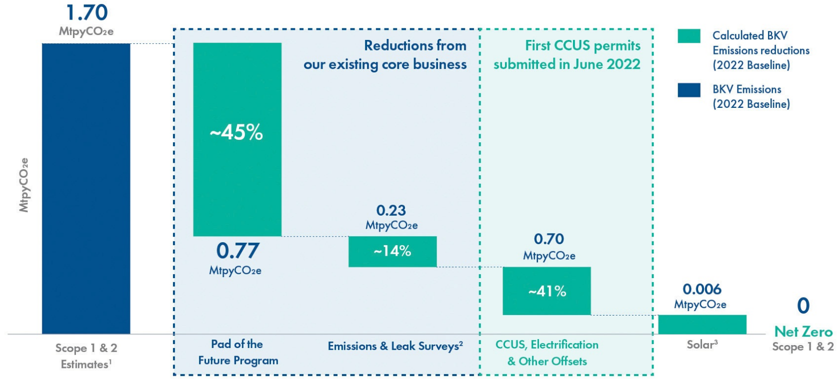
Our emissions estimates presented in this prospectus are based on information with respect to our owned and operated assets in the Barnett and NEPA through fiscal year 2022 and reported by BKV pursuant to the Subpart C and Subpart W, as applicable, requirements of the federal Clean Air Act GHG reporting program regulations of the EPA. These estimates fluctuate throughout the year and will be updated on an annual basis to reflect any changes in activity, inventory, production throughput, and emissions reduction retrofits or equipment modifications.

We estimate that our owned and operated upstream Scope 3 annual emissions were approximately 13.62 Mtpy CO_2e as of December 31, 2022. Our Scope 3 GHG emissions are currently estimated in accordance with IPIECA's "Sustainability reporting guidance for oil and gas industry," dated March 2020, specifically for Scope 3 emissions as estimated per Category 11 (Use of Sold Product). Scope 3 emissions estimated using source Category 11 represent the majority of Scope 3 emissions from our upstream operations with minor contributions from other source categories. Additionally, our estimated Scope 3 emissions calculations assume that all natural gas produced is combusted and does not account for other potential end use of natural gas. Scope 3 mass emissions are calculated using the EPA's prescribed emissions factors for the speciated natural gas (methane and ethane) as well as NGLs assuming Y-grade NGLs. CO_2e emissions are estimated using AR4 Global Warming Potentials, similar to those used by the EPA. Our projected Scope 3 CO_2e annual emissions are estimated at an approximated year-end net production volume of 900 MMcfe/d, with an approximate split of 80% natural gas (95% methane and 5% ethane) and 20% NGLs. Our NGL constituents are estimated based on average constituent NGL barrel. Allocating the entire 900 MMcfe/d towards combustion as the end use, applying suitable combustion emission factors from the EPA, and using AR4 GWPs, Scope 3 annual emissions from our owned and operated upstream operations are estimated to be approximately 13.62 Mtpy CO_2e. We currently engage third party consultants to develop and review our Scope 3 emissions estimates.

The charts below reflect (i) our owned and operated upstream Scope 1 and 2 annual emissions estimates as of December 31, 2022, and (ii) our owned and operated upstream Scope 3 annual emissions estimates as of December 31, 2022, in each case, inclusive of the emissions generated by the assets acquired in the Exxon Barnett Acquisition. These two charts also reflect our intended path to net zero Scope 1 and 2 emissions by the end of 2025 and net zero Scope 1, 2 and 3 emissions by the early 2030s, in each case, for our owned and operated upstream businesses. As part of our "closed-loop" approach to our emissions goals, we intend to achieve these goals through our "Pad of the Future" emissions reductions, reductions attributable to emissions monitoring and leak surveys, emissions offsets from installing solar power and executing CCUS projects to sequester our and third-party emissions.

BKV's Planned Path to Net Zero (Scope 1 & 2): Barnett and NEPA Production

Based on total BKV upstream emission estimates in the Barnett and NEPA



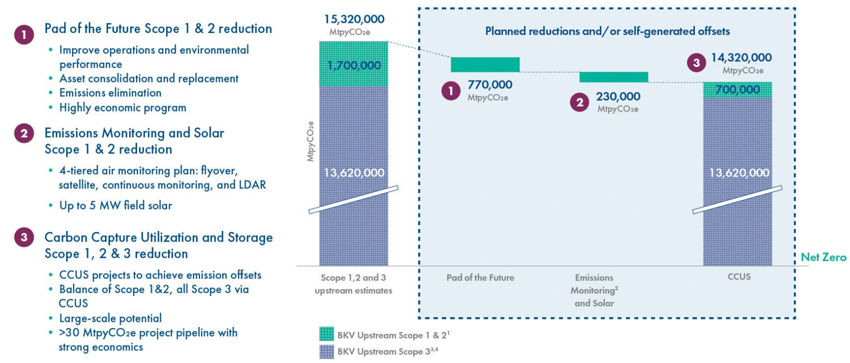
(1) Scope 1 and 2 calculated emissions are based on 830 MMscf/d production volume (net sales) for 2022 Subpart W in the Barnett and 144 MMscf/d production volume for 2022 Subpart W in NEPA.

(2) Emissions surveys to accomplish a one-to-two month leakage review period versus 12-month period which must have regulatory updates (current proposed OOOO.b,c) to include continuous flyover/satellite technology sensitivities.

(3) Installation of a 2.5 MW to 5 MW solar farm. We have obtained permits for 2.5 MW and are in the process of obtaining permits for the remaining 2.5 MW.

BKV's Planned Path to Net Zero (Scope 1, 2 & 3): Barnett and NEPA Production

Based on total BKV upstream emission estimates in the Barnett and NEPA



(1) Scope 1 and 2 calculated emissions are based on 830 MMscf/d production volume for 2022 Subpart W in the Barnett and 144 MMscf/d production volume for 2022 Subpart W in NEPA.

(2) Emissions surveys to accomplish a one-to-two month leakage review period versus 12-month period which must have regulatory updates (current proposed OOOO.b,c) to include continuous flyover/satellite technology sensitivities. Installation of a 2.5 MW to 5 MW solar farm. We have obtained permits for 2.5 MW and are in the process of obtaining permits for the remaining 2.5 MW.

(3) Scope 3 calculated emissions are based on an estimated net production rate of approximately 900 MMcfe/d (approximately 720 MMscf/d of natural gas and 31,000 Bbl/day of NGLs).

(4) Scope 3 calculated emissions are estimated assuming fuel-based usage of all produced natural gas and

NGLs. Approximately 58% of NGLs are assumed to be combusted for fuel while 100% of all natural gas sold is assumed to be combusted for fuel. Scope 3 emissions estimation methodology is therefore considered to be conservative.

Planned Path to Net Zero (Scope 1 and 2)

Pad of the Future. Our “Pad of the Future” program implements pad level design improvements to reduce pad level usage of natural gas, reduce GHG emissions, and maintain operational continuity. As of December 31, 2022, we had implemented elements of our “Pad of the Future” on approximately 2,500 of our existing wells, thereby eliminating an aggregate of approximately 0.38 Mtpy CO_2e in annual GHG emissions from commencement in the fourth quarter of 2021 through such date. Our estimated emissions reduction from year-end 2021 to year-end 2022 was primarily the result of our “Pad of the Future” program. These reductions are calculated by using our pneumatic and other pad inventories, and such emissions are factored to be eliminated once the system has been converted from natural gas supplied to compressed air or electric.

We expect to implement elements of our “Pad of the Future” program on more than 6,000 of our existing wells (more than 8,000 pneumatic devices and 2,000 pneumatic pumps) by the end of 2025 for an aggregate estimated cost of approximately $35 to $40 million. Once this expansion is completed, we expect to eliminate approximately 0.77 Mtpy CO_2e, or approximately 45%, of the currently estimated Scope 1 and 2 annual emissions from our owned and operated upstream businesses.

Emissions Monitoring and Solar. Our leak detection and repair emissions monitoring program involves continuous ground-based instrument monitoring, satellite-based monitoring, aerial flyovers, and on the ground leak detection and repair inspections. In addition, we expect to install a 2.5 MW to 5 MW solar farm, which is scheduled to begin generating power in 2024. We have obtained permits for 2.5 MW and are in the process of obtaining permits for the remaining 2.5 MW. For every 1,000 kilowatt-hours of electricity produced by an eligible solar facility, one SREC is awarded. For a solar facility to be credited with that SREC, the system must be certified and registered by state agencies. The solar farm is expected to generate enough SRECs, when combined with our leak detection and repair emissions monitoring program, to offset approximately 0.23 Mtpy CO_2e in GHG emissions from our owned and operated upstream businesses. Solar facilities may be subject to increasingly arduous regulatory requirements, including additional permitting requirements.

CCUS. Further, as discussed under “— *Carbon Capture, Utilization and Sequestration*” above, we believe that the Barnett Zero Project and the Cotton Cove Project, together with the three additional near-term NGP projects for the capture and sequestration of third-party emissions that we have identified, have a combined annual forecasted sequestration volume of approximately 1.23 Mtpy CO_2e. We believe that these projects are capable of offsetting by the end of 2025 more than the approximately 0.70 Mtpy CO_2e Scope 1 and 2 emissions from our owned and operated upstream businesses that we currently estimate will remain after taking into account the expected emissions reductions from our “Pad of the Future” program and emissions monitoring and leak surveys and emissions offsets from the installation of solar power. Although no definitive agreements have been entered into with respect to any of these additional NGP projects, we expect these projects to reach FID in either 2023 or 2024. A significant portion of the carbon capture infrastructure necessary to execute these potential NGP projects already exists and, as discussed above, we continue to accomplish important milestones consistent with our projected timeline. Therefore, if approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2025. If we are unable to complete each of these three projects before December 31, 2025, we may still reach our Scope 1 and 2 emissions goals with less than all of these projects completed as, individually, the annual forecasted sequestration volume by the end of 2025 of (i) the Barnett Zero Project is 0.21 Mtpy CO_2e, (ii) the Cotton Cove Project is 0.05 Mtpy CO_2e and (iii) the three near-term NGP projects is .07, 0.27 and 0.64 Mtpy CO_2e, respectively. However, we have not secured external funding, reached FID or entered into definitive agreements for any of these three additional NGP projects. We may not complete all or any of these three additional NGP projects, the Barnett Zero Project or the Cotton Cove Project by December 31, 2025, in which case, we may consider alternatives to offset our Scope 1 and Scope 2 owned and operated upstream emissions (including the purchase of verified offset credits or pursuing alternative CCUS projects) but, ultimately, we may not be able to achieve our goal of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025.

Planned Path to Net Zero (Scope 1, 2 and 3)

We also aspire to offset the Scope 3 emissions impact of our owned and operated upstream businesses by the early 2030s, which we estimate to be approximately 13.62 Mtpy CO_2e annually as of December 31, 2022, and our CCUS business of capturing and sequestering our and third-party emissions is a critical component to achieving this net zero goal. This aspiration to offset the Scope 3 emissions of our owned and operated upstream businesses by the early 2030s is limited to our Category 11 (Use of Sold Product) emissions. As discussed in "— *Carbon Capture, Utilization and Sequestration,*" above, we have identified twelve potential CCUS projects that we believe are commercially viable that we estimate would have a combined forecasted annual volume of carbon capture and sequestration of approximately 30 Mtpy CO_2e (which exceeds our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream businesses). This forecast of annual sequestration volume of our and third-party emissions includes all twelve of our identified CCUS projects, including the Barnett Zero Project, the Cotton Cove Project and the three potential near-term NGP projects described in "*— Planned Path to Net Zero (Scope 1 and 2)*" above. While we expect to pursue a sufficient number of CCUS projects to achieve our Scope 3 emissions goal, we do not anticipate achieving an aggregate yearly volume of sequestration of 30 million metric tons per year of captured CO_2e before the early 2030s.

Large scale CCUS projects are subject to numerous risks and uncertainties, including securing third-party financing, reaching definitive agreements with third parties and obtaining necessary permits and other regulatory approvals, and we may be unable to execute on some or all of these projects, including the projects for which we have reached FID, on the timeline we anticipate, on terms acceptable to us or at all. There can be no guarantee that we will be able to execute and complete any of these identified CCUS projects and there can be no guarantee that we will be able to achieve our net zero Scope 1, 2 and 3 emissions goals. The projected timeline for commercial operations of our CCUS projects depends in part on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. If sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline. If we are not able to complete CCUS projects having a sufficient forecasted volume of carbon capture to offset our Scope 1, 2 and 3 annual emissions on the timeline and upon terms that we believe are obtainable, we may not be able to achieve our goal of net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s.

In addition, our path to net zero does not address GHG emissions from other business operations, including our midstream, power or CCUS business operations, but solely GHG emissions relating to our owned and operated upstream businesses. Although we believe our current path to net zero will be sufficient to reduce emissions related to our existing owned and operated upstream businesses, the future growth of our natural gas production assets will result in additional CO_2e emissions. We believe our approach to reducing the emissions from our owned and operated upstream operations is repeatable and scalable. Through continued investment and expansion of our "Pad of the Future" program, our emissions and leak surveys as well as additional CCUS and solar projects, we believe will be able to offset any such additional emissions from our owned and operated upstream businesses resulting from our continued growth.

Business Strategy

Our strategy is to create value for our stockholders by managing and growing our integrated asset base and focusing on our net zero objectives. Our strategy has the following principal elements:

- **Deliver robust returns to stockholders.** We intend to prioritize delivering strong returns to our stockholders through our dividend policy and focus on creating stockholder value. See "*Dividend Policy*." We believe our operational expertise in successfully drilling and refracturing wells, acquiring and integrating assets purchased at attractive valuations and maintaining financial discipline will underpin our ability to meet our stockholder return goals. Our integrated businesses and natural gas-weighted, low-decline PDP reserves collectively reduce our downside risk while providing asymmetric upside returns from the confluence of commodity price uplift potential, operational improvement and development opportunities, and future accretive acquisition opportunities. The payment of any future dividends on our common stock will be at the discretion of our board of directors and may vary significantly from quarter to quarter and may be zero. Any determination to pay dividends and the amount of any such dividends will depend on, among other factors, the restrictions under our Term Loan Credit Agreement and the Revolving Credit Agreement, as described under "*Dividend Policy*." See "*Risk Factors — Risks Related to the Offering and Our Common Stock.*"

- **Optimize the value of our core businesses.** We utilize technology and data analysis to enhance our assets and operations, which we believe improves operational efficiencies, reduces our emissions and helps us realize our operational and financial goals as we continue to scale our business. For example, our "Pad of the Future" program, which includes conversion of natural gas-powered instrument pneumatics to compressed air power instruments on existing pads, combined with emission and leak surveys, is expected to eliminate or reduce approximately 1.15 Mtpy CO_2e of our annual GHG emissions by the end of 2025. Our "Pad of the Future" application also improves pad efficiencies and operating revenue. As of the year ended December 31, 2022, employing technology and operational excellence, we reduced our lease operating costs in the Barnett (excluding the 2022 Barnett Assets) by 4% based on the last 12-month rolling average as compared to the 10-month period of our ownership of the 2020 Barnett Assets in 2020, prior to BKV assuming operatorship, and in NEPA, we reduced our lease operating costs by 25% since January 2019, based on 12-month rolling average for this time period compared to the prior operatorship 12-month rolling average ending in January 2019. These lease operating cost reductions in the Barnett and NEPA include absorbing cost increases of 13% due to inflation. Additionally, our refrac and long lateral drill programs have allowed us to organically grow our reserves base. As of December 31, 2022, our Barnett refrac program has added 643 Bcfe of proved reserves since its inception in early 2021, as well as an estimated 520 Bcfe of probable reserves and 133 Bcfe of possible reserves. As of December 31, 2022, our Barnett refrac program has an average of $0.79/Mcfe in finding and development costs with respect to proved reserves. This refrac program employs specifically designed perforating technology and a suite of innovative refrac techniques, as well as advanced refrac designs and diversion methods to maximize reserve recovery and economics from legacy Barnett wells. Our Barnett new well drilling program has added 1.0 Tcfe of proved reserves since our entry into the Barnett, with a total estimate of approximately 677 Bcfe of probable reserves and 267 Bcfe of possible reserves. By combining our reserves into a growing asset base with vertically integrated components, we believe we can enhance margins and create a "closed loop" business that reduces Scope 1 and 2 emissions from our owned and operated upstream businesses and captures margin across the value chain. Estimates of probable and possible reserves are inherently imprecise and are more uncertain than proved reserves but have not been adjusted for risk due to that uncertainty, and therefore they may not be comparable with each other and should not be summed either together or with estimates of proved reserves. For more information regarding the presentation of probable and possible reserves, see "*— Preparation of Reserves Estimates and Internal Controls.*"

- **Grow through opportunistic, synergistic acquisitions.** A significant element of our business strategy is gaining scale through accretive acquisitions. We have a track record of growth through acquisitions, which we believe have been at attractive valuations. Since 2016, we have completed 19 acquisitions and two CCUS partnerships, resulting in greater than a 100% compound annual growth rate of Adjusted EBITDAX as of December 31, 2022. We believe our business model, management team experience and application of technology enable us to quickly and efficiently integrate additional upstream, midstream and power assets into our business.

- **Maintain a disciplined financial strategy.** We believe we can execute on our business plan and grow our business while continuing to generate substantial Adjusted Free Cash Flow. We target a Maintenance Reinvestment Rate of less than 30% and an Upstream Reinvestment Rate of less than 40%. We are focused on our goal of maintaining a conservative financial profile, with a long-term leverage target of less than 1.0x Total Net Leverage Ratio. Although we may allow our leverage ratio to exceed our target in connection with a strategic acquisition, we would seek to return our leverage level to below 1.0x as soon as reasonably possible thereafter through Adjusted Free Cash Flow and, if needed, reduced activity levels. To support the generation of future Adjusted Free Cash Flow, we have a policy of hedging approximately 25% to 60% of our production volumes over a given

12 to 24-month period. We believe our capital efficient project inventory, low-decline natural gas production and multiple, integrated business lines will provide consistent returns through varying business cycles. We intend to apply our cash flows to manage our indebtedness in line with our leverage target, fund our capital expenditure program, enhance stockholder value and execute opportunistic acquisitions across our four business lines. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See "*Prospectus Summary — Summary Historical and Unaudited Pro Forma Financial Information — Non-GAAP Financial Measures*" for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

- **Focus on our net zero objectives.** We seek to apply our integrated business model, CCUS projects, and carbon-negative initiatives to realize Scope 1 and 2 net zero upstream owned and operated emissions by the end of 2025. We believe we can achieve this through reductions in and offsets to our upstream emissions from our "Pad of the Future" emissions reductions program and emissions monitoring and leak surveys, installing solar power and executing CCUS projects. We believe that carbon emissions within the United States can be reduced substantially through carbon capture on natural gas production, power plants, processing facilities and other energy and industrial infrastructure. As such, in addition to lowering emissions in our owned and operated upstream businesses, CCUS for third parties has become a core focus of our business plan. We expect our CCUS projects to represent a meaningful portion of our budgeted capital expenditures going forward as we advance our long-term goal of offsetting Scope 3 emissions from our owned and operated upstream businesses.
- **Encourage innovation.** Our distinctive culture encourages innovation with a value-driven focus that feeds into our competitive advantage. For example, our emphasis on the efficient application of modern technology led to the development of our "Pad of the Future" program, our advancements in Barnett refracs and other operational improvements. We intend to continue to develop, retain and add to our already talented, experienced and forward-thinking employees. Our unified team and mantra of "Being a force for good" underpin our core values and provides us with confidence in our ability to successfully manage and grow our business.

Competitive Strengths

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

- **Integrated asset base well positioned for sustainable growth.** Our upstream, midstream and power asset bases reside in geographically concentrated areas with numerous asset acquisition opportunities in close proximity. Our proven ability to successfully negotiate, close and integrate these acquisition opportunities quickly and cost effectively will allow us to continue to grow our portfolio of assets synergistically. We believe that scale and the continued application of technological developments and operational excellence, combined with stable, low-decline production profiles, will continue to generate significant capital efficient development opportunities in the Barnett and NEPA.
- **High quality, low decline assets serving key demand markets.** Through a series of accretive acquisitions, we have established an extensive and largely contiguous acreage position in two key markets, the Barnett and NEPA. Our Barnett assets cover approximately 458,000 net acres, with an approximately 80.25% Effective NRI, and are located in close proximity to key Gulf Coast industrial and LNG demand centers. Our NEPA assets consist of 37,000 net acres in one of the most prolific parts of the Marcellus Shale and are located within less than 200 miles to key demand markets in the U.S. Northeast. We believe the geologic, operational and engineering risks associated with our leasehold acreage have been significantly mitigated through historical development activity. Our PDP reserves had an estimated 7.3% year-over-year average base decline rate over the next 10 years as of December 31, 2022. Additionally, we have an inventory of over 10 years of refrac and new drill locations within our core acreage that give us the flexibility to maintain or slightly grow current production levels, depending on the commodity cycle.
- **Lower emissions energy production.** We are focused on achieving Scope 1 and 2 net zero emissions from our owned and operated upstream businesses by the end of 2025. We believe we have a comprehensive ESG program, which is overseen and directed by an executive ESG steering committee.

In 2021, we certified our entire NEPA production and, in 2022, we certified a portion of our Barnett production and, in each case, achieved a Gold rating with Project Canary's TrustWell environmental assessment (Project Canary is an environmental certification and ESG data company). This is the second highest rating a company can receive for its production, qualifying the certified portion of our natural gas production as Responsibly Sourced Gas ("RSG"), or gas that is considered to be less carbon-intensive due to the way it was produced. In addition, we intend to advance the market for our produced gas beyond RSG and its current certification towards a Scope 1, 2 and 3 carbon-neutral natural gas product, which we refer to as Measured Net-Zero ("MNZ") gas. MNZ gas would be achieved by offsetting the estimated emissions associated with the production, gathering, and boosting of our RSG as well as the estimated emissions from transmission (and distribution, if applicable) of our sold gas through our CCUS projects as described in "—*Path to Net Zero Emissions,*" with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We believe MNZ gas provides a fully decarbonized, certified, and qualified fuel that is a differentiated and premium product. We expect that both RSG and MNZ could command a premium in the marketplace and we have already executed a letter of intent with a potential buyer for the sale of our anticipated MNZ gas. Additionally, we have a plan to achieve net zero Scope 1 and 2 owned and operated upstream emissions by the end of 2025 based on our "Pad of the Future" program, emissions monitoring and leak surveys, installing solar power and executing CCUS projects. However, if we are not able to complete CCUS projects having sufficient sequestration volumes of CO_2 on this timeline, we may consider alternatives to offset our Scope 1 and Scope 2 emissions (including the purchase of verified offset credits) but, ultimately, we may not be able to achieve this goal or produce MNZ gas.

- **Efficient use of capital.** Our deep, high-graded inventory of refrac opportunities coupled with our inventory of new drill locations allow us to create meaningful additional cash flow with comparatively modest additional capital investments. We utilize operational improvements such as operational process and procurement efficiencies, use of existing field infrastructure, innovative and cost-effective refrac techniques and designs (including diversion methods), drilling long laterals in the Barnett, and optimizing available midstream capacity to further maximize our capital efficiency. Through our midstream, power and CCUS business lines, we are capturing margin across the value chain.
- **Well capitalized and conservative balance sheet.** As of December 31, 2022, we had a Total Net Leverage Ratio of 1.00x. Following the completion of this offering, we intend to continue to maintain a strong balance sheet and fund our upstream, midstream and power operations predominantly with internally generated cash flows. We believe that the low decline, predictable nature of our upstream production profile, combined with our hedging plan and reinvestment rate targets, will allow us to successfully meet our leverage goals.
- **High caliber and proven management team.** We maintain a highly experienced and knowledgeable management team with an average of over 25 years of experience among our senior management team. Our leadership team has significant experience managing integrated energy and power assets for large-scale enterprises, including companies such as PTT Exploration and Production Public Company Limited ("PTT Exploration") and BP p.l.c. ("BP"). Furthermore, our sponsor, Banpu, one of Asia Pacific's largest integrated energy companies, provides us with unique and valuable insights into optimizing our integrated energy business.

Recent Developments

Barnett Zero CCUS Project with EnLink

On June 8, 2022, BKV dCarbon Ventures and EnLink reached FID to develop our first high concentration CCUS project and entered into a definitive agreement to dispose of, and geologically sequester, CO_2 generated as a byproduct of the production of our natural gas in the Barnett. This CCUS project, which we refer to as the Barnett Zero Project, will separate CO_2 from substantially all of our EnLink-gathered natural gas production, which we expect to achieve an average sequestration rate of up to approximately 210,000 metric tons of CO_2e per year. We estimate the total investment required by us for the Barnett Zero Project to be between $29.0 and $34.0 million. We are targeting commencement of CO_2 sequestration activities by December 2023, subject to our ability to secure all required permits, at which point we expect this project will be one of the first permanent commercial CO_2 disposal and sequestration projects to come online in the United States.

Exxon Barnett Acquisition

On June 30, 2022, we closed the Exxon Barnett Acquisition of natural gas upstream and associated midstream infrastructure in the Barnett from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation, for a total purchase price of $750.0 million, plus additional contingent consideration of up to $50.0 million depending on future natural gas prices. Pursuant to the Exxon Barnett Acquisition, we acquired approximately 165,000 total net acres in the State of Texas that are approximately 99% held by production and located primarily in Tarrant, Johnson and Parker counties, with additional smaller positions in Jack, Wise, Denton, Erath, Hood and Ellis counties. These upstream assets include low decline wells, ideal for delivering consistent cash flow, and high average working interests of approximately 94% in over 2,100 operated wells. The Exxon Barnett Acquisition also included approximately 778 miles of gathering pipelines and compression and processing midstream infrastructure with, as of December 31, 2022, over 450 MMcf/d of throughput capacity and approximately 26 MMcf/d of third-party production being gathered on the system. In connection with the Exxon Barnett Acquisition, we entered into the Term Loan Credit Agreement (as defined herein) with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent. The Term Loan Credit Agreement includes up to $600.0 million of commitments for term loans to be used solely to fund a portion of the purchase price for the Exxon Barnett Acquisition and other costs and expenses associated with the acquisition. As of April 13, 2023, there was $570.0 million in aggregate principal amount outstanding under the Term Loan Credit Agreement. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Term Loan Credit Agreement*" for more information.

CCUS Project Development with Verde CO2

On August 22, 2022, we entered into a development agreement with Verde CO2 to identify, evaluate and develop CCUS projects throughout the United States. We believe our agreement with Verde CO2 will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration. Pursuant to the development agreement, Verde CO2 will be responsible for the sourcing, development, performance and ongoing management of such CCUS projects and BKV dCarbon Ventures will provide funding for such projects. As of April 6, 2023, we have paid $17.3 million to Verde CO2 under the development agreement, and we expect to invest up to $250.0 million over the next three years to fund efforts by BKVerde, a subsidiary of BKV dCarbon Ventures, to efficiently identify and evaluate feasible CCUS projects, and to execute on those projects. We expect to fund BKVerde through BKV's cash flow from operations but may also obtain funding from external sources.

Revolving Credit Agreement

On August 24, 2022, we entered into a Revolving Credit Agreement (as amended by that certain First Amendment to Revolving Credit Agreement dated as of November 11, 2022, the "Revolving Credit Agreement") with Bangkok Bank Public Company Limited (New York Branch), as the administrative agent and sole initial lender. The Revolving Credit Agreement includes $100.0 million of commitments for unsecured revolving loans used for short-term working capital and operating needs. As of April 13, 2023, no amount was outstanding under the Revolving Credit Agreement. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Revolving Credit Agreement*" for more additional information regarding the Revolving Credit Agreement.

Cotton Cove CCUS Project

On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of, and geologically sequester CO_2 generated as a byproduct of our natural gas production in the

Barnett and will utilize our newly acquired BKV Midstream assets to do so. We have multiple company-owned pore space opportunities for CO_2 injection and we estimate the Cotton Cove Project will geologically sequester up to approximately 45,000 metric tons of CO_2e per year. We currently estimate the total investment required by us for the Cotton Cove Project to be between approximately $14.0 and $24.0 million. We are targeting commencement of CO_2 sequestration activities by the first half of 2024, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects under evaluation as described in "*— Our Operations — Carbon Capture, Utilization and Sequestration.*"

Letter of Intent with EEMNA

On November 11, 2022, we entered into a non-binding letter of intent with EEMNA to build a framework for verifiable environmental attributes with the use of carbon credits applied to natural gas energy. Under this framework, we intend to measure, reduce and verify emissions using operational technologies, such as continuous emissions monitoring. In addition, we intend to advance our production of RSG towards a fully carbon-neutral natural gas production which we refer to as Measured Net-Zero ("MNZ") gas. MNZ gas would be achieved by offsetting the estimated emissions associated with the production, gathering and boosting of our RSG as well as the estimated emissions from transmission (and distribution, if applicable) of our sold gas through our CCUS projects, with the requisite volume of offsetting environmental attributes being third-party certified. We believe MNZ provides a fully decarbonized, certified, and qualified fuel that is a differentiated and premium product attractive to LNG buyers, gas utilities, power utilities or other end-users. Project Canary or another environmental certification and ESG data company will reconcile sensing technologies and measure, analyze, and report the environmental attributes of the sequestrated carbon to support the MNZ gas. Under the letter of intent, we anticipate eventually selling MNZ gas to EEMNA for marketing to end-users.

Our History

In June 2015, our Chief Executive Officer, Chris Kalnin, and Banpu founded our predecessor, BKV O&G, a Delaware partnership developed for oil and gas investments owned primarily by Banpu and managed by Kalnin Ventures, with the goal of creating long-term sustainable value in the energy industry.

In 2016, BKV O&G acquired from Range Resources a 29.4% interest in certain midstream assets and an approximately 24% interest in certain upstream assets in the Marcellus Chaffee Corners area that are operated by Repsol. From 2017 to 2019, BKV completed a series of other accretive acquisitions, including two major acquisitions of upstream and midstream assets in NEPA from Carrizo Oil and Gas and its non-operated partner, Reliance Industries, and BKV O&G devoted its time to strengthening its technological, exploration, production and operational capabilities.

On May 1, 2020, we completed a corporate restructuring in which we converted all of the interests and assets owned by BKV O&G (the "BKV O&G Conversion") and also acquired Kalnin Ventures (the "KV Acquisition"). The BKV O&G Conversion and the KV Acquisition resulted in our formation as a new consolidated corporate entity, BKV Corporation. See "*— The Corporatization Event*" for more information about our corporate restructuring.

In October 2020, we became one of the largest natural gas producers by volume in the Barnett, following our acquisition of more than 289,000 net acres, 3,850 producing operated wells and related upstream assets in the Barnett from Devon Energy (the "Devon Barnett Acquisition") for a cash purchase price of $570.0 million.

In July 2021, we launched our natural gas-based power generation business with the formation of BKV-BPP Power, a joint venture owned 50% by us and 50% by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu. In November 2021, BKV-BPP Power acquired Temple Generation Intermediate Holdings II, LLC, the owner of 100% of the interests in Temple I, a combined cycle gas turbine and steam turbine power plant located in the ERCOT North Zone in Temple, Texas.

In September 2021, we purchased a non-operated interest spanning over 3,000 net acres from Black Falcon Energy, LLC, a managing company for Jamestown Resources, LLC, Larchmont Resources, LLC and Pelican Energy, LLC in the Barnett and NEPA.

In March 2022, we launched our CCUS business line, BKV dCarbon Ventures, and we reached FID and entered into a definitive agreement in June 2022 in connection with our first CCUS project, the Barnett Zero Project, with EnLink to dispose of, and geologically sequester, CO_2 generated as a byproduct of the production of our EnLink-gathered natural gas in the Barnett. Following commencement of commercial operations of our project with EnLink, we intend to use this project as a prototype for modular projects that can be repeated and quickly scaled.

In June 2022, we consummated the Exxon Barnett Acquisition, which also substantially grew our natural gas midstream business. Pursuant to the Exxon Barnett Acquisition, we acquired approximately 165,000 total net acres and 2,100 operated wells in the State of Texas that are located primarily in Tarrant, Johnson and Parker counties, with additional smaller positions in Jack, Wise, Denton, Erath, Hood and Ellis counties. The Exxon Barnett Acquisition also included the addition of 129 employees and approximately 778 miles of gathering pipelines, compression and processing midstream infrastructure.

In August 2022, we entered into a development agreement with Verde CO2 to identify, evaluate and develop CCUS projects throughout the United States. We believe our agreement with Verde CO2 will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration and aligns with our goal to reach net zero owned and operated upstream emissions.

In October 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project to dispose of, and geologically sequester, CO_2 generated as a byproduct of the production of our natural gas in the Barnett and will utilize our newly acquired BKV Midstream assets to do so.

In November 2022, we entered into a non-binding letter of intent with EEMNA to build a framework for verifiable environmental attributes with the use of carbon credits applied to natural gas energy. We intend to achieve the development of MNZ gas by offsetting the estimated emissions associated with the production, gathering and boosting of our RSG as well as the estimated emissions from transmission (and distribution, if applicable) of our sold gas through our CCUS projects, with the requisite volume of offsetting environmental attributes being third-party certified. We anticipate eventually selling MNZ gas to EEMNA for marketing to end-users.

The Corporatization Event

Prior to May 1, 2020, BKV O&G held 100% of the outstanding equity interests in BKV Chaffee, BKV Chelsea, BKV Operating and BKV Barnett (the “BKV O&G Group”). During this period, Banpu held approximately 97% of BKV O&G’s limited partner interests, and Kalnin Capital Partners, L.P. (the “General Partner”) held BKV O&G’s general partner interest.

On May 1, 2020, Banpu and the General Partner incorporated BKV Corporation and restructured BKV O&G through a contribution by Banpu, the other limited partners and the General Partner of all of the partnership interests in BKV O&G to BKV Corporation in exchange for common stock of BKV Corporation. In addition, Kalnin Ventures, which previously managed BKV O&G, was contributed to BKV Corporation in exchange for BKV Corporation common stock. As a result of these transactions, as of May 1, 2020, the BKV O&G Group and Kalnin Ventures became wholly-owned subsidiaries of BKV Corporation. We refer to this series of transactions collectively as the “Corporatization Event.”

Our Relationship with Banpu

BNAC, our majority stockholder, is an indirect, wholly owned subsidiary of Banpu, our ultimate parent company. Immediately prior to this offering, Banpu owned approximately 95.9% of our common stock and will own approximately % at the completion of this offering (or approximately % if the underwriters exercise in full their option to purchase additional shares of our common stock). Banpu has informed us that although it may reduce a portion of its ownership position over time, it intends to remain a long-term stockholder and supporter of BKV. However, Banpu is not obligated to continue to hold all or any portion of its ownership in the Company. If, after this initial public offering, Banpu and its wholly owned subsidiaries cease to own at least 51% of our equity interests, or if they allow any lien to exist on our equity interests that they own, such event will be an event of default under the Term Loan Credit Agreement and the Revolving Credit Agreement. See "*Risk Factors — Risks Related to Our Relationship with Banpu and its Affiliates.*"

Banpu is a multi-billion U.S. dollar market cap energy company publicly traded in Thailand. With nearly four decades of experience in business operations covering 10 countries across the Pacific Rim region and the United States, Banpu is an international versatile energy provider committed to its Greener & Smarter strategy, which prioritizes environmentally sustainable businesses and leverages smart technologies and innovations.

Banpu also owns approximately 78.66% of Banpu Power. Banpu Power is a public company listed on the Stock Exchange of Thailand. Banpu Power is the owner of BPPUS, our 50/50 partner in BKV-BPP Power.

See "*Certain Relationships and Related Party Transactions*" for additional information regarding our relationship with Banpu.

Our Operations

Natural Gas Production

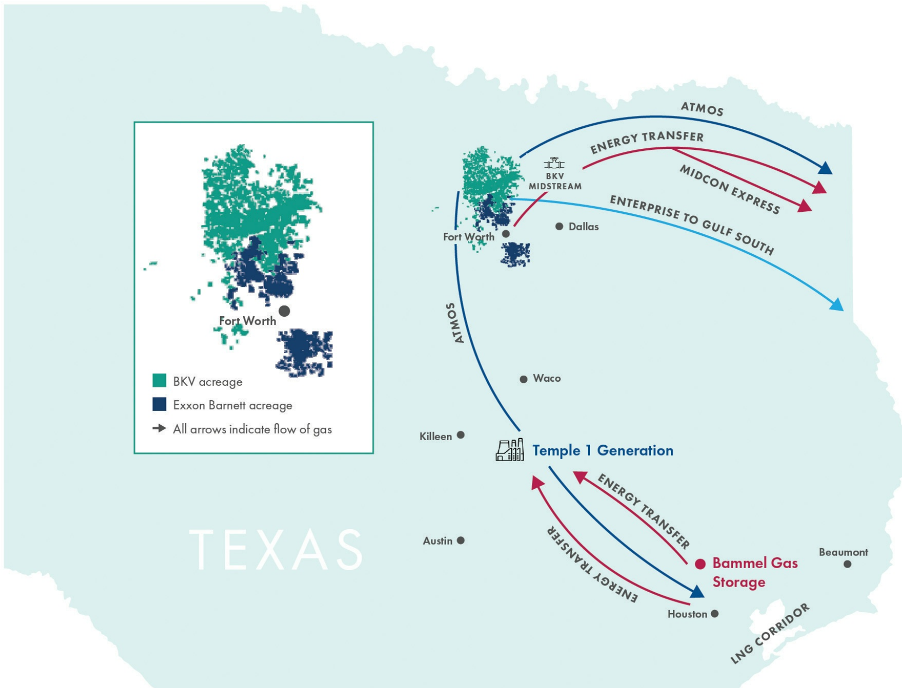
Our Geographic Focus

We are engaged in the acquisition, operation and development of natural gas and NGL properties located primarily in the Barnett (approximately 458,000 net acres) and NEPA (approximately 37,000 net acres) with a combined total company net production (after giving effect to the Exxon Barnett Acquisition) of approximately 871.9 MMcfe/d for the year ended December 31, 2022. In addition, we own an aggregate of approximately 4,500 net mineral fee acres located in the Barnett and NEPA. The Barnett has a diversified production stream of natural gas and NGLs located approximately 300 miles from major Gulf Coast industrial centers and LNG export markets. NEPA is composed predominantly of organically rich shale and is generally acknowledged as one of North America's largest and richest sources of natural gas.

Our upstream assets are predominantly located in the Barnett, which is where horizontal drilling was pioneered and which has the advantage of more than 15 years of technological advancements, proximity to demand hubs and a significant amount of midstream and other infrastructure in place. We also enjoy an average 6.7% 10-year Barnett base production decline on a current production base (after giving effect to the Exxon Barnett Acquisition) of approximately 732.7 MMcfe/d. Using modern technologies, we can drill and complete more profitably and successfully with longer laterals, optimal 750 foot down hole well spacing and latest shale fracturing designs. More than a decade of technological advancements since the discovery of the Barnett, combined with significant remaining gas and NGL resources in place, have created a highly capital efficient opportunity to re-stimulate legacy wellbores to meaningfully increase production and enhance recovery factors and reserves. We also have negotiated a midstream contract, covering 44% of our Barnett acreage, that offers incentive gathering and processing rates for new drills and restimulations, enhancing our margins and project economics alike. We entered the Barnett in October of 2020, through our completion of the Devon Barnett Acquisition. As of December 31, 2022, we had 167 proved undeveloped, 147 probable undeveloped and 82 possible horizontal locations and 584 proved developed non-producing, 743 probable and 234 possible horizontal refrac candidates in the Barnett, including those acquired in the Exxon Barnett Acquisition.

We are the largest producer of natural gas in the Barnett, based on publicly reported gross production volume as of October 31, 2022. During the year ended December 31, 2022, our Barnett properties, including both operated and non-operated wells, produced 228.7 Bcfe (or an average of 626.3 MMcfe/d). During the year ended December 31, 2021, we produced 190.1 Bcfe (or an average of 520.9 MMcfe/d) from our Barnett properties, including both operated and non-operated wells. We did not drill any of our own operated wells in our Barnett properties during 2021 and drilled 115 wells in 2022. Additionally, in November 2020, we began a restimulation program to develop economic incremental reserves in existing wellbores and arrest the overall field production decline. In 2021 and 2022, we led the industry in number of executed horizontal restimulations by completing 140 and 162, according to public completion reports.

The image below reflects our Barnett acreage that was acquired in the 2020 Barnett Acquisition (Green) and the Exxon Barnett Acquisition (Blue), with the arrows indicating the direction of flow to existing markets and identifying the respective third parties with which BKV has secured downstream capacities. The image reflects how we are now positioned in the core of the Barnett with transportation to key gulf coast markets. Transportation to the East and the South provide key flexibility and optionality for gas transportation out of the basin. This strategically positions us geographically to utilize existing infrastructure to the gulf without needing to rely on new-build pipelines such as in the Permian and Haynesville.



In NEPA, we have built our position through 12 accretive acquisitions since May 2016. We have an attractive production base comprising approximately 37,000 net acres located primarily in Wyoming, Susquehanna and Bradford counties, Pennsylvania, in one of the most prolific areas of the play. With respect to our operated and non-operated assets in NEPA, our position consists of average 88% working interest and 72% NRI on operated wells that yield 100% lean natural gas. We enjoy a significant non-operated position in NEPA. In addition, we have approximately 27 new well locations for near-term development in NEPA.

We are the eighth largest producer in NEPA, on a gross operated production basis. During the years ended December 31, 2022 and 2021, we produced 50.8 Bcf (or an average of 139.2 MMcf/d) and 56.1 Bcf (or an average of 153.7 MMcf/d), respectively, from our NEPA properties, including both operated and non-operated wells. We did not drill any new wells in NEPA in 2021. During the year ended December 31, 2022, we drilled five wells in NEPA. However, we utilized a combination of compression projects and drilled but uncompleted (DUC) well completions to slow production declines and optimize production.

The image below reflects our NEPA acreage (Green), which spans the northeast portion of Pennsylvania and is comprised of both operated and non-operated assets, with the arrows indicating the direction of flow to existing markets and identifying the respective third parties with which BKV has secured downstream capacities. Our downstream transportation has the flexibility to move West and South into gulf coast markets via the Tennessee Gas Pipeline as well as into the northeast corridor via the Millenium pipeline while also maintaining intra-basin optionality.

Our Technology-Enabled Business

Our integrated business model allows us to develop, test and deploy new technologies to drive efficiencies across the business and to reduce our own emissions. We leverage technology in two important ways: we utilize our Data Lake and in-house data science team to drive efficiencies and insights across the business and we utilize probabilistic modeling approaches and advance risk management techniques to enhance our decision-making abilities, particularly with regards to potential acquisitions. We employ a technology-focused approach, such as utilization of our proprietary instrument air packages, satellite and perimeter pad emissions monitoring, and advanced production and emissions measurement, to enable methane measurement and mitigation, and emission elimination strategies, that reduce CO_2e emissions across our operations.

Our operations in the Barnett and NEPA have been increasingly automated through a program called “Autotune,” which is an effort to optimize and automate plunger lift systems to increase production through autonomous dynamic tuning of plunger control inputs. This Autotune method utilizes computer algorithms which toggle and optimize various input and control variables for plunger lift systems to increase production time for an average well as compared to a baseline (based on a manual method of managing plunger input and control variables).

We have implemented our “Pad of the Future” program in our upstream business, with the objectives of converting natural gas-powered instrument pneumatics to compressed air-powered functionality on existing pads, significantly reducing our GHG emissions and improving pad efficiencies and economics. In addition, we have implemented emissions surveys, an advanced four-tiered emissions monitoring and mitigation strategy utilizing specialized surveillance technology. We have obtained permits for 2.5 MW of commercial solar power, with plans to install up to 5 MW of commercial solar power within the next three years to offset our Scope 2 emissions from our electricity usage in our upstream operations.

In 2021, we certified our entire NEPA production and, in 2022, we certified a portion of our Barnett production and, in each case, achieved a Gold rating with Project Canary’s TrustWell environmental assessment (Project Canary is an environmental certification and ESG data company). This is the second highest rating a company can receive for its production, qualifying our NEPA natural gas production as RSG, which we believe could command a premium in the marketplace. Through RSG production, we provide reliable and affordable energy, while actively participating in the energy transition.

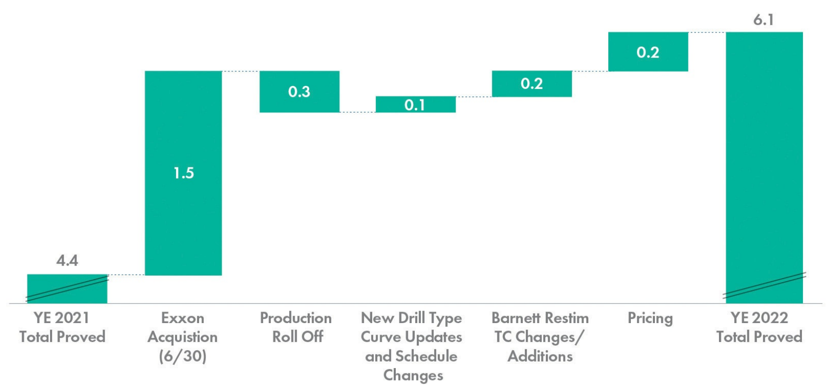
Our Reserves

The following summarizes our natural gas and oil properties as of December 31, 2022 and our average net daily production for the year ended December 31, 2022, including the properties we acquired in the Exxon Barnett Acquisition.

	December 31, 2022							
	Estimated Total Proved Reserves							
Operating Region	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Oil (MBbls)	Total (MMcfe)	Average Net Daily Production (MMcfe/d)[(1)]	Average Reserve Life (years)	Producing Wells	Net Acres
Barnett	3,955,331	211,500	1,868	5,235,544	732.7	19.6	6,825	457,787
NEPA	900,346	—	—	900,346	139.2	17.7	397	36,886
Total	4,855,676	211,500	1,868	6,135,890	871.9	19.3	7,222	494,673

(1) The production rate for the properties acquired in the Exxon Barnett Acquisition was based on management's review of the historical accounting information with respect to such assets.

YE21 to YE22 Proved Reserves Variance (TCFE)



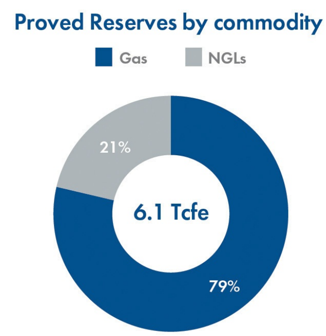
Based on forecasts used in our reserve reports, our PDP reserves as of December 31, 2022 had estimated average five-year and ten-year annual decline rates of approximately 8.7% and 7.3%. As a result of this overall low decline profile of our natural gas and oil assets, coupled with refrac opportunities that are capital efficient projects, we are able to maintain flat production year over year with relatively low reinvestment rate. We believe the combination of our high margin profile and our conservative reinvestment rate approach, supported by our low decline reserves, will allow us to generate significant Adjusted Free Cash Flow to (i) deliver stockholder returns and (ii) opportunistically fund value accretive growth opportunities.

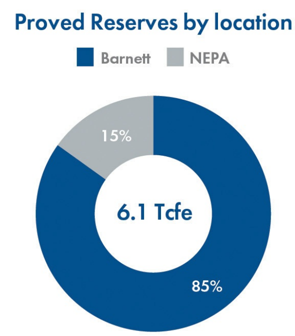
The following table illustrates the weighted average decline profiles and total production in the year ended December 31, 2022 associated with our proved reserves as of December 31, 2022:

	December 31, 2022					
					Weighted Average Annual PDP Decline(1)	
Operating Region	Estimated Total Proved Reserves (MMcfe)	% Natural Gas	% Natural Gas Liquids	% Oil	Five Year	Ten Year
Barnett	5,235.5	75.5%	24.2%	0.2%	7.8%	6.7%
NEPA	900.3	100%	—	—	13.5%	10.3%
Total	6,135.9	79.1%	20.7%	0.2%	8.7%	7.3%

(1) Reflects the estimated average year over year decline rates of our base reserves as of December 31, 2022 for the five-year period ending December 31, 2027 and the ten-year period ending December 31, 2032, in each case based on the forecasts used in estimating our proved reserves.

The following table summarizes our proved reserves by commodity and proved reserves by location at December 31, 2022:





The following table illustrates the weighted average decline profiles and total production in 2021 associated with our proved reserves as of December 31, 2021:

	December 31, 2021					
					Weighted Average Annual PDP Decline(1)	
Operating Region	Estimated Total Proved Reserves (MMcfe)	% Natural Gas	% Natural Gas Liquids	% Oil	Five Year	Ten Year
Barnett	3,496,235	71.5%	28.3%	0.2%	7.0%	6.3%
NEPA	945,528	100%	—	—	12.4%	9.9%
Total	4,441,763	77.6%	22.3%	0.1%	8.3%	7.2%

(1) Reflects the estimated average year over year decline rates of our base reserves as of December 31, 2021 for the five-year period ending January 31, 2026 and the ten-year period ending January 31, 2031, in each case based on the forecasts used in estimating our proved reserves.

Our Acreage

The following table summarizes our acreage position as of December 31, 2022:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett[1]	638,099	418,919	41,625	38,868	679,725	457,787
NEPA	62,191	28,162	20,823	8,723	83,015	36,886
Total	700,290	447,081	62,449	47,591	762,740	494,673

The following table summarizes our acreage position as of December 31, 2021:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett[1]	453,584	261,810	32,120	30,771	485,704	292,582
NEPA	61,971	28,162	20,890	8,816	82,862	36,978
Total	515,555	289,973	53,010	39,587	568,566	329,560

(1) Includes acreage acquired during 2021 from Jamestown Resources, L.L.C., Larchmont Resources, L.L.C., and Pelican Energy, L.L.C., for which acreage the leasehold interest is derived from unit-based assignments and includes 133,470.22 gross and 3,317.69 net developed acres, and no undeveloped acreage.

The percentage of our net undeveloped acreage that is subject to lease expiration over the next three years, if such leases are not renewed, is approximately 2.55% in 2023, 0.39% in 2024 and 1.48% in 2025.

Our Productive Wells

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2022:

	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Barnett	5,822	5,597	9	9	5,831	5,606	96.1%
NEPA	142	126	—	—	142	1262	88.9%
Total	5,964	5,724	9	9	5,973	5,733	96.0%
Non-operated Wells:							
Barnett	1,122	95	22	0.1	1,144	96	9.9%
NEPA	266	36	—	—	266	36	14.3%
Total	1,388	132	22	.1	1,410	132	10.8%
Total Wells:							
Barnett	6,944	5,693	31	9	6,975	5,702	83.9%
NEPA	408	163	—	—	408	163	41.0%
Total	7,352	5,855	31	9	7,383	5,864	81.5%

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2021:

	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Operated Wells:							
Barnett	3,950	3,170	8	6	3,958	3,177	97.8%
NEPA	138	101	—	—	138	101	88.9%
Total	4,088	3,272	8	6	4,096	3,279	
Non-operated Wells:							
Barnett	838	672	8	6	846	679	3.5%
NEPA	256	189	—	—	256	189	13.9%
Total	1094	861	8	6	1102	868	
Total Wells:							
Barnett	4,788	3,843	16	12	4,804	3,856	81.2%
NEPA	394	291	—	—	394	291	39.9 %
Total	5,182	4,134	16	12	5,198	4,147	

Drilling, Refrac and Restimulation Activity

During the years ended December 31, 2021 and 2020, we did not have an active drilling rig running in any of our operated properties, and therefore we did not drill any wells on these properties. During this period, we completed a total of six wells that were previously drilled but uncompleted wells in NEPA. During the year ended December 31, 2022, we drilled five wells in NEPA and eleven wells in the Barnett, each of which constitutes a gross operated well and net operated development well. During the year ended December 31, 2022, eleven wells were completed in the Barnett and six wells were completed in NEPA all of which were net productive.

In November 2020, we began a restimulation program in the Barnett to develop economic incremental reserves in existing wellbores and arrest the overall field production decline. In 2021, we led the industry in number of executed horizontal restimulations by completing 213, according to public completion reports. Additionally, as of December 31, 2022, we had 167 proved undeveloped, 147 probable undeveloped and 82 possible horizontal locations and 584 proved developed non-producing, 743 probable and 234 possible horizontal refrac candidates in the Barnett, including those acquired in the Exxon Barnett Acquisition.

Sales Volumes and Unit Prices

The following table summarizes sales volumes, sales prices and production cost information for our net natural gas and production for the years ended December 31, 2022, 2021 and 2020.

	Year Ended December 31,		
	2022	2021	2020
Sales Volumes			
Barnett:			
Natural gas (MMcf)	166,771.0	129,960.0	34,879.1
Natural gas liquids (MBbl)	10,187.0	9,829.3	2,565.2
Oil (MBbl)	140.0	123.0	28.6
Total Barnett (Bcfe)	228.7	190.1	50.4

	Year Ended December 31,		
	2022	2021	2020
NEPA:			
Natural gas (MMcf)	50,814	56,095.1	61,279.9
Natural gas liquids (MBbl)	—	—	—
Oil (MBbl)	—	—	—
Total NEPA (Bcfe)	50.8	56.1	61.3
Total Company (Bcfe)	279.6	245.8	111.7
Average Sales Prices (excluding impact of derivative settlements)			
Barnett:			
Natural gas (per Mcf)	$ 6.38	$ 3.58	$ 1.62
Natural gas liquids (per Bbl)	$ 30.58	$ 22.90	$ 4.66
Oil (per Bbl)	$ 84.76	$ 61.46	$ 46.67
NEPA:			
Natural gas (per Mcf)	$ 4.85	$ 2.34	$ 0.74
Natural gas liquids (per Bbl)	$ —	$ —	$ —
Oil (per Bbl)	$ —	$ —	$ —
Total Company (per Mcfe)	$ 5.84	$ 3.38	$ 1.03
Average Sales Prices (including impact of derivative settlements)[1]			
Natural gas (per Mcf)	$ 3.72	$ 2.40	$ 1.87
Natural gas liquids (per Bbl)	$ 27.78	$ 16.76	$ 12.57
Oil (per Bbl)	$ 84.76	$ 61.46	$ 31.07
Total Company (per Mcfe)	$ 3.95	$ 2.52	$ 1.90
Average Production Cost (per Mcfe)[2]			
Barnett	$ 1.43	$ 1.31	$ 0.36
NEPA	$ 0.26	$ 0.23	$ 0.22
Total Company	$ 1.69	$ 1.06	$ 0.28

(1) Impact of derivatives prices excludes $158.3 million of derivative contract terminations in 2022.

(2) Excludes natural gas and oil ad valorem and production taxes.

Base Production Optimization

We seek to be a leader in safe, efficient and accretive base production management. We are highly focused on flattening decline while minimizing costs all while reducing our environmental footprint. Automation and optimization play a pivotal role in this focused approach. Our plunger automation program, *i.e.*, "Autotune," improves the efficiency of our plunger lift systems, resulting in up to 2% improvement in production. Initiatives like automated equipment actuation and automated water call outs serve to minimize response times and reduce manpower requirements. BKV operates a steady and robust workover program, constantly reviewing candidate wells and maintaining a queue of prioritized jobs that provide economic and accretive production uplift. We operate a fleet of over 700 gas lift and wellhead compression units with real time optimization of this fleet. Ensuring our compressors are optimized for each specific facility allows us to maximize production and reduce costs. Other elements of our base management excellence include automated data collection and analysis processes, including well reviews, surveillance dashboards, and process change alerts. Additionally, we monitor and mitigate pipeline pressures, evaluate and implement compression and pressure reduction projects jointly with our midstream partners. We seek to prudently manage and lower operating costs through, for example, purchasing and operating our own slickline units, bringing various maintenance activities in-house which are traditionally third party, negotiating and signing longer term supply and vendor contracts, establishing strategic and advantageous procurement partnerships, leveraging basin scale to achieve organizational and purchasing efficiencies, and maintaining an efficient organizational structure with high performing teams.

Natural Gas Midstream

Our natural gas midstream operations support our upstream assets as well as generate incremental revenue via gathering, processing and transportation of third-party production. In the Barnett, we have extensive infrastructure with capacity across the field and limited additional capital required to connect our wells. Our midstream system in the Barnett operates at low pressure with only approximately 50% utilization as of December 31, 2022. In the Barnett, as of December 31, 2022, approximately 190 MMcf/d of our gross production volumes (approximately 23% of our total gross Barnett production) were gathered and processed by our owned Barnett midstream system, with our remaining Barnett production primarily under an agreement with EnLink with no minimum volume commitments. Our owned Barnett midstream system includes approximately 778 miles of gathering pipeline, 65 gas compression units and one amine processing unit.

In NEPA, as of December 31, 2022, our gross operated production volumes were approximately 162 MMcf/d. The volumes flow into third-party gatherers in the following proportions:

- UGI Energy Services Midstream Services (“UGI”): 57%
- Williams Companies (“Williams”): 35%
- Energy Transfer LP (“Energy Transfer”): 8%

Our owned NEPA midstream system includes approximately 16 miles of gas gathering pipelines, 14 miles of freshwater distribution pipelines and six gas compression units. We also have a 29.4% non-operated ownership interest in a Repsol operated midstream system with over 100 miles of gathering pipelines with 450 MMcf/d of capacity and a compression station with approximately 14,000 horsepower. Repsol owns the remaining 70.6% of the system, which has a current throughput of approximately 174 MMcf/d and services both system owner gas and third-party gas.

Gas Gathering & Processing Agreements

The majority of our gross operated production volumes in NEPA are contractually further gathered and treated by three main third parties. As of December 31, 2022, approximately 57%, 35% and 8% of our gross operated volumes in NEPA were further gathered and treated on UGI, Williams and Energy Transfer gathering systems, respectively. We have secured these services through acreage dedications, pursuant to which current and future production sourced from the specific acreage positions designated in each contract is required to be gathered and treated by each specific entity. Some of our NEPA gas gathering and processing contracts contain limited minimum volume commitment terms (“MVCs”), the earliest of which expire in the first quarter of 2025 and the second quarter of 2029. As of December 31, 2022, such MVCs require us to deliver 36 MMcf/d of natural gas, a majority of which flows into 95 MMcf/d of MVC related the gathering, central delivery point aggregation and intra-basin transport, which currently represents 59% of the gross volumes produced from covered acreage. Overall, the acreage dedication approach, coupled with limited MVCs, provides us strategic flexibility while also securing access to gathering, processing and transportation services. The use of third parties to contractually perform gathering and treating services also negates capital spending requirements for these services and allows us to focus our efforts and capital spend on our core energy and production business.

The terms of these contracts range from 10 and 20 years from original execution date, with an average term of seven years remaining between the various contracts, as of December 31, 2022. The specified rates within these contracts are generally escalated annually subject to a standard Consumer Price Index escalator. These gathering and treating contracts offer deliverability to intra-basin markets, as well as multiple downstream pipelines that offer access to inter and intra-regional markets. This flexibility ultimately provides sufficient liquidity and market optionality that help facilitate the overall process of maximizing corporate netbacks.

For the assets we acquired in the Devon Barnett Acquisition, approximately 99% of our natural gas is gathered and transported by EnLink through various contracts that govern the services provided for the

Bridgeport, Ponder and Jarvis systems. The Bridgeport system consists of both rich and lean gas governed by a market-rate based contract, as amended, with a term expiring in 2033. The gathering and processing fees under the Bridgeport contract contain an incentive mechanism pursuant to which we can achieve lower rates through refractured or new wells. All NGLs under the Bridgeport contract are sold to EnLink at Mont Belvieu pricing subject to a market-based transport and fractionation differential. There are no MVCs associated with the natural gas gathering agreements for the assets we acquired in the Devon Barnett Acquisition.

For the assets we acquired in the Exxon Barnett Acquisition, approximately 90% of our natural gas is gathered and transported through an agreement assigned to our subsidiary, BKV Midstream, through various market-rate based contracts that take lean gas to various delivery points into Energy Transfer's pipeline. All gas currently flows to Energy Transfer, where BKV is under an acreage dedication for its downstream takeaway. We have one MVC related to the assets acquired in the Exxon Barnett Acquisition for less than $1.0 million per year, which MVC is currently unfulfilled and results in immaterial unutilized gathering charges. However, produced gas that can currently flow through this contract and fulfill the MVC has been rerouted and now flows through BKV's (formerly XTO Energy, Inc.'s) owned and operated gathering and compression facilities. The decision to construct the facilities, reroute this gas and strand the MVC-based contract was based upon superior economics and results in lower overall gathering and compression fees, even with the inclusion of the unutilized gathering charges. The MVC-based contract expires in the third quarter of 2024.

Power Generation

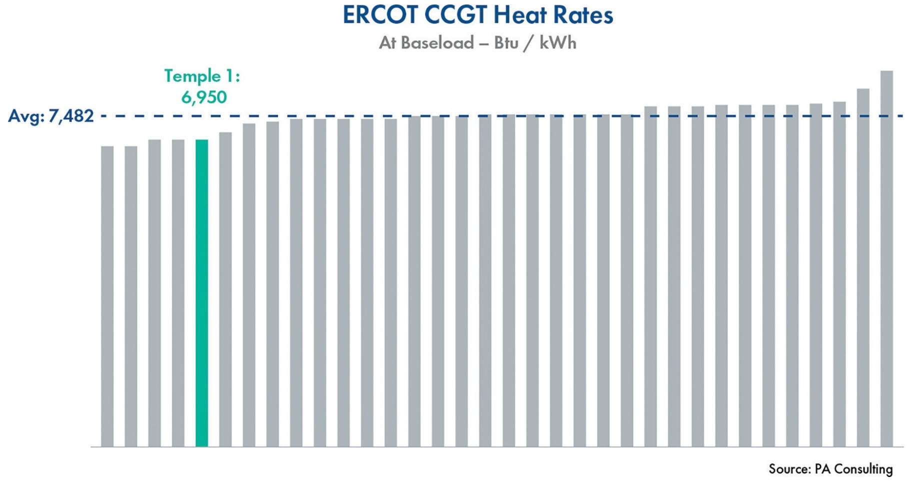
We have a 50% ownership interest in the BKV-BPP Power Joint Venture, which owns Temple I, a newly-constructed, modern combined cycle gas and steam turbine power plant located in the ERCOT North Zone in Temple, Texas. The remaining 50% interest is owned by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu.

Temple I's power generation output is sold into the competitive wholesale bulk power market managed by ERCOT, Texas' electrical grid operator. ERCOT currently provides electric power to approximately 23 million people in Texas, with its customers using about 85% of the state's electric power. The operating flexibility of the power plant provides significant competitive advantages in the ERCOT market. Temple I can generate and supply the power needs of approximately 750,000 households in central Texas.

Operational since July 2014, Temple I's modern technology enables it to respond to rapidly changing market signals in real time, making it well-suited to serve the various needs of the ERCOT market. Temple I has an average power generation capacity of 755 MW. Key equipment at Temple I includes Siemens natural gas combustion turbine generators and steam turbine generators, as well as Benson heat recovery steam generators. The electrical transmission interconnection at Knob Creek Substation ensures minimal congestion risk. Temple I typically undergoes seasonal maintenance outages in spring and fall to ensure the highest operational readiness during the time when electricity consumption peaks (in winter and summer).

Temple I remained online at full capability during the historic February 2021 Winter Storm Uri and has since implemented incremental upgrades. Temple I has invested over $840,000, with an additional $220,000 in planned expenditures for 2023, to construct winterization enclosures, add insulation, and install heat tracing systems and back-up generators to provide freeze protection around at-risk piping, equipment and instrumentation in the power plant and gas yard. In 2021, a wet compression system was installed to increase the power plant's output while operating in high ambient temperatures. The system allows a larger volume of air to be compressed before being fed into the combustion process along with natural gas, thus increasing generation capacity during summer, the time when the ERCOT market's power demand typically peaks. Temple I deploys modern CCGT technology, which combines the working process of gas combustion, turbine and steam turbine generation. It is one of the more flexible CCGTs supplying power to the ERCOT system due to its ability to achieve 50% production within 10 minutes and full baseload capacity within 30 minutes. Temple I is also among the most efficient generators supplying power to ERCOT, with a baseload design heat rate of approximately 6,950 Btu/kWh, which is well below the ERCOT CCGT average, as shown in the chart below. Equipped with pollution control management systems to maintain low emissions, the power plant's high efficiency and flexible operations helps maintain its competitive position in the ERCOT market.

The following chart summarizes Temple I’s realized heat rate as compared to other CCGT in ERCOT.



We expect our power generation assets will be synergistic with our base upstream business. In the near term, we will seek to establish midstream contracts that allow us to supply our own natural gas to Temple I and its firm intrastate natural gas storage service at the Bammel storage facility. Supplying our own natural gas to Temple I will reduce gas transportation costs and create reciprocal natural hedges for both businesses via vertical integration. Additionally, we leverage our existing organization to provide marketing, engineering, finance, accounting and other administrative services to the BKV-BPP Power Joint Venture for an annual fee plus expenses. In addition, after receiving the necessary approvals from the PUCT and ERCOT, the BKV-BPP Power Joint Venture recently launched a retail marketing business to sell electricity to commercial, industrial, and residential retail customers in Texas through its wholly owned subsidiary, BKV-BPP Retail, under the brand name BKV Energy. Since its official launch in February 2023, BKV Energy has built a portfolio of over 5,200 customers and is licensed to serve throughout the deregulated portions of Texas. We intend to develop our ability to provide a Scope 1, 2 and 3 carbon neutral gas product, which we refer to as MNZ gas, and we believe that the expansion of our presence in the retail power space, along with the synergistic and opportunistic growth of our upstream, midstream and power generation businesses, will provide our retail energy business the opportunity to offer end consumers household energy sourced from MNZ gas. For more information about the risks involved in our retail power business and efforts to market MNZ gas, see “*Risk Factors — Risks Related to Our Power Generation Business — Our long-term business plan involves the expansion of our retail power business and the development of opportunities to offer end consumers household energy sourced from a Scope 1, 2 and 3 carbon neutral gas product*.”

In addition to 75,000 MMBtu/d of firm transportation services with Energy Transfer and its subsidiaries, Temple I’s Bammel storage contract with Energy Transfer provides Temple I up to 2.8 Bcf of natural gas storage capacity, providing daily gas supply operating flexibility. The firm transportation and storage contracts with Energy Transfer and its subsidiaries also grant BKV-BPP Power the option to purchase and store in reserve excess natural gas, which can be released at times when gas prices are potentially higher, such as during seasonal price cycles or times of scarcity. Moreover, the potential to utilize our midstream assets to deliver and optimize natural gas feedstock to the power plant and to expand our CCUS business by sequestering post combustion CO_2 from the power plant are additional vertical integration opportunities that we intend to explore over time.

In addition, in connection with our goal to provide our retail energy business the opportunity to offer end consumers household energy sourced from MNZ gas, we are working with Project Canary, an environmental certification and ESG data company, to assess future development of emissions monitoring for the gas supply and combined-cycle electric production at Temple I and to explore the potential ability to certify reliability and low emissions from wellhead to electron. Furthermore, we believe there is significant opportunity from integrated retail gas and power offerings directly to end-user customers and we are in the process of building this capability for the future. We believe we can create a differentiated offering to strategic buyers, retail and industrial customers. For more information about the risks involved in our retail power business and efforts to market MNZ gas, see "*Risk Factors — Risks Related to Our Power Generation Business — Our long-term business plan involves the expansion of our retail power business and the development of opportunities to offer end consumers household energy sourced from a Scope 1, 2 and 3 carbon neutral gas product*."

BKV-BPP Power Limited Liability Company Agreement

Temple I is owned by Temple Generation Intermediate Holdings II, LLC, which is owned 100% by BKV-BPP Power, which, in turn, is owned 50% by us and 50% by BPPUS, a wholly owned subsidiary of Banpu Power. See "*— Our Relationship with Banpu*" and "*Certain Relationships and Related Party Transactions*."

We and BPPUS are each a party to the BKV-BPP Power LLC Agreement governing the BKV-BPP Power Joint Venture, which, among other things, provides that a general manager appointed by the BKV-BPP board will have the power to manage and administer the business and affairs of BKV-BPP Power, subject to specified matters reserved for approval by the BKV-BPP board. The appointment and removal of the general manager must be approved by both the BKV-BPP board and BPPUS. Transfer or encumbrance of a party's interest in BKV-BPP Power is permitted without prior approval of the other party or the BKV-BPP board. However, no transfer will be permitted if the transfer: (A) would subject BKV-BPP Power to U.S. federal securities law reporting requirements, (B) would cause BKV-BPP Power to lose its status as a U.S. partnership for federal income tax purposes or will cause BKV-BPP Power to be classified as a "publicly traded partnership," (C) would violate, give rise to a default under or cause any payment to become due under any credit agreement, guaranty, or similar credit document or any other material contract to which BKV-BPP Power or any affiliate is bound, or (D) occurs prior to the repayment by BKV-BPP Power of all loans and other amounts outstanding under the term loans.

In the event that either party admits in writing that it is unable to perform its obligations (including any obligation to provide additional capital contributions) under the BKV-BPP Power LLC Agreement, the non-defaulting party will be entitled to (i) sell the assets of the joint venture and dissolve the joint venture on reasonable terms deemed acceptable to the BKV-BPP board, (ii) obtain specific performance of the non-defaulting party's obligations, and/or (iii) exercise any other right or remedy provided in law or in equity. The BKV-BPP board will determine the amount and timing of distributions of operating cash flow (which will be done no less frequently than once per quarter) and net capital proceeds (which will be distributed within three business days after becoming available for distribution). All distributions will be made on a pro-rata basis to us and BPPUS. As of December 31, 2022, no distributions have been made by BKV-BPP Power. Additional cash capital contributions will be required to be made by us and by BPPUS on a pro-rata basis upon 30 days written notice either by us or by BPPUS; provided that the additional contributions must be expended on items included in the annual approved budget, items in response to an emergency in the event that BKV-BPP Power does not have sufficient cash reserves to address such emergency, or any other matter approved by the BKV-BPP board. Otherwise, neither us nor BPPUS will be required to provide additional capital contributions without consent.

Major decisions and significant activities of BKV-BPP Power are reserved for approval by at least a majority of the members of the BKV-BPP board, such as, among other things, any merger, consolidation, amalgamation, conversion of BKV-BPP or any of its subsidiaries, into another form or entity or other business combination of any nature, wind up, the dissolution, liquidation, commencement or any filing or petition for a voluntary bankruptcy, reorganization, debt arrangement involving BKV-BPP Power, any plan to or initial sale of BKV-BPP Power or other equity interests to the public, any amendments, restatements or revocations of its organizational documents, execution, amendment or termination of a material contract, and any amendment to or deviation from the dividend policy of the joint venture or any of its subsidiaries. Under the terms of the BKV-BPP Power LLC Agreement:

- we do not have the power to unilaterally cause BKV-BPP Power to make distributions;
- we may be required to make additional capital contributions to fund items approved in the annual budget or other matters approved by the board of BKV-BPP Power at the request of BPPUS, which

would reduce the amount of cash otherwise available for dividend payments by us on our common stock or require us to incur additional indebtedness; and

- BKV-BPP Power may incur additional indebtedness in an amount greater than $1,500,000 if approved by the board of BKV-BPP Power, which debt payments would reduce the amount of cash that might otherwise be available for distributions to us.

Carbon Capture, Utilization and Sequestration

Through our CCUS business, we aim to reduce man-made GHG emissions to the atmosphere by capturing CO_2 emitted in connection with natural gas activities, whether from our own operations or third-party operations, as well as from other energy and industrial sources. Our process involves capturing CO_2 before it is released into the atmosphere and then compressing the captured CO_2 and transporting it via pipeline to sites where it can be injected into UIC wells for secure geologic sequestration. Additionally, we have engaged Project Canary to measure, analyze and report the environmental attributes of the sequestration projects. Although we formally launched our CCUS business in March 2022 with the establishment of BKV dCarbon Ventures, we have been evaluating project opportunities and developing our CCUS business for approximately two years. The development of our CCUS business has progressed rapidly, supported by internal engineering, business development and regulatory professionals, along with academics and CCUS-focused partnerships. We believe that with a continued and timely execution of our business plans, and the receipt of external funding in 2023, we will begin generating positive CCUS net income via tax credits and other tax benefits in 2025. We expect to fund our CCUS business with a combination of cash flows from operations and funding from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified and described below.

We seek to execute CCUS projects with attractive standalone economics for high, medium and low CO_2 concentration streams that will sequester emissions from both our own operations and from third-party operations. As part of our "closed-loop" approach to our net zero emissions goal, we expect to apply the CO_2 emissions that are sequestered through our CCUS business to offset GHG emissions from our owned and operated upstream businesses. As a result, we expect our CCUS business to contribute to our goals to fully offset the Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025, and the Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s. We estimate that our owned and operated upstream Scope 1 and 2 annual emissions were approximately 1.7 Mtpy CO_2e as of December 31, 2022 and that our owned and operated upstream Scope 1, 2 and 3 annual emissions were approximately 15.32 Mtpy CO_2e as of December 31, 2022. See "—*Path to Net Zero Emissions*" below for a description of how we estimate our Scope 1, 2 and 3 annual emissions and how we expect our CCUS business to contribute to the offset of those emissions.

In August 2022, we entered into a development agreement with Verde CO2, an independent carbon capture and sequestration developer and operator, to identify, evaluate and develop additional CCUS projects throughout the United States. We believe our agreement with Verde CO2 will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration. As of April 6, 2023, we have paid $17.3 million to Verde CO2 under the development agreement. We currently expect to invest up to $250.0 million over the next three years to fund efforts by BKVerde, a subsidiary of BKV dCarbon Ventures, to efficiently identify and evaluate feasible CCUS projects, and to execute on those projects.

Currently, we are pursuing twelve potential CCUS projects that we believe are commercially viable based on economics supported by enhanced Section 45Q tax credits and can be completed by the early 2030s. We anticipate that the completion of these or a combination of other comparable projects would enable us to achieve our Scope 1, 2 and 3 emissions goals. These twelve potential CCUS projects consist of a combination of projects being developed by BKV's internal CCUS team and projects being developed by Verde CO2. Under our development agreement with Verde CO2, Verde CO2 will develop and present projects to us for acceptance and assignment to BKVerde; however, we cannot guarantee that all projects currently in development by Verde CO2 will be accepted and assigned to BKVerde. See "— *Recent*

Developments — CCUS Project Development with Verde CO2." Our projected timeline for commercial operations of these twelve projects by the early 2030s depends in part on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. Our timeline also depends on a regulatory environment that is favorable to our projects and their development. These twelve potential projects can be placed into four categories: (i) those that have reached FID, (ii) near-term NGP projects, (iii) near-term industrial projects, and (iv) projects under evaluation. Near-term projects are those that we anticipate will reach FID in either 2023 or 2024. We have achieved notable milestones with respect to several of the projects within the four categories, as more fully described below.

FID Projects

- We have reached FID and entered into definitive agreements with respect to the Barnett Zero Project, and we have reached internal FID for the Cotton Cove Project. These two projects have a combined forecasted annual sequestration volume of approximately 255,000 metric tons per year of captured CO_2e by the end of 2024.

Barnett Zero Project. In June 2022, we reached FID and entered into a definitive agreement in connection with our first high concentration CCUS project in the Barnett with EnLink. This CCUS project, which we refer to as the Barnett Zero Project, will separate CO_2 from substantially all of our EnLink-gathered natural gas production. In the Barnett Zero Project, EnLink will transport our natural gas produced in the Barnett to its natural gas processing plant in Bridgeport, Texas, where the CO_2 waste stream will be captured, compressed and then disposed of and sequestered via our nearby injection well. We expect the Barnett Zero Project to achieve an average sequestration rate of up to approximately 210,000 metric tons of CO_2e per year, with the first injection expected by December 2023. Following commencement of commercial operations of our project with EnLink, we intend to use this project as a prototype for modular NGP projects that can be repeated and quickly scaled.

Cotton Cove Project. On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of, and geologically sequester CO_2 generated as a byproduct of our natural gas production in the Barnett and will utilize our newly acquired BKV Midstream assets to do so. We have multiple company-owned pore space opportunities for CO_2 injection, and we estimate the Cotton Cove Project will geologically sequester up to approximately 45,000 metric tons of CO_2e per year. We currently estimate the total investment required by us for the Cotton Cove Project to be between approximately \$14.0 and \$24.0 million. We are targeting commencement of CO_2 sequestration activities by the first half of 2024, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects.

We are also seeking to expand the Barnett Zero and Cotton Cove Projects to pilot, and then scale, post-combustion carbon capture technology that would allow us to sequester up to an additional approximately 250,000 metric tons per year of captured CO_2e from low concentration emissions from within our BKV Midstream and/or EnLink's Bridgeport processing operations. As part of this process, we intend to utilize compressor waste heat to reduce energy requirements and cost.

NGP Projects

In addition to the Barnett Zero Project and the Cotton Cove Project, we have identified three potential NGP projects to sequester third-party emissions, which we expect to reach FID in either 2023 or 2024. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of at least approximately 970,000 metric tons per year of captured CO_2e.

A significant portion of the carbon capture infrastructure necessary to execute these potential NGP projects already exists, one of which is currently being developed by Verde CO2 under our development agreement with them. For another one of these projects, we have entered into a non-binding letter of intent to secure a pore space leasehold that would provide approximately 45 million metric tons of CO_2e sequestration capacity. Therefore, if approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2025. We expect that by the end of 2025, these three NGP projects will have initial individual annual sequestration volumes of approximately 70,000, 265,000 and 635,000 metric tons per year of captured CO_2e, respectively, and a combined annual aggregate sequestration volume of approximately 970,000 metric tons per year of captured CO_2e. In addition, we expect over time to submit permit applications to develop Class VI injection wells in order to expand the sequestration capacity of two of these NGP projects to gradually build up to a forecasted annual sequestration volume after 2025 for all three of these NGP projects of approximately 3.3 million metric tons per year of captured CO_2e.

We expect by the end of 2025 that the combined annual forecasted sequestration volume from these NGP projects, the Barnett Zero Project and the Cotton Cove Project (collectively having an annual forecasted sequestration volume of approximately 1.23 Mtpy CO_2e), would be capable of offsetting annually more GHG emissions than our remaining Scope 1 and 2 annual emissions from our owned and operated upstream businesses after taking into account the expected GHG emissions reductions from our “Pad of the Future” program, reductions attributable to emissions monitoring and leak surveys and emissions offsets from the installation of solar power (such remaining emissions estimated to be approximately 0.70 Mtpy CO_2e). See “— *Path to Net Zero Emissions*.” However, we have not secured external financing, reached FID or entered into definitive agreements for any of these three additional NGP projects. We may not complete all or any of these three additional NGP projects, the Barnett Zero Project or the Cotton Cove Project by December 31, 2025, in which case, we may consider alternatives to offset our Scope 1 and Scope 2 owned and operated upstream emissions (including the purchase of verified offset credits) but, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses by the end of 2025 and Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s.

Industrial Projects

We are currently evaluating three potential medium to higher concentration industrial projects to sequester third-party emissions, which we anticipate will reach FID in either 2023 or 2024. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of approximately 16.7 million metric tons per year of captured CO_2e.

Two of the three projects are being developed by Verde CO2 under our development agreement with them. One of the three projects includes an agreement to acquire a carbon dioxide storage agreement covering approximately 20,000 acres of state-owned land and pore space leaseholds have been secured for the other two of these projects. We also anticipate that Class VI permit applications for each of these projects will be submitted during 2023. If each of these projects is approved at FID and we are able to secure sufficient external financing, and assuming definitive agreements are timely executed containing terms we believe are obtainable, we expect to initiate sequestration operations between 2025 and 2029.

Additional Projects

We are currently evaluating and have begun commercial discussions with respect to four additional CCUS projects that we anticipate may reach FID after 2024. If approved and implemented, these four projects would provide a combined forecasted annual sequestration volume of approximately 9.8 million metric tons per year of captured CO_2e.

If each of these projects is approved at FID and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect to begin sequestration operations between 2026 and 2029.

Our CCUS business of capturing and sequestering emissions from our operations and from operations of third parties is a critical component of our “closed-loop” approach to achieving our goal of net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s. We expect to continue to identify and evaluate additional CCUS projects and we believe that we will be able to complete a sufficient number of the above-described or other CCUS projects in order to meet our Scope 1, 2 and 3 emissions goals by the early 2030s. See “— *Path to Net Zero Emissions*” for a more detailed description of how we anticipate reaching our Scope 1, 2 and 3 emissions goals.

While the aggregate forecasted annual volume of CO_2e captured and sequestered from our twelve identified potential CCUS projects is approximately 30 million metric tons per year, which is more than our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream businesses, we do not anticipate achieving an aggregate yearly volume of sequestration of 30 million metric tons per year of captured CO_2e by the early 2030s. Furthermore, there can be no guarantee that we will be able to execute and complete any of the twelve identified CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2e sequestration to achieve our Scope 1, 2 and 3 emissions goals on the timelines we anticipate.

We estimate the aggregate investment required by us to fund a sufficient number of the identified potential CCUS projects in order to achieve our Scope 1, 2 and 3 emissions goals to be between approximately $1.3 billion and $1.8 billion over the next seven to ten years. We anticipate that some of these project costs will be borne by third-party investors in these projects, including emitters, landowners and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund the anticipated cost of these CCUS projects with a combination of cash flows from operations and up to 40% from external sources, which may include joint ventures, project-based equity partnerships and federal grants. We are able to moderate the capital required to fund our CCUS business, as our CCUS business model provides flexibility for us to selectively invest in only the sequestration component of a project or in the capture, transportation and sequestration components, depending on the scope of the project. Therefore, if sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline, which may result in an inability to achieve our Scope 1, 2 and 3 emissions goals on the timeline we anticipate.

Our CCUS business and all of our CCUS projects are in the early stages of development and while we have reached FID and entered into definitive agreements with respect to the Barnett Zero Project and reached internal FID for the Cotton Cove Project, we have not reached FID with respect to or entered into definitive agreements necessary to execute any of the other ten potential projects identified above. We may not be able to reach agreements on terms acceptable to us or achieve our projected timeline for commercial operations for these projects. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to secure external funding for up to 40% of the anticipated capital requirements for the potential projects that we have identified. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on certain financial and tax incentives provided by the U.S. federal government. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business*."

To help us achieve our goal of becoming a leader in CCUS, we established a steering committee that includes two engineers renowned for their work in the development of CCUS projects: Dr. Paitoon (P.T.) Tontiwachwuthikul (Professor of Industrial & Process Systems Engineering & Fellow, Canadian Academy of Engineering) and Dr. Malcolm A. Wilson (Program Director, CO_2 Management, Office of Energy & Environment (OEE), Adjunct Professor of Engineering and Graduate Studies). These individuals are professors at the University of Regina, a leading carbon capture research institution, and each has been engaged in CCUS for over 30 years.

For more information on our CCUS business, see "*— Our Operations — Carbon Capture, Utilization and Sequestration.*"

Summary of Our Reserve Estimates

Ryder Scott, our independent petroleum engineers, prepared estimates of our natural gas, NGL and oil reserves as of December 31, 2022, 2021 and 2020. These reserve estimates were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserve reporting using SEC Pricing (except for the table that provides our estimated reserves as of December 31, 2022 at "NYMEX strip pricing" using pricing based on NYMEX future prices as of market close on December 31, 2022). For more information about our reserve volumes and values, see "*— Preparation of Reserves Estimates and Internal Controls*" and Ryder Scott's summary reserve reports, which are filed as exhibits to the registration statement of which this prospectus forms a part.

The following table provides our estimated proved reserve, probable reserve and possible reserve information prepared by Ryder Scott as of December 31, 2022, 2021 and 2020 and PV-10 Value and the Standardized Measure for each period. The increase in our proved reserves and the PV-10 Value of those reserves as of December 31, 2022 as compared to December 31, 2021 is primarily due to the Exxon Barnett Acquisition, our refrac and restimulation program, adding NGL rich locations to the drilling program and the increase in natural gas prices used in preparing the December 31, 2022 reserve information. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. In addition, estimates of probable and possible reserves are inherently imprecise and are more uncertain than proved reserves but have not been adjusted for risk due to that uncertainty, and therefore they may not be comparable with each other and should not be summed either together or with estimates of proved reserves. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.*" For more information about our proved reserves, see "*— Preparation of Reserves Estimates and Internal Controls*" and Ryder Scott's summary reserve reports, which are filed as exhibits to the registration statement of which this prospectus forms a part.

Estimated Reserves at SEC Pricing[1]

	December 31,		
	2022	2021	2020
Estimated proved developed reserves:			
Natural gas (MMcf)	3,798,019	2,494,926	1,893,161
Producing	3,468,896	2,346,712	1,893,161
Non-producing	329,123	148,214	—
Natural gas liquids (MBbls)	170,840	151,433	107,234
Producing	157,585	142,961	107,234
Non-producing	13,255	8,472	—
Oil (MBbls)	1,111	867	723
Producing	1,111	876	723
Non-producing	—	—	—
Total estimated proved developed reserves (MMcfe)	4,829,725	3,408,723	2,540,901
Producing	4,421,072	3,209,679	2,540,901
Non-producing	408,653	199,044	—
Standardized Measure (millions)	$ 5,809	$ 2,119	$ 504
PV-10 (millions)[2][3]	$ 7,389	$ 2,672	$ 552
Estimated proved undeveloped reserves:			
Natural gas (MMcf)	1,057,657	950,359	92,373
Natural gas liquids (MBbls)	40,660	13,722	—
Oil (MBbls)	758	58	—
Total estimated proved undeveloped reserves (MMcfe)[4][5]	1,306,165	1,033,040	92,373
Standardized Measure (millions)	$ 1,185	$ 294	$ 6
PV-10 (millions)[2][6]	$ 1,566	$ 403	$ 9

	December 31, 2022	2021	2020
Estimated total proved reserves:			
Natural gas (MMcf)	4,855,676	3,445,285	1,985,534
Natural gas liquids (MBbls)	211,500	165,155	107,234
Oil (MBbls)	1,869	925	723
Total estimated proved reserves (MMcfe)	6,135,890	4,441,763	2,633,274
Standardized Measure (millions)	$ 6,994	$ 2,413	$ 510
PV-10 (millions)(2)(7)	$ 8,955	$ 3,074	$ 561
Estimated probable developed reserves:			
Natural gas (MMcf)	367,081	—	—
Natural gas liquids (MBbls)	25,558	—	—
Oil (MBbls)	—	—	—
Total estimated proved undeveloped reserves (MMcfe)	520,430	—	—
Standardized Measure (millions)	$ 281	—	—
PV-10 (millions)(2)(9)	$ 372	—	—
Estimated probable undeveloped reserves:			
Natural gas (MMcf)	572,425	522,442	61,884
Natural gas liquids (MBbls)	39,319	31,227	—
Oil (MBbls)	1,556	486	—
Total estimated proved undeveloped reserves (MMcfe)	817,675	712,725	61,884
Standardized Measure (millions)	$ 420	$ 146	—
PV-10 (millions)(2)(10)	$ 563	$ 202	—
Estimated total probable reserves:			
Natural gas (MMcf)	939,506	522,442	61,884
Natural gas liquids (MBbls)	64,877	31,227	—
Oil (MBbls)	1,556	486	—
Total estimated proved undeveloped reserves (MMcfe)	1,338,105	712,725	61,884
Standardized Measure (millions)	$ 701	146	—
PV-10 (millions)(2)(11)	935	202	2
Estimated possible developed reserves:			
Natural gas (MMcf)	84,124	—	—
Natural gas liquids (MBbls)	8,146	—	—
Oil (MBbls)	—	—	—
Total estimated proved undeveloped reserves (MMcfe)	133,000	—	—
Standardized Measure (millions)	$ 53	—	—
PV-10 (millions)(2)(12)	$ 70	—	—
Estimated possible undeveloped reserves:			
Natural gas (MMcf)	540,878	381,941	—
Natural gas liquids (MBbls)	16,876	32,047	—
Oil (MBbls)	789	1,841	—
Total estimated proved undeveloped reserves (MMcfe)	646,868	585,269	—
Standardized Measure (millions)	$ 248	$ 51	—
PV-10 (millions)(2)(13)	$ 331	$ 75	—

	December 31, 2022	2021	2020
Estimated total possible reserves:			
Natural gas (MMcf)	625,002	381,941	—
Natural gas liquids (MBbls)	25,022	32,047	—
Oil (MBbls)	789	1,841	—
Total estimated proved undeveloped reserves (MMcfe)	779,868	585,269	—
Standardized Measure (millions)	$ 301	$ 51	—
PV-10 (millions)(2)(14)	$ 400	$ 75	—

(1) Prices for natural gas, oil and NGLs, respectively, used in preparing our estimated proved reserves and the associated PV-10 Value based on SEC Pricing (i) at December 31, 2022 were $6.358 per MMBtu (Henry Hub), $93.67 per Bbl (WTI Cushing) and pricing equal to 36.7% of WTI Cushing, (ii) at December 31, 2021 were $3.598 per MMBtu (Henry Hub), $66.56 per Bbl (WTI Cushing) and pricing equal to 39.5% of WTI Cushing and (iii) at December 31, 2020 were $1.985 per MMBtu (Henry Hub), $39.57 per Bbl (WTI Cushing) and pricing equal to 47% of WTI Cushing.

(2) PV-10 refers to the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. PV-10 is not a financial measure calculated in accordance with GAAP because it does not include the effects of income taxes on future net revenues. PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. Neither PV-10 nor Standardized Measure represent an estimate of the fair market value of our oil and natural gas properties. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and gas properties. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure reported in accordance with GAAP, but rather should be considered in addition to the Standardized Measure. See "*Prospectus Summary —Summary Reserve, Production and Operating Data*."

(3) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved developed reserves as of December 31, 2022, 2021 and 2020:

	December 31, 2022	2021	2020
PV-10 (millions)	$ 7,389	$2,672	$552
Present value of future income taxes discounted at 10%	(1,580)	(553)	(48)
Standardized Measure	$ 5,809	$2,119	$504

(4) Proved undeveloped reserves as of December 31, 2022 and 2021 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

(5) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our PUD, probable and possible reserves, which may cause us to decrease the amount of our PUD, probable and possible reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our PUD, probable and possible reserves to become uneconomic to develop, which would cause us to remove them from their respective reserve category.

(6) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved undeveloped reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$1,566	$ 403	$ 9
Present value of future income taxes discounted at 10%	(381)	(108)	(3)
Standardized Measure	$1,185	$ 294	$ 6

(7) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$ 8,955	$3,074	$561
Present value of future income taxes discounted at 10%	(1,961)	(661)	(51)
Standardized Measure	$ 6,994	$2,413	$510

(8) Estimates of probable and possible reserves, respectively, and the respective future cash flows related to such estimates, are inherently imprecise and are more uncertain than proved reserves, and the future cash flows related to such estimates. For more information regarding the presentation of probable and possible reserves, see "— *Preparation of Reserves Estimates and Internal Controls*."

(9) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated probable developed reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$372	$ —	$ —
Present value of future income taxes discounted at 10%	(91)	—	—
Standardized Measure	$281	$ —	$ —

(10) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated probable undeveloped reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$ 563	$202	$ —
Present value of future income taxes discounted at 10%	(143)	(56)	—
Standardized Measure	$ 420	$146	$ —

(11) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated probable reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$ 935	$202	$ —
Present value of future income taxes discounted at 10%	(234)	(56)	—
Standardized Measure	$ 701	$146	$ —

(12) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated possible developed reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$ 70	$ —	$ —
Present value of future income taxes discounted at 10%	(17)	—	—
Standardized Measure	$ 53	$ —	$ —

(13) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated possible undeveloped reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$330	$ 75	$ —
Present value of future income taxes discounted at 10%	(83)	(24)	—
Standardized Measure	$248	$ 51	$ —

(14) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated possible reserves as of December 31, 2022, 2021 and 2020:

	December 31,		
	2022	2021	2020
PV-10 (millions)	$ 400	$ 75	$ —
Present value of future income taxes discounted at 10%	(100)	(24)	—
Standardized Measure	$ 301	$ 51	$ —

During the years ended December 31, 2022 and 2021, we incurred costs of approximately $54.0 million and $7.2 million, respectively, to convert 74.0 Bcfe and 19.4 Bcfe, respectively, of proved undeveloped reserves to proved developed reserves. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2022 and 2021 are approximately $1,089.6 million and $578.3 million, respectively, over the next five years, substantially all of which we expect to finance through cash flow from operations. Our development programs in 2022 focused on refracturing under-stimulated wells and designing and drilling new wells in both our Barnett and Marcellus assets. All of our PUD reserves are scheduled to be developed within five years of their initial disclosure as PUDs. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.*"

In early 2023, natural gas commodity prices decreased significantly, and we expect this lower natural gas commodity pricing environment to continue at least into the second quarter of 2023. Due to our desire to be a prudent operator and exercise capital discipline in this pricing environment, in March 2023, we decreased our capital expenditures budget for development of natural gas properties for 2023 to $81.0 million from our original budget of $278.0 million, which was the amount applied in connection with the preparation of the estimates of our reserves as of December 31, 2022. We estimate that this reduction in 2023 capital expenditures would result in a decrease in our proved reserves, standardized measure value of proved reserves and the PV-10 value of proved reserves, as of December 31, 2022, by approximately 4.1%, 3.8% and 3.9%, respectively. If the current lower natural gas commodity pricing environment extends beyond 2023, we will continue to maintain capital discipline and reflect corresponding capital expenditure changes in our estimated reserves as of December 31, 2023. These changes would mainly impact proved undeveloped reserves and proved developed non-producing reserves, which collectively represent approximately 27.9% of our total estimated proved reserves as of December 31, 2022.

2022 Activity

During the year ended December 31, 2022, the Company's proved reserves increased by 1,694.1 Bcfe. The increase in proved reserves was primarily due to the acquisition of the 2022 Barnett Assets. Other factors that contributed to the increase in proved reserves during 2022 included increasing commodity pricing, which improved economics, improved recoveries due to the application of restimulation technology to producing wells and the addition of NGL rich locations to the drilling schedule. The Company produced 279.5 Bcfe during the year ended December 31, 2022.

Revisions of previous estimates consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 182.9 Bcfe as a result of higher average pricing during 2022 for natural gas, NGLs and oil. An additional upward revision of 52.0 Bcfe was made to proved developed reserves for performance adjustments. Upward revisions were offset by downward revisions to proved undeveloped reserves of 246.0 Bcfe relating to 76.0 gross (53.1 net) locations in the Marcellus and Barnett that were removed from the drilling schedule in exchange for locations with more favorable economics, as discussed in the following explanation of extensions and discoveries in 2022. Additional downward revisions of 67.3 and 42.9 Bcfe were made to proved undeveloped reserves related to performance and increased development costs, respectively.

Extensions and discoveries primarily consisted of the addition of 389.5 Bcfe from 71.0 gross (66.4 net) locations recognized as a result of our revised evaluation of properties acquired through our Devon Barnett Acquisition. The added locations are more rich in NGLs than the previously recognized locations that were removed from the 2021 drilling schedule, as discussed in the preceding explanation of revisions of previous estimates in 2022. Additional extensions consisted of proved undeveloped reserves of 85.8 Bcfe related to 27.0 gross (12.8 net) locations in NEPA and the Barnett that were recognized from acreage acquired in 2021 and as a result of the revised 2022 drilling plan. Extensions related to proved developed reserves of 74.1 Bcfe consisted of 23.0 gross (13.0 net) newly drilled wells on locations previously classified as unproved.

Purchases of minerals in place consisted of 1,237.1 Bcfe and 227.9 Bcfe of proved developed and proved undeveloped reserves, respectively, from the Exxon Barnett Acquisition. The acquired reserves consisted of operated working interests in 2,289.0 gross (1,696.4 net) wells and 53.0 gross (48.7 net) undeveloped locations.

Improved recoveries consisted of 80.5 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2022.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 73.9 Bcfe related to the completion of 19.0 gross (5.5 net) wells on proved undeveloped locations during the year ended December 31, 2022.

2021 Activity

During the year ended December 31, 2021, the Company’s proved reserves increased by 1,808.5 Bcfe. The increase in proved reserves was primarily due to increasing commodity pricing improving economics, and additions to the drilling schedule for both proved developed and undeveloped reserves. The Company produced 245.8 Bcfe during the year ended December 31, 2021.

Revisions of previous estimates primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 715.9 Bcfe and 245.6 Bcfe, respectively, as a result of higher average pricing during 2021 for natural gas, NGLs and oil. The remaining upward adjustment of 139.8 Bcfe relates to upward performance adjustments of 219.2 Bcfe to proved developed reserves offset by a downward revision of 79.4 Bcfe to proved developed reserves due to increased production costs.

Extensions and discoveries increased as a result of the completion of our evaluation of properties acquired through our Devon Barnett Acquisition, 550.1 Bcfe of proved undeveloped reserves was recognized for 123 gross (94.8 net) locations added to the Company’s revised drilling schedule during 2021. Additional extensions consisted of proved undeveloped reserves of 162.5 Bcfe related to 13.0 gross (9.6 net) locations in the Marcellus Basin recognized from acquired acreage and the revised 2021 drilling plan. Extensions related to proved developed reserves of 15.4 Bcfe consisted of 10.0 gross (3.0 net) newly drilled wells.

Purchases of minerals in place consisted of 17.7 Bcfe of proved developed reserves from the acquisition of additional working interests in 601.0 gross (14.6 net) wells and 1.8 Bcfe of proved undeveloped reserves from the acquisition of additional working interests in 18.0 gross (1.0 net) locations, each of which were in addition to the Company’s previously held working interests in wells or working interests in locations in the Barnett.

Improved recoveries consisted of 205.4 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2021.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 19.4 Bcfe related to the completion of 4.0 gross (3.9 net) wells on proved undeveloped locations during the year ended December 31, 2021.

2020 Activity

During the year ended December 31, 2020, the Company's proved reserves increased by 1,684.5 Bcfe. The increase in proved reserves was due to the Devon Barnett Acquisition offset by downward revisions primarily due to lower average pricing for natural gas during 2020.The Company produced 111.7 Bcfe during the year ended December 31, 2020.

Revisions of previous estimates of proved undeveloped reserves primarily consisted of a downward revision to proved undeveloped reserves of 146.7 Bcfe due to a combination of performance adjustments and lower average pricing of natural gas during 2020, and a downward revision of 186.5 Bcfe which removed locations due to lower average pricing of natural gas during 2020. Proved developed reserves were adjusted downward by 49.3 Bcfe due to lower average natural gas prices and performance.

There were no extensions and discoveries of proved developed or proved undeveloped reserves during the year ended December 31, 2020.

Purchases of minerals in place consisted of 2,178.7 Bcfe of proved developed reserves from the acquisition of 4,296.0 gross wells (3,867.5 net) from the Devon Barnett Acquisition.

Estimated Reserves at NYMEX Strip Pricing

The following table provides our total estimated proved reserve, probable reserve and possible reserve information prepared by Ryder Scott as of December 31, 2022, using NYMEX strip prices as of market close on December 31, 2022 and PV-10 Value and the Standardized Measure for such period. We have included this information in order to provide an additional method of presentation of the fair value of our assets and the cash flows that we expect to generate from those assets based on the market's forward-looking pricing expectations as of December 31, 2022. The historical 12-month pricing average in our December 31, 2022 disclosures above does not reflect the prevailing natural gas and oil futures. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of natural gas and oil prices as of a certain date, although we caution investors that this information should be viewed as a helpful alternative, not a substitute, for the data presented based on SEC Pricing. In addition, we believe that NYMEX strip pricing provides relevant and useful information because it is widely used by investors in our industry as a basis for comparing the relative size and value of our reserves to our peers. Our estimated reserves based on NYMEX futures were otherwise prepared on the same basis as our SEC reserves for the comparable period. Actual future prices may vary significantly from the NYMEX strip prices on December 31, 2022. Actual revenue and value generated may be more or less than the amounts disclosed. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. In addition, estimates of probable and possible reserves are inherently imprecise and are more uncertain than proved reserves but have not been adjusted for risk due to that uncertainty, and therefore they may not be comparable with each other and should not be summed either together or with estimates of proved reserves. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.*"

	December 31, 2022
Estimated proved developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	3,656,043
Producing	3,328,444
Non-producing	327,599
Natural gas liquids (MBbls)	163,725
Producing	150,473
Non-producing	13,252
Oil (MBbls)	1,059
Producing	1,059
Non-producing	—
Total estimated proved developed reserves (MMcfe)	4,644,747
Producing	4,237,636
Non-producing	407,111
Standardized Measure (millions)	3,250
PV-10 (millions)(1)	4,076
Estimated proved undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	1,021,746
Natural gas liquids (MBbls)	36,937
Oil (MBbls)	565
Total estimated proved undeveloped reserves (MMcfe)(2)(3)	1,246,758
Standardized Measure (millions)	415
PV-10 (millions)(3)(4)	$ 599
Estimated proved reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	4,677,789
Natural gas liquids (MBbls)	200,662
Oil (MBbls)	1,624
Total estimated proved reserves (MMcfe)	5,891,505
Standardized Measure (millions)	$ 3,665
PV-10 (millions)(5)	$ 4,675
Estimated probable developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	363,215
Natural gas liquids (MBbls)	25,556
Oil (MBbls)	—
Total estimated probable developed reserves (MMcfe)(3)(6)	516,551
Standardized Measure (millions)	$ 128
PV-10 (millions)(7)	$ 174
Estimated probable undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	511,913
Natural gas liquids (MBbls)	29,770
Oil (MBbls)	1,072
Total estimated probable undeveloped reserves (MMcfe)(3)(6)	696,965
Standardized Measure (millions)	$ 141
PV-10 (millions)(8)	$ 198

	December 31, 2022
Estimated total probable reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	875,128
Natural gas liquids (MBbls)	55,326
Oil (MBbls)	1,072
Total estimated probable reserves (MMcfe)(3)(6)	1,213,516
Standardized Measure (millions)	$ 269
PV-10 (millions)(9)	$ 372
Estimated possible developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	83,986
Natural gas liquids (MBbls)	8,143
Oil (MBbls)	—
Total estimated possible developed reserves (MMcfe)(3)(6)	132,844
Standardized Measure (millions)	$ 26
PV-10 (millions)(10)	$ 35
Estimated possible undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	458,394
Natural gas liquids (MBbls)	7,062
Oil (MBbls)	273
Total estimated possible undeveloped reserves (MMcfe)(3)(6)	502,406
Standardized Measure (millions)	$ 90
PV-10 (millions)(11)	$ 126
Estimated total possible reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	542,380
Natural gas liquids (MBbls)	15,205
Oil (MBbls)	273
Total estimated possible reserves (MMcfe)(3)(6)	635,248
Standardized Measure (millions)	$ 116
PV-10 (millions)(12)	$ 161

(1) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved developed reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 4,076
Present value of future income taxes discounted at 10%	(826)
Standardized Measure	$ 3,250

(2) Proved undeveloped reserves as of December 31, 2022 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

(3) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our PUD, probable and possible reserves, which may cause us to decrease the amount of our PUD, probable and possible reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our PUD, probable and possible reserves to become uneconomic to develop, which would cause us to remove them from their respective reserve category.

(4) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved undeveloped reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 599
Present value of future income taxes discounted at 10%	(184)
Standardized Measure	$ 415

(5) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 4,675
Present value of future income taxes discounted at 10%	(1,010)
Standardized Measure	$ 3,665

(6) Estimates of probable and possible reserves, respectively, and the respective future cash flows related to such estimates, are inherently imprecise and are more uncertain than proved reserves, and the future cash flows related to such estimates. For more information regarding the presentation of probable and possible reserves, see "— *Preparation of Reserves Estimates and Internal Controls.*"

(7) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated probable developed reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 174
Present value of future income taxes discounted at 10%	(46)
Standardized Measure	$ 128

(8) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated probable undeveloped reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 198
Present value of future income taxes discounted at 10%	(57)
Standardized Measure	$ 141

(9) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated probable reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 372
Present value of future income taxes discounted at 10%	(103)
Standardized Measure	$ 269

(10) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated possible developed reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 35
Present value of future income taxes discounted at 10%	(9)
Standardized Measure	$ 26

(11) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated possible undeveloped reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 126
Present value of future income taxes discounted at 10%	(36)
Standardized Measure	$ 90

(12) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated possible reserves as of December 31, 2022:

	December 31, 2022
PV-10 (millions)	$ 161
Present value of future income taxes discounted at 10%	(45)
Standardized Measure	$ 116

Preparation of Reserves Estimates and Internal Controls

Our reserve estimates as of December 31, 2020, December 31, 2021 and December 31, 2022 included in this prospectus are based on reports prepared by Ryder Scott, our independent reserve engineer, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC in effect at such time. We rely on Ryder Scott's expertise to ensure that our reserve estimates are prepared in compliance with SEC rules, regulations and disclosure guidelines and that appropriate geologic, petroleum engineering, and evaluation principles and techniques are applied in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers titled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of June 2019)." Copies of Ryder Scott's reserve reports are included as exhibits to the registration statement of which this prospectus forms a part.

The person at Ryder Scott responsible for the preparation of the reserve report is Stephen E. Gardner, a Licensed Professional Engineer in the State of Colorado (No. 44720). Mr. Gardner, an employee of Ryder Scott since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level. Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers, geoscience professionals, operations, land, finance and accounting, and marketing personnel prior to our annual reserves process, work closely together to ensure the integrity, accuracy and timeliness of data so that our reservoir engineering team can review such data and then furnish it to, and work with, our independent reserve engineers in their reserve evaluation process. Our internal reserves process follows a rigorous workflow where the multidisciplinary teams come together to vet our model assumptions and input and get final signoff before our technical team meets with the independent reserve engineers to review properties and discuss methods and assumptions used to prepare reserve estimates. Our Chief Technology Services Officer, Ethan Ngo, is primarily responsible for overseeing the independent reserve engineers during the process. Mr. Ngo has over 14 years of conventional and unconventional experience on and offshore across the lower 48 states with a major oil and gas company, independent oil and gas companies, and a private-equity-backed oil and gas company. Mr. Ngo has a BS in Civil Engineering and Masters in Petroleum Engineering and International Political Economy of Resources from the Colorado School of Mines, and a MBA from the University of Colorado, Denver.

Ryder Scott relies on various data provided by our internal reservoir engineering team in preparing its reserve estimates, including such items as oil and natural gas prices, ownership interests, production information, operating costs, planned capital expenditures and other technical data. Our internal reservoir engineering team consists of qualified petroleum engineers who maintain our internal evaluation of reserves and compare our information to the reserves prepared by Ryder Scott. Management is responsible for designing the internal control procedures used in the preparation of our oil and gas reserves, which include verification of data input into reserve forecasting and economics evaluation software, as well as multi-discipline management reviews. The internal reservoir engineering team reports directly to our Senior Vice President of Engineering.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved behind pipe (proved developed non-producing) oil and gas reserves are new reserves that can be expected to be recovered through existing wells, active or shut-in, where expenditure is required to access the new reserves. Proved undeveloped oil and gas reserves are 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 completion. Proved undeveloped reserves on undrilled acreage are limited to those locations on development spacing areas that are offsetting economic producers that are reasonably certain of economic production when drilled. Proved undeveloped reserves for other undrilled development spacing areas are claimed only where it can be demonstrated with reasonable certainty that there is continuity of economic production from the existing productive formation. Proved undeveloped reserves are included only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five years.

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 that 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 and possible reserves, respectively, and the respective future cash flows related to such estimates, and should not be summed arithmetically with estimates of either proved or possible reserves, respectively, and the respective 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. 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.

Estimates of possible reserves, and the future cash flows related to such estimates, are also inherently imprecise and are more uncertain than estimates of proved and probable reserves, respectively, and the respective future cash flows related to such estimates, but have not been adjusted for risk due to that uncertainty. Because of such uncertainty, estimates of possible reserves, and the future cash flows related to such estimates, may not be comparable to estimates of proved and probable reserves, respectively, and the respective future cash flows related to such estimates, and should not be summed arithmetically with estimates of either proved or probable reserves, respectively, and the respective 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 possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible 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, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve 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. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. 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 we believe 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.

Uncertainties are inherent in estimating quantities of proved, probable and possible reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development and production expenses, may require revision of such estimates. Accordingly, quantities of oil and natural gas ultimately recovered will vary from reserve estimates. See "*Risk Factors*" for a description of some of the risks and uncertainties associated with our upstream business and reserves.

Reserve estimates are based on production performance, data acquired remotely or in wells, and are guided by petrophysical, geologic, geophysical and reservoir engineering models. Estimates of our proved reserves were based on deterministic methods. In the case of mature developed reserves, reserve estimates are determined by decline curve analysis and in the case of immature developed and undeveloped reserves, by analogy, using proximate or otherwise appropriate examples in addition to volumetric and statistical analyses. The technologies and economic data used in estimating our proved reserves include empirical evidence through drilling results and well performance, well logs and test data, geologic maps and available surface and downhole pressure data, and production and reservoir data. Further, the internal review process of our wells and related reserve estimates includes but is not limited to the following:

- 3D seismic-based subsurface maps,
- Petrophysical estimates of original gas in place,
- Volumetric estimates for producing wells,
- Decline curve analysis,
- Rate transient and analytical model analysis,
- Statistical analysis and Monte Carlo simulation, and
- Fracture modeling.

Our estimated proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Regional variations in pricing and related deductions are similarly obtained and a 12-month average is calculated at year end.

For the years ended December 31, 2022, 2021 and 2020, Ryder Scott and our multidisciplinary team of technical and other professionals jointly reviewed our well performance and future development plans. Following that joint review, we furnished our internal reserve database and supporting data to Ryder Scott to facilitate their preparation of independent reserve estimates and final reports. Access to our database containing reserve information is restricted to select individuals from our engineering department.

Seasonality

Weather conditions have a significant impact on the demand for natural gas used for heating loads and natural gas-fired power generation. Demand for natural gas is generally at its lowest during the spring and fall months and peaks during the summer and winter months. Demand in the winter season peaks due to residential and commercial heating load demand, while the summer season peaks due to cooling loads, which calls on increased natural gas fired power generation loads. However, seasonal anomalies such as warmer than normal winters or cooler than normal summers can lessen the magnitude of the seasonal fluctuations in demand. In addition, natural gas storage facilities are utilized to bring additional supply to the market that is utilized to meet peak demand levels during both winter and summer seasons.

In addition to the demand side effects, specific seasonal weather events can also have an effect on available natural gas supply. In recent history, much colder than normal weather has induced wellhead freeze-offs in various regional supply markets, which ultimately lessens supply available to broader markets. Various weather events related to the summer months can similarly have detrimental effects on available supply also.

These seasonal anomalies can also increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations. Similarly, winter months may bring about delays in operational capabilities and efficiency of execution related to new and existing supply.

Enterprise Risk Management (ERM)

We have a standing risk management committee (“RMC”) which meets regularly and assesses, mitigates and provides direction on management of key enterprise risks. RMC members include executives and senior leaders within various functions such as legal, information technology, marketing, regulatory and sustainability, safety, security, operations, finance and accounting, and land.

COVID-19 Impact

Since the start of the COVID-19 pandemic, governments have tried to slow the spread of the virus by imposing social distancing guidelines, travel restrictions and stay-at-home orders, among other actions, which caused a significant decrease in activity in the global economy and the demand for oil, and to a lesser extent, natural gas and NGLs. As vaccines have become widely available, social distancing guidelines, travel restrictions and stay-at-home orders have eased, activity in the global economy has increased and demand for natural gas, NGLs and oil and related commodity pricing, has improved. However, new variants of the virus could cause further commodity market volatility and resulting financial market instability, and these are variables beyond our control that may adversely impact our operating cash flows, distributions from unconsolidated affiliates, our ability to pay dividends on our common stock and our ability to access the capital markets.

As a producer of natural gas and NGLs, we are recognized as an essential business under various federal, state and local regulations related to the COVID-19 pandemic. As such, we have continued to operate throughout the pandemic as permitted under these regulations while taking steps to protect the health and safety of our workers. We have implemented protocols to reduce the risk of an outbreak within our field operations and corporate offices, and these protocols have not reduced our production and our throughput in a significant manner. A substantial portion of our non-field level employees currently operate in remote work from home arrangements, and we have been able to effectively maintain our day-to-day operations. We continue to monitor the COVID-19 environment in order to protect the health and safety of our employees and contract workers.

Our supply chain has not experienced any significant interruptions as a result of the COVID-19 pandemic. The lack of a market or available storage for any one NGL product or oil could result in our having to delay or discontinue well completions and commercial production or shut-in production for other products because we cannot curtail the production of individual products in a meaningful way without reducing production of other products. Potential impacts of these constraints may include partial shut-in of production, although we are not able to determine the extent of shut-ins or for how long they may last. However, because some of our wells produce rich gas, which is processed, and some produce lean gas, which does not require processing, we can change the mix of products that we produce and wells that we complete to adjust our production to address takeaway capacity constraints for certain products. For example, we can shut-in rich gas wells and still produce from our lean gas wells if processing or storage capacity of NGL products becomes limited or constrained.

Customers and Product Marketing

We utilize an unaffiliated third party to market all of our natural gas and oil production to various purchasers, which consist of credit-worthy counterparties, including utilities, LNG producers, industrial consumers, major corporations and super majors, in our industry. This third party collects directly from the purchasers and remits to us the total of all amounts collected on our behalf less their fee for making such sales. We do not believe the loss of any customer would have a material adverse effect on our business, as other customers or markets are currently accessible to us.

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and natural gas, available storage, the proximity of our natural gas and oil production to pipelines and corresponding markets, the available capacity in such pipelines, the demand for natural gas and oil, the effects of weather, and the effects of state and federal regulation. While we have not experienced significant difficulty in finding a market for our production as it becomes available or in transporting our production to those markets, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Marketing and Differentials

In NEPA, we continually monitor ongoing market dynamics to ensure equity gas sales are well positioned in terms of market optionality and counterparty liquidity. Within our operating area, sales are generally exposed to indices (denoted in parentheses) located on Eastern Gas Pipeline (South), Millennium Pipeline (East Pool), Tennessee Gas Pipeline (Zone 4) and Transco Pipeline (Leidy). From time to time, we will enter into longer-term commitments with downstream pipelines for firm transportation service. As of December 31, 2022, we have multiple contracts for firm transportation services including a combined 90,000 MMBtu/d to various locations on Tennessee Gas Pipeline, 27,500 MMBtu/d on Millennium Pipeline and 20,000 MMBtu on Eastern Gas Pipeline, which provide access to premium markets in New England (Algonquin), the Northeast and Gulf Coast areas. The remaining term on these contracts range from one year to 15 years, with an average remaining duration of 7.25 years as of December 31, 2022.

In the Barnett, we have several firm transportation contracts specific to the Devon Barnett Acquisition to transport natural gas volumes out of the Barnett to premium markets, including 200,000 MMBtu/d to the Katy area, 200,000 MMBtu/d of intra-basin aggregation transport, which feeds 200,000 MMBtu/d of interstate transport to Transco Zone 4 Station 85, and 80,000 MMBtu/d to NGPL-TxOk with term end dates ranging through 2023 and 2027. The capacity to NGPL-TxOk is currently approximately 15,000 MMBtu/d deficient; however, we reserve the right to tranche this capacity down annually to match production. BKV is currently negotiating extensions of several Barnett transport agreements to preserve optionality to transport volumes out of the Barnett.

We were assigned 270,000 MMBtu/d of firm transport on Energy Transfer and Houston Pipe Line Company LP in connection with the closing of the Exxon Barnett Acquisition, which firm transport will expire in 2027. The contract with Energy Transfer and Houston Pipe Line provides access to the NGPL-TxOk market. Additionally, we executed a transaction confirmation with XTO Energy, Inc., which had the structural effect of assigning 170,000 MMBtu/d of firm capacity on Midcontinent Express Pipeline providing access to premium markets at Transco Zone 4 Station 85. Such contract expired on November 1, 2022 and BKV is currently negotiating to replace the expired capacity and maintain access to such markets.

As it relates to Temple I, in addition to 2,812,500 MMBtu of storage at Energy Transfer’s Bammel storage facility which expires in late 2027, BKV-BPP Power holds 75,000 MMBtu/d of firm transport with Energy Transfer and its subsidiaries which supports receipt of gas from the Katy Area with delivery to the Temple Facility and expires in late 2027. Additionally, Temple I holds 125,000 MMBtu/d of interruptible transport with Atmos Pipeline for delivery to Temple I, which terminates upon cancellation by the parties.

Unless otherwise mentioned, under all firm transportation contracts, we pay reservation fees, regardless of usage, to hold transportation rights of the contracted volume on these pipelines for the duration of the contract. Our minimum aggregate required payments per year under firm gathering and transportation agreements are approximately $62.3 million for 2023, $42.6 million for 2024, $23.2 million for 2025, $21.3 million for 2026, $20.0 million for 2027, and $64.0 million for 2028 and beyond. The utilization and economic optimization of the upstream business units' firm transportation contracts are currently managed by Concord Energy, LLC, who acts as the marketing agent for all our upstream marketed volumes. We believe that all NEPA, Barnett and Temple I transport contracts are at competitive rates.

Competition

The oil and gas industry is very competitive, and we compete with a substantial number of other companies, many of which are large, well-established and have greater financial and operational resources than we do. We compete with several other onshore unconventional natural gas producers to deliver our products to the marketplace, some of which include TotalEnergies and Lime Rock Resources (operating in the Barnett), Chesapeake Energy Corporation, Repsol USA, Coterra Energy Inc. and Southwestern Energy Company (operating in NEPA), among others.

Some of our competitors not only engage in the acquisition, exploration, development and production of oil and gas reserves and electricity generation, but also carry-on refining operations and the marketing of refined products. In addition, the oil and gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers, including alternative energy sources. Competition is particularly intense in the acquisition of prospective oil and gas properties. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. We also compete with other oil and gas companies to secure drilling rigs, frac fleets, sand and other equipment and materials necessary for the drilling and completion of wells and in the recruiting and retaining of qualified personnel. Such materials, equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. Many of our larger competitors may have a competitive advantage when responding to commodity price volatility and overall industry cycles. Further, the current inflation may affect us more than it may affect some of our larger competitors.

Environmental, Health, Safety and Climate Change Considerations

We understand the impact climate change has on our community, the world and future generations, which is why addressing these impacts in how energy is produced is a top priority. In particular, it is one of our core values, "Be One BKV," to create a unified team with a shared vision to achieve our emission reduction and energy impact goals.

We have established a Working Team consisting of a cross-functional group of BKV leaders who specialize in ESG strategy that meets periodically to identify, assess and implement critical ESG program initiatives. In addition, we have a Risk Management Committee that includes representatives from our operations, legal, finance, investor relations, information technology, marketing and environmental compliance teams and meets periodically to review potential ESG and other risks, tracks how these risks may be changing and ensures they are being properly managed. Our executive short-term incentive plan is tied to ESG-related initiatives, such as operational safety goals, social goals related to employee engagement and the establishment and implementation of our ESG program. In 2022, we achieved our operational safety goals by having zero major incidents (such as well control issues or explosions), having one regulatory violation and having two reportable incidents or injuries (TRIR 0.21). In 2022, we achieved our social goals relating to employee engagement with greater than 90% employee participation in our employee engagement survey, which led to the identification of areas for improvement, including career development, recognition and feedback. Also, we exceeded our ESG program goals by establishing our baseline score for transparent quantification of BKV's emission inventory and developing and executing substantial emission reduction. The baseline emissions values will be utilized to measure our emission reduction progress and future goals. In connection with our emissions reduction goals, we have established our baseline emissions inventory and are deploying our emissions monitoring ecosystem and executing our "Pad of the Future" and other emissions reduction programs. For example, we utilized the upstream operations emissions baseline completed in 2021, which was updated in connection with the Exxon Barnett Acquisition, to refine and measure our emission reductions goals and progress, which include year-over-year step-down reduction projections through 2025. Through these efforts, by December 31, 2022, we completed emission reducing conversions on approximately 2,000 of the approximately 6,000 wells we plan to include in our "Pad of the Future" program by the end of 2025. This reduction of over 380,000 $MtCO_2e$ is reflected in our updated baseline based on reporting year 2022 Subpart W emissions.

We also have established robust Environmental, Health, Safety and Regulatory (“EHSR”) goals with proven results. At the management level, our EHSR programs are overseen directly by our Chief Executive Officer and Chief Operating Officer. Our Director of EHSR reports to our Chief Operating Officer, providing direct access to executive management and decision-making with respect to our top priority focus of EHSR performance. Our safety performance ranks high in comparison to our peers, and we have achieved a Total Recordable Incident Rate (TRIR) of zero in 2019 through 2021 and a 0.21 in 2022, which includes both our employees and our contractors. Through December 31, 2022, our employees have driven, on average, a total of nearly 3,000,000 miles per year, during which time we have had zero at-fault driving incidents. We recorded our first at fault incident in the first quarter of 2023. Regarding our environmental and safety performance, we have received zero notices of violation that have carried a penalty in 2020, 2021, 2022 and 2023 through the date of this prospectus. We have established a four-tiered emissions monitoring ecosystem through which we monitor our wells and facilities via satellite, fixed wing aircraft, continuous perimeter sensors (largely through our Project Canary partnership), and handheld Forward Looking Infrared (FLIR) cameras. We completed a self-audit of our environmental management system in the third quarter of 2022 for alignment to ISO 14001 (a set of environmental management standards). We have certified 100% of our production in NEPA with Project Canary TrustWell and achieved a Gold rating for all wells; a strong rating that will enable us to sell RSG. As of December 31, 2022, in the Barnett, we had received TrustWell certification for 168 wells on 64 pads and have achieved Gold rating for these wells. We expect to continue the TrustWell certification process throughout our Barnett assets in the coming years.

As a top 20 gas-weighted natural gas producer in the U.S. market, we believe we have a significant opportunity to reduce our environmental footprint by reducing GHG emissions through a series of strategic projects and technological commitments, and by offsetting remaining operational emissions. We have set a goal of reaching net zero Scope 1 and 2 emissions across our owned and operated upstream businesses by the end of 2025. To achieve our net zero goals, we invested approximately $9.1 million in 2022 to reduce emissions from our operations. These investments allowed us to prototype and deploy electrified components into the production processes, convert pneumatic gas instruments, enhance measurement technology, remove redundant equipment and develop and draw on renewable energy sources, among other operational improvements. For our Scope 3 profile, we aspire to offset 100% of our combined Scope 1, 2 and 3 emissions from our owned and operated upstream businesses by the early 2030s. We believe we have a path to these net-zero goals through the expansion of our carbon negative businesses, such as significant expansion of our CCUS activities and our ongoing BKV dCarbon Ventures efforts. We believe we can achieve these goals if certain of the ten identified potential CCUS projects in our project pipeline are completed upon terms that we believe are obtainable. In addition to the twelve CCUS projects we have identified, we expect to continue to identify and evaluate additional CCUS projects.

Our CCUS business and all of our CCUS projects are in the early stages of development and while we have reached FID and entered into definitive agreements with respect to the Barnett Zero Project and reached internal FID for the Cotton Cove Project, we have not reached FID or executed any definitive agreements with respect to the other ten potential projects we have identified above and may not be able to reach agreement on terms acceptable to us, or to achieve our projected timeline for commercial operations. In addition, the development of our CCUS business is expected to require material capital investments, and the commercial viability of our CCUS projects depends, in part, on certain financial and tax incentives provided by the U.S. federal government. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits, the details of which have been released only in part with additional details expected in future guidance. For more information on our CCUS business, see “*— Overview — Our Operations — Carbon Capture, Utilization and Sequestration” and “— Our Operations — Carbon Capture, Utilization and Sequestration*.” For more information about the risks involved in our CCUS business, see “*Risk Factors — Risks Related to Our CCUS Business*.” Another way we are enabling CO_2 emission reduction from our operations is by increasing our production of RSG. We received Project Canary’s TrustWell environmental assessment Gold rating in 2021 across our entire Marcellus Shale (NEPA) operations, earning the highest score achieved for wells taken over by a new operator. In 2022, we certified a portion of our Barnett production and recertified our entire NEPA operations, in each case, earning a Gold rating environmental assessment.

Human Capital Resources

As of December 31, 2022, we had a total of 374 employees, which includes employees added following the completion of the Exxon Barnett Acquisition. We hire independent contractors on an as needed basis. We believe we have good relations with our employees. We and our employees are not subject to any collective bargaining agreements.

Safety. Safety is our highest priority, including the prevention of any releases from our operations. We conduct routine maintenance and inspections at our facilities, and we have established practices and operational infrastructure to control and mitigate potential spills or discharges. We also offer annual specialized training to staff on spill prevention and host routine Response Tabletop Sessions to ensure our teams are fully trained on our response plan in the event of any releases. We believe these measures continue to strengthen our process safety culture.

Compensation and Benefits. We recognize that our employees are our most valuable resource and that we must provide competitive compensation to ensure we attract and retain top talent. As part of our commitment to these efforts, we underwent a third-party evaluation to confirm our compensation was both competitive and reflective of the work our employees were performing. We have standardized our job and pay structure based on best practices and market data. We continue to survey and update our pay structure to stay competitive with our peers. We have implemented a compensation framework that strives to pay employees fairly and consistently based on their skills, experience and performance and that we believe is competitive compared to other companies in our industry.

To foster the health and well-being of our employees and their families, we offer all of our full- and part-time employees access to financial, health and wellness programs. We also offer a matched 401(k) plan, short-term and long-term incentive plans, medical insurance coverage, parental leave, and paid time off for holidays, personal days and vacation.

Diversity and Inclusion. We strongly believe that a diverse workforce fosters new ideas and makes us stronger as a company. Providing a safe, inclusive working environment for our employees and contractors is among our top priorities. Our executive leaders are committed sponsors and supporters of programs that foster an increase in diverse demographic representation, nurture the careers of underrepresented groups and create a greater sense of inclusion and belonging.

In 2021, we implemented a new code of business conduct, updating our employee policies and completing an employee handbook refresh. Among the policies that were updated was our whistleblower policy. In conjunction with the update of the whistleblower policy, we launched our confidential ethics and compliance hotline (in addition to our online submission portal).

In 2022, we implemented a comprehensive manager and employee online training program across the Company that includes topics such as business ethics, human rights and diversity, equity and inclusion and that will be tracked to ensure participation.

We are also prioritizing the formal buildout of employee resource groups to create more opportunity for colleagues and peers to connect with others facing similar situations or challenges.

Human Rights. Providing a safe, inclusive working environment for our employees and contractors is a priority. We do not tolerate discrimination or harassment of any kind. We also have a Human Rights Policy that applies to all of our employees and is aligned with the UN Declaration of Human Rights and the UN Guiding Principles on Business and Human Rights. We continue to monitor the effectiveness of our human rights policy with the goal of growing and aligning our business to the dynamic rights of our workforce. Our Human Rights Policy extends to all our operations, as well as partners and suppliers, including security providers.

Recruitment, Retention and Development. We provide equal opportunity for all employees and consultants regardless of race, religion, gender, sexual orientation, age, ethnic or national origin, social origin, disability, family status or any other protected status and personal characteristics for all aspects of employment. This applies to recruitment and talent attraction, training and professional development opportunities, promotions and all employee benefits. Additionally, we prioritize local hiring for both employees and contractors, particularly in areas of field operations, to support employment opportunities in our local communities.

Government Regulation and Environmental Matters

Our operations are subject to extensive federal, state and local laws and regulations that govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require notice to stakeholders of proposed and ongoing operations;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to plug and abandon wells.

Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities for failure to comply. Violations and liabilities with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and cash flows. In certain instances, citizens or citizen groups also have the ability to bring legal proceedings against us if we are not in compliance with environmental laws or to challenge our ability to receive environmental permits that we need to operate. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2022, we have recorded asset retirement obligations of $182.3 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general.

We believe that we are in material compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition, results of operations or cash flows. Nevertheless, changes in existing environmental laws or regulations or the adoption of new environmental laws or regulations, including any significant limitation on the use of hydraulic fracturing, could have the potential to adversely affect our financial condition, results of operations and cash flows. Federal, state or local administrative decisions, developments in the federal or state court systems or other governmental or judicial actions may influence the interpretation or enforcement of environmental laws and regulations and may thereby increase compliance costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

The following is a summary of the significant environmental laws to which our business operations are subject.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, is also known as the "Superfund" law. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on parties that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Such "responsible parties" may be subject to joint and several liability under CERCLA 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 the hazardous substances released into the environment. We currently own or lease properties that have been used for the exploration and production of natural gas, NGLs and oil for a number of years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other wastes may have been disposed of or released on or under the properties currently owned or leased by us. Many of these properties have been operated by third parties whose treatment or release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, may be subject to CERCLA, and we could potentially be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination. States also have environmental cleanup laws analogous to CERCLA, including Texas.

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA. While there is currently an exclusion from RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or gas, it is possible that some of these wastes could be classified as hazardous waste in the future and therefore be subject to more stringent regulation under RCRA. For example, in December 2016, the EPA and certain environmental organizations entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production-related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree required the EPA to propose a rulemaking no later than March 15, 2019, for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary; the EPA ultimately determined that a revision was not necessary. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Oil Pollution Act. The Oil Pollution Act of 1990, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term "waters of the United States" has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs, and certain other damages arising from a spill. As such, a violation of the OPA has the potential to adversely affect our business, financial condition, results of operations and cash flows.

Clean Water Act. The CWA and implementing regulations, which are primarily executed through a system of permits, also govern the discharge of certain pollutants into waters of the United States. Enforcement for failure to comply strictly with the CWA are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities or to cease hauling wastewaters to facilities owned by others that are the source of water discharges to resolve non-compliance. The CWA also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil. In 2016, the EPA finalized new wastewater pretreatment standards that would prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs. In addition, state laws analogous to the CWA also may require permits for certain of our operations.

Safe Drinking Water Act. The SDWA and comparable local and state provisions restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including oil and gas wastewater disposal wells or enhanced oil recovery) is governed by U.S. federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state's environmental authority. The SDWA's UIC Program requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for UIC well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the UIC wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. In addition, in some instances, the operation of UIC wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of UIC wells, and regulators in some states have imposed or are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells. The adoption of federal, state and local legislation and regulations intended to address induced seismic activity in the areas in which we operate could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays, and is generally exempted from federal regulation as underground injection (unless diesel is a component of the fracturing fluid) under the SDWA. Concerns have been raised that hydraulic fracturing activities, separate and apart from use of UIC wells, may be correlated to induced seismicity. In addition, EPA conducted a comprehensive study of the potential adverse impacts of hydraulic fracturing on drinking water and ground water and released its final report on this study in December 2016. The report found that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. This study and other studies that may be undertaken by the EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the SDWA, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing. Such costs and burdens could delay the development of unconventional gas resources from shale formations, which are not commercially feasible without the use of hydraulic fracturing.

Chemical Disclosures Related to Hydraulic Fracturing. A number of states, including Texas, have implemented chemical disclosure requirements for hydraulic fracturing operations. We currently disclose all hydraulic fracturing additives we use on www.FracFocus.org, a website created by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

Prohibitions and Other Regulatory Limitations on Hydraulic Fracturing. There have been a variety of regulatory initiatives at the state level to restrict oil and gas drilling operations in certain locations.

In addition to chemical disclosure rules, some states have implemented permitting, well construction or water withdrawal regulations that may increase the costs of hydraulic fracturing operations. For example, Texas has water withdrawal restrictions allowing suspension of withdrawal rights in times of shortages while other states require reporting on the amount of water used and its source.

Increased regulation of and attention given by environmental interest groups, as well as state and federal regulatory authorities, to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and gas, including from developing shale plays, or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or existing wells. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing that are more stringent could cause a decrease in the completion of new oil and gas wells, as well as increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We use hydraulic fracturing extensively and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and gas that we can economically recover.

Clean Air Act. Our operations are subject to the Clean Air Act, or the CAA, and comparable state and local requirements to control emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permitting requirements. Federal and state laws designed to control toxic air pollutants and GHGs might require installation of additional controls. Payment of fines and correction of any identified deficiencies generally resolve any failures to comply strictly with air regulations or permits. However, in the event of non-compliance, regulatory agencies could also require us to cease construction or operation of certain facilities or to install additional controls on certain facilities that are air emission sources. Further, stricter requirements could negatively impact our production and operations.

In 2012, the EPA published final New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, that amended the existing NSPS and NESHAP for the oil and natural gas sector. In June 2016, the EPA published a final rule that updated and expanded the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In June 2017, the EPA proposed a two-year stay of certain requirements contained in the June 2016 rule. In March 2018, the EPA published a final rule that amended two narrow provisions of the NSPS, removing the requirement for completion of delayed repair during emergency or unscheduled vent blowdowns. In September 2020, the EPA published a final rule amending the 2012 and 2016 NSPS for the oil and natural gas sector that removed transmission and storage sources from the oil and natural gas industry source category and rescinded the methane requirements applicable to the production and processing sources. On June 30, 2021, President Biden signed into law a joint Congressional resolution under the Congressional Review Act nullifying the September 2020 rule amending the EPA’s 2012 and 2016 NSPS standards for the oil and natural gas sector and effectively reinstating the prior standards. On November 15, 2021, the EPA proposed rules to reduce methane emissions from both new and existing oil and natural gas industry sources (“2021 Proposed Methane Rules”). On November 11, 2022, the EPA issued a supplemental proposal to update, strengthen and expand the 2021 Proposed Methane Rules that would make the proposed requirements more stringent and include sources not previously regulated under the oil and gas source category. The EPA has announced that it intends to finalize these rulemakings in 2023. The reinstatement of direct regulation of methane emission for new sources, promulgation of requirements for existing oil and gas sources and enhanced requirements for new sources, and the expansion of sources covered by the EPA’s rules, could result in increased compliance costs or otherwise impact our results of operations. For additional information, see “*Risk Factors — Risks Related to Environmental, Legal Compliance and Regulatory Matters — Our operations are subject to a series of risks relating to climate change that could result in increased compliance or operating costs, limit the areas in which we may conduct natural gas and NGL exploration and production activities, and reduce demand for the natural gas and NGLs we produce.*”

In October 2015, the EPA revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. The EPA finished promulgating final area designations under the new standard in 2018, which, to the extent areas in which we operate have been classified as non-attainment, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Generally, it will take the states several years to develop compliance plans for their non-attainment areas. In December 2020, the EPA completed its review of the currently available scientific evidence and risk information and decided to retain the existing ozone National Ambient Air Quality Standards. While we are not able to determine the extent to which this standard will impact our business at this time, it has the potential to have a material impact on our operations and cost structure.

In June 2016, the EPA finalized a rule “aggregating” individual wells and other facilities and their collective emissions for purposes of determining whether major source permitting requirements apply under the CAA. These changes may introduce uncertainty into the permitting process and could require more lengthy and costly permitting processes and more expensive emission controls.

Collectively, these rules and proposed rules, as well as any future laws and their implementing regulations, may require a number of modifications to our operations. We may, for example, be required to install new equipment to control emissions from our well sites or compressors at initial startup or by the applicable compliance deadline. We may also be required to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Greenhouse Gas and Climate Change Laws and Regulations. Scientific studies have concluded that increasing concentrations of GHGs in the Earth’s atmosphere are producing climate changes that have significant physical effects. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes, droughts, or floods) or longer-term shifts in climate patterns that may cause sea level rise or chronic heat waves. Potential physical risks may cause direct damage to our assets as well as indirect impacts such as supply chain disruption and also could include changes in water availability, sourcing, and quality, which could impact drilling and completion operations. These physical risks could cause increased costs, production disruptions, lower revenues and substantially increase the cost or limit the availability of insurance. In response to studies indicating that emissions of carbon dioxide and certain other GHGs, including methane, are contributing to global climate change, there is increasing focus by local, state, regional, national and international regulatory bodies as well as by investors and the public on GHG emissions and climate change issues.

While the United States has yet to adopt comprehensive climate change legislation, the federal government has taken a series of administrative actions aimed at curtailing GHG emissions. For example, in response to 2009 findings that emissions of CO_2, methane and other GHGs present an endangerment to public health and the environment, the EPA issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources.

In August 2015, the EPA promulgated the Clean Power Plan (“CPP”) rule to limit CO_2 emissions from existing coal and natural-gas fired electric generating units. The CPP rule, which never went into effect, adopted a sector-wide, generation shifting approach and determined the best system of emissions reduction (BSER) for CO_2 at coal and natural-gas fired units included three components — heat rate improvement at existing coal-fired units, a shift in generation from coal-fired to natural-gas fired units, and a shift in generation from natural-gas fired facilities to renewables. Several industry groups and states challenged the CPP rule. On February 9, 2016, the U.S. Supreme Court stayed the implementation of the CPP rule pending judicial review. In August 2019, the EPA repealed the CPP rule and replaced it with the Affordable Clean Energy rule, or ACE rule, which adopted a narrower, source-based approach limited to designating heat rate improvement, or efficiency improvement, as the BSER for CO_2 from existing coal-fired electric generating units. The ACE rule and the repeal of the CPP rule were challenged by several states and private parties. On January 19, 2021, the D.C. Circuit vacated the ACE rule but at the EPA’s request subsequently stayed issuance of the portion of the mandate that would have vacated the repeal of the CPP rule while the EPA decided whether it would promulgate a new rule instead of the CPP rule. On October 29, 2021, the U.S. Supreme Court agreed to review the D.C. Circuit’s decision, and on June 30, 2022 the U.S. Supreme Court ruled that the generation-shifting approach included in the CPP rule exceeded EPA’s statutory authority under the CAA. The EPA is expected to propose new rules to regulate GHG emissions from electric generating units, but whether and how such rules would affect our business is uncertain.

The EPA has issued the “Final Mandatory Reporting of Greenhouse Gases” Rule and a series of revisions to it, which requires operators of oil and gas production, natural gas processing, transmission, distribution and storage facilities and other stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report annually their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. The EPA widened the scope of annual GHG reporting to include not only activities associated with completion and workover of gas wells with hydraulic fracturing and activities associated with oil and gas production operations, but also completions and workovers of oil wells with hydraulic fracturing, gathering and boosting systems, and transmission pipelines. These rules do not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits. More recently, on November 15, 2021, the EPA proposed rules to reduce methane emissions from new and modified sources in the oil and gas sector ("2021 Proposed Methane Rules"). The 2021 Proposed Methane Rules proposal was supplemented by the EPA on November 11, 2022, to update, strengthen and expand the 2021 rule proposal. For more information, see "*Risk Factors — Risks Related to Environmental, Legal Compliance and Regulatory Matters — Our operations are subject to a series of risks relating to climate change that could result in increased compliance or operating costs, limit the areas in which we may conduct natural gas and NGL exploration and production activities, and reduce demand for the natural gas and NGLs we produce*."

In certain circumstances, large sources of GHG emissions are subject to preconstruction permitting under the EPA's Prevention of Significant Deterioration program. This program historically has had minimal applicability to the oil and gas production industry. However, there can be no assurance that our operations will avoid applicability of these or similar permitting requirements, which impose costs relating to emissions control systems and the efforts needed to obtain the permit.

In April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions ("NDC"), which set GHG emission reduction goals, every five years beginning in 2020. In November 2019, the Trump Administration formally moved to exit the Paris Agreement, initiating the treaty-mandated one-year process at the end of which the United States officially exited the agreement. However, the current Presidential administration has made climate change a central priority and on January 20, 2021, his first day in office, President Biden announced its intention to rejoin the Paris Agreement. The United States officially rejoined the Paris Agreement on February 19, 2021, and in April 2021 submitted its NDC. The United States NDC sets an economy-wide target of net GHG emissions reduction from 2005 levels of 50-52% by 2030. The specific measures to be taken in furtherance of achieving this target have not been established, but the NDC submission indicated that an interagency approach will play an important role, including regulatory, technology and policy initiatives designed to reduce the generation of GHG emissions and to incentivize the capture and geologic sequestration or utilization of carbon dioxide that would otherwise be emitted in the atmosphere. Also on his first day in office, President Biden signed an executive order on climate action and reconvened an interagency working group to establish interim and final social costs of three GHGs: carbon dioxide, nitrous oxide, and methane. Carbon dioxide is released during the combustion of fossil fuels, including natural gas, NGLs and oil, and methane is a primary component of natural gas. The Biden Administration stated it will use updated social cost figures to inform federal regulations and major agency actions and to justify aggressive climate action as the United States moves toward a "100% clean energy" economy with net-zero GHG emissions.

The United States Congress has also passed a number of bills in recent years aimed at addressing climate change in a limited manner, primarily directed at funding climate change initiatives. The 2021 Infrastructure and Investment Jobs Act passed by Congress in November 2021 included measures aimed at decarbonization to address climate change, including funding for replacing transit vehicles, including buses, with zero- and low-emission vehicles and for the deployment of an electric vehicle charging network nationwide. This legislation, and other future laws, that promote a shift toward electric vehicles could adversely affect the demand for our products. Similarly, the Inflation Reduction Act, recently passed by Congress, imposed several new climate-related requirements on oil and gas operations. Moreover, in August 2022, Congress passed, and President Biden signed into law, the Inflation Reduction Act of 2022, which appropriates significant federal funding for renewable energy initiatives and, for the first time ever, imposes a fee on GHG emissions from certain facilities. The emissions fee and funding provisions of the law could increase our operating costs and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations.

In the absence of comprehensive climate change legislation at the federal level, a number of state and regional efforts have emerged. These include measures aimed at tracking and/or reducing GHG emissions through cap-and-trade programs, which typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting GHGs. In addition, a coalition of over 20 governors of U.S. states formed the United States Climate Alliance to advance the objectives of the Paris Agreement, and several U.S. cities have committed to advance the objectives of the Paris Agreement at the state or local level as well. To this end, the California governor issued an executive order on September 23, 2020 ordering actions to pursue GHG emissions reductions, including a direction to the California State Air Resources Board to develop and propose regulations to require increasing volumes of new zero-emission passenger vehicles and trucks sold in California over time, with a targeted ban of the sale of new gasoline vehicles by 2035.

If we are unable to recover or pass through a significant portion of our costs related to complying with current and future regulations relating to climate change and GHGs, it could materially affect our operations and financial condition. Any future laws or regulations that limit emissions of GHGs from our equipment and operations could require us to both develop and implement new practices aimed at reducing GHG emissions, such as emissions control technologies, which could increase our operating costs and could adversely affect demand for the oil and gas that we produce. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Future implementation or adoption of legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy. At this time, it is not possible to quantify the impact of any such future developments on our business.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations, and the provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The ESA was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas it believes are necessary for survival of a threatened or endangered species. While some of our facilities are in areas that may be designated as a habitat for endangered species, we believe that we are in substantial compliance with the ESA. The presence of any protected species or the final designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs from species protection measures or could result in limitations, delays, or prohibitions on our exploration and production activities that could have an adverse effect on our ability to develop and produce our reserves.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands trigger review under the National Environmental Policy Act. The National Environmental Policy Act requires federal agencies, including the U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment of the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. This process has the potential to delay or even halt development of some of our oil and gas projects.

Operating Hazards and Insurance

Natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pipe, casing or cement failures, abnormal pressure, pipeline leaks, ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters and other environmental hazards and risks.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot provide assurance that any insurance we obtain will be adequate to cover our losses or liabilities. We have elected to self-insure for certain items for which we have determined that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

The insurance policies we currently maintain, and their respective policy limits, are as follows:

- *Commercial General Liability*: $2,000,000 annual general aggregate policy limit or $1,000,00 per occurrence.
- *Property*: annual aggregate policy limits of $1,575,715 for personal property and $50,000 to $3,200,000 for certain real property.
- *Operators Extra Expense*:
  - $25,000,000 per occurrence limit for wells located in Pennsylvania;
  - $15,000,000 per occurrence limit for wells located in Texas;
  - $30,000,000 per occurrence additional limit for property under our care, custody or control;
  - $2,500,000 per occurrence additional limit for certain materials and supplies; and
- *Oil Lease Property*: $314,293,392 annual aggregate policy limit for physical loss and/or physical damage to certain scheduled onshore property.
- *Business and Contingent Business Interruption*: $64,240,000 annual aggregate limit per accident or occurrence, or $176,000 per day.
- *Site Pollution Incident Legal Liability*: $11,000,000 annual aggregate policy limit, with a $10,000,000 limit per incident.
- *Management Liability*:
  - $5,000,000 annual aggregate policy limit for director, officer and organizational liability, with an additional $1,000,000 of coverage for claims against certain insured persons;
  - $2,000,000 annual aggregate policy limit for employment practices liability;
  - $1,000,000 aggregate policy limit for fiduciary liability; and
  - $1,000,000 for certain crime liability.
- *Automobile Liability*: $1,000,000 aggregate policy limit.
- *Workers' Compensation*: limited to the value of the benefits required under Colorado, Montana, Oregon, Pennsylvania or Texas law, as applicable.
- *Employer's Liability*: $1,000,000 limit per accident for bodily injury by accident, and $1,000,000 aggregate policy limit for bodily injury by disease.
- *Umbrella Excess Liability*: $75,000,000 aggregate policy limit covering damages in excess of policy limits for commercial general liability, automobile liability, employee benefits liability and employer's liability.
- *Cybersecurity and Identity Fraud Liability*: $3,000,000 aggregate policy limit for cybersecurity incidents and $5,000 per victim of identity fraud.
- *Kidnap and Ransom*: $10,000,000 limit per insured event.

For more information about potential risks that could affect us, see "*Risk Factors — Risks Related to Our Business Generally — Our business is subject to operating hazards that could result in substantial losses or liabilities for which we may not have adequate insurance coverage*."

Other Facilities

Our corporate headquarters are located at 1200 17th Street, Suite 2100, Denver, Colorado 80202, and our telephone number at such address is (720) 375-9680. Our corporate headquarters are leased and our field office facilities are owned, and we believe that they are adequate for our current needs.

Title to Properties

Title to our oil and gas properties is subject to royalty, overriding royalty, carried, net profits, working, and similar interests customary in the oil and gas industry. Our properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements, and restrictions, and for current taxes not yet due. Our general practice is to conduct title examinations on material property acquisitions. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work is performed. The methods of title examination that we have adopted are reasonable in the opinion of management and are designed to ensure that production from our properties, if obtained, will be salable by us. We believe that title to our oil and natural gas properties is good and defensible, subject only to such exceptions that we believe do not materially interfere with the use of such properties.

Legal Proceedings

From time to time, we may be subject to various claims, title matters and legal proceedings arising in the ordinary course of business, including environmental contamination claims, personal injury and property damage claims, claims related to joint interest billings and other matters under natural gas operating agreements and other contractual disputes. While the outcome and impact on the Company cannot be predicted with certainty, we believe that our ultimate liability with respect to any such matters will not have a significant impact or material adverse effect on our financial positions, results of operations or cash flows. Our results of operations and cash flows, however, could be significantly impacted in the reporting periods in which such matters are resolved.

MANAGEMENT

Directors and Executive Officers

The following table provides information regarding the individuals who are expected to constitute our executive officers and directors upon completion of this offering. Executive officers serve at the discretion of our board of directors and until their successors are elected and qualified. Messrs. C. Vongkusolkit and S. Vongkusolkit are father and son, respectively.

Name	Age	Current Position(s) with the Company
Christopher P. Kalnin	45	Chief Executive Officer and Director
John T. Jimenez	53	Chief Financial Officer
Eric S. Jacobsen	52	Chief Operating Officer
Barry S. Turcotte	52	Chief Accounting Officer
Brid C. Kealey	60	Chief Human Resources Officer
Lindsay B. Larrick	40	Chief Legal Officer
Ethan Ngo	41	Chief Technical Services Officer
Chanin Vongkusolkit	70	Chairman of the Board
Somruedee Chaimongkol	61	Director
Joseph R. Davis	72	Director
Akaraphong Dayananda	63	Director
Carla S. Mashinski	60	Director
Thiti Mekavichai	61	Director
Charles C. Miller III	70	Director
Sunit S. Patel	61	Director
Anon Sirisaengtaksin	70	Director
Sinon Vongkusolkit	33	Director

Christopher P. Kalnin has served as Chief Executive Officer and a director of the Company since its formation in May 2020 and founded the Company in 2015. He also worked at Kalnin Ventures, the fund manager of BKV O&G, owned by Banpu (SET: BANPU), as Managing Director from June 2014 to May 2020 and Group CEO from January 2019 to May 2020. Prior to that, Mr. Kalnin served in multiple roles at Level 3 Communications, Inc. (“Level 3 Communications”), a global provider of high-capacity communications services to businesses, serving as Vice President of Strategic Business Operations and Planning from January 2014 to June 2014 and Senior Director from February 2012 to December 2013. From January 2010 to July 2011, he served as a Strategy Advisor and Chief of Staff to the Chief Executive Officer at PTT Exploration (SET: PTTEP), a petroleum exploration and production company based in Thailand. Additionally, he served as Engagement Manager at McKinsey & Company, a management consulting firm, from October 2005 to January 2010 and Senior Analyst at Credit Suisse First Boston, the investment banking division of Credit Suisse Group, from July 2000 to July 2003. Mr. Kalnin received a BA in Finance from the University of Western Ontario and an MBA from Northwestern University’s Kellogg School of Management. We believe that Mr. Kalnin’s extensive industry experience and demonstrated leadership capabilities throughout our growth make him qualified to serve on our board of directors.

John T. Jimenez has served as Chief Financial Officer of the Company since April 2021. Prior to joining the Company, he served as Chief Financial Officer of BP Gas and Power Trading Americas and a member of the board of directors of BP Energy Company, a subsidiary of BP (NYSE: BP), from January 2019 to April 2021. Mr. Jimenez also served as interim Chief Executive Officer and a member of the board of directors of VAKT Global Ltd, a venture established by some of the world’s leading energy majors, trading houses and banks to develop a blockchain-based digital platform for post-transaction management of physical energy commodities, from January 2018 to December 2018 and Chairman of the board of directors of VAKT Holdings Ltd from January 2019 to April 2021. Prior to that, he served in various positions at various affiliates of BP, including, most recently, Vice President and Head of IST Global Finance Services from January 2016 to December 2017, Transformation Director from March 2014 to December 2015, Chief of Staff and Vice President of HR Strategy and Planning from May 2012 to March 2014 and Finance Director — Group HR from January 2006 to April 2012. In addition, he has held various leadership roles in international business environments, ranging from start-up operations to corporate head offices, in the US, UK, Mexico, Poland, Bulgaria and India. He has led a range of commercial activities, including large scale transformations, systems implementations, business turnarounds, business start-ups, analytics, strategy and business development. Mr. Jimenez received a BA in Accounting from Saint Mary's University of Minnesota and an MBA from Northwestern University's Kellogg School of Management.

Eric S. Jacobsen has served as Chief Operating Officer of the Company since its formation in May 2020. He also served as Chief Operating Officer of Kalnin Ventures from February 2020 to May 2020. Prior to that, he served as Senior Vice President of Extraction Oil & Gas, Inc. (previously NASDAQ: XOG), an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, from October 2016 to December 2019 and Director of Planning and Development, Director of Exploration and Production and Well Engineering Manager of Noble Energy, Inc. (previously NASDAQ: NBL), an independent energy company engaged in worldwide crude oil and natural gas exploration and production, where he led large-scale shale development efforts of the DJ Basin in Colorado, from January 2011 to October 2016. From June 1993 to January 2011, Mr. Jacobsen worked at BP (NYSE: BP) and its heritage companies, Atlantic Richfield Company and Vastar Resources, Inc., in Montana, Texas, Louisiana, Gulf of Mexico, Algeria, Azerbaijan and other locations and in various positions, including Operations Manager, Offshore Installation Manager and Reservoir Engineer. Mr. Jacobsen received a BS in Environmental Engineering and an MS in Petroleum Engineering from Montana Tech University.

Barry S. Turcotte has served as Chief Accounting Officer of the Company since December 2022. Prior to joining the Company, he most recently served as Senior Vice President and Chief Financial Officer of Crestone Peak Resources, a privately held oil and natural gas company, from May 2017 to November 2021. In addition, Mr. Turcotte served as Chief Accounting Officer of RSP Permian, Inc. (NYSE: RSPP), a publicly listed oil and natural gas company, from April 2014 to May 2017. Prior to that, he served in various positions at Swift Energy Company (NYSE: SFY), a publicly listed oil and natural gas exploration and production company, including Vice President of Accounting and Controller from December 2009 to April 2014, Assistant Controller from April 2005 to November 2009 and other progressive positions of responsibility after joining Swift Energy Company in 2001. He also served in various progressive accounting positions at Westlake Group of Companies, a global chemical manufacturer, from 1995 to 2001. Mr. Turcotte began his career as an auditor in the energy group of Ernst & Young LLP from 1993 to 1995. He has over 30 years of experience in the accounting and finance professions, including in the oil and gas industry. Mr. Turcotte is a Certified Public Accountant and received a BBA from the University of Houston and an Executive MBA from the University of Houston.

Brid C. Kealey has served as Chief Human Resources Officer of the Company since February 2021. Prior to joining the Company, she co-founded and served as Senior Partner of Vector Human Capital Services, a provider of human resources strategy and operational services, from January 2012 to January 2021. In addition, Ms. Kealey served as Chief Human Resources Officer and Vice President, PEO Services of MedSynergies, a provider of business services to Physician Networks, from November 2010 to December 2012 and Chief Learning Officer of Atmos Energy Corporation (NYSE: ATO), a gas utilities company, from March 2009 to May 2010. Previously, she held global human resources leadership roles at Google Inc. (now Alphabet Inc. (NASDAQ: GOOGL, GOOG)) from June 2007 to July 2008, Nokia Corporation (NYSE: NOK) from March 2000 to June 2007 and PepsiCo, Inc. (now NASDAQ: PEP) from 1995 to 2000. Ms. Kealey received a Bachelor of Laws from Trinity College Dublin and a Masters in Business Studies from University College Dublin Michael Smurfit Graduate Business School.

Lindsay B. Larrick has served as Chief Legal Officer of the Company since July 2022 and as Vice President, General Counsel and Corporate Secretary of the Company since its formation in May 2020. She also served as Vice President and General Counsel of Kalnin Ventures from October 2018 to May 2020. Prior to that, she was a partner at national law firms Fox Rothschild LLP from July 2016 to October 2018 and Lathrop & Gage LLP from January 2007 to July 2016. During her time at such law firms, she specialized in the energy practice, served in various management positions, including Chair of the Energy Practice Group for both firms, and gained experience in structuring private equity funds and mergers, acquisitions and divestitures in the oil and gas industry. Ms. Larrick received a BS in Business Administration and a JD from the University of Denver.

Ethan Ngo has served as Chief Technical Services Officer of the Company since July 2022 and, prior to that, as Senior Vice President, Engineering of the Company since its formation in May 2020. He served at Kalnin Ventures as Senior Vice President, Engineering since December 2017 and Vice President, Engineering from March 2015 to December 2017. Prior to that, Mr. Ngo served as A&D Reservoir Engineer of Fidelity Exploration and Production Company, which is involved in the acquisition, exploration, development and production of natural gas and oil resources, from July 2014 to March 2015, Reservoir Engineer of Liberty Resources LLC, a Denver-based private equity backed oil and gas company, from April 2013 to June 2014 and Reservoir Engineer of Newfield Exploration Company (previously NYSE: NFX), an independent energy company, from April 2011 to April 2013. He also served as Senior Reservoir Engineer of ExxonMobil Production Company from February 2008 to March 2011. Mr. Ngo received a BS in Civil Engineering, an MS in International Political Economy and an ME in Petroleum Engineering from the Colorado School of Mines. Mr. Ngo also received an MBA from the University of Colorado, Denver.

Chanin Vongkusolkit has served as Chairman of the Board of the Company since May 2020. He founded Banpu (SET: BANPU) in 1983 and has served as its Chairman of the Board since April 2016. His other positions at Banpu include director and Senior Executive Officer from 2015 to 2016 and director and Chief Executive Officer from 1983 to 2015. In addition, Mr. Vongkusolkit has served as a director of The Erawan Group Public Company Limited (SET: ERW), a hotel investor, developer and operator, since November 2004, and Chairman of its board of directors since April 2018. He has also served as a director of Mitr Phol Sugar Corp., Ltd., a sugar and bio-energy producer, since 1983 and various subsidiaries of Banpu, including Banpu Power (SET: BPP). Additionally, Mr. Vongkusolkit serves as Chairman of the Thai Listed Companies Association and an advisor at the Thammasat Economics Association. He previously served as a Commissioner at the Securities and Exchange Commission of Thailand from 2016 to 2018 and a director of Ratchaburi Electricity Generating Holding Public Company Limited, an independent power producer, from November 2003 to March 2011. Mr. Vongkusolkit received a Bachelor in Economics from Thammasat University and an MBA in Finance from St. Louis University. Mr. Vongkusolkit brings broad expertise in corporate development and leadership to the board of directors. In addition, we believe that Mr. Vongkusolkit's extensive experience with international energy companies makes him qualified to serve on our board of directors.

Somruedee Chaimongkol has served as a director of the Company since May 2020. She has served as a director and Chief Executive Officer of Banpu (SET: BANPU) since May 2015 and a director of BNAC since February 2015. Prior to that, she worked at Banpu as Chief Financial Officer from 2006 to 2015 and Senior Vice President of Finance from 2001 to 2006. In addition, Ms. Chaimongkol has served as a director of various subsidiaries of Banpu, including Banpu Power (SET: BPP). She has also served as a commissioner of PT. Indo Tambangraya Megah Tbk (IDX: ITMG), an Indonesian coal supplier, since March 2022, and served as a director of Biofuel Development Holdings Co., Ltd., from November 2010 to December 2018. Ms. Chaimongkol received a Bachelor's degree in Accounting from Bangkok University. Ms. Chaimongkol brings broad expertise in corporate leadership and financial matters to the board of directors. In addition, we believe that Ms. Chaimongkol's extensive experience as an executive and director at international energy companies makes her qualified to serve on our board of directors.

Joseph R. Davis has served as a director of the Company since May 2020. He has served as a director of Reconnaissance Energy Africa Ltd. d/b/a ReconAfrica (TSXV: RECO), a Canadian oil and gas company engaged in the exploration and development of oil and gas in Mexico, Namibia and Botswana, since January 2022. In 2014, Mr. Davis began working with our Chief Executive Officer, Chris Kalnin, as a consultant, and upon the formation of BKV O&G in June 2015, he assumed the role of Vice President of Geosciences with Kalnin Ventures. He was later promoted to Senior Vice President of Kalnin Ventures, and in January 2019, he became Chief Operating Officer and served in that position until his retirement in March 2020. In addition, he served as Exploration Advisor for Digital Prospectors, LLC, an exploration consulting firm, from May 2009 to May 2015 and Vice President of Hyperion Oil Iraq, L.L.C., an international oil and gas exploration company involved in Iraq and Latin America, from August 2006 to May 2009. From 1992 to 2006, he had a consulting business specializing in evaluation of oil and gas exploration projects.

Mr. Davis received an AB in Earth Science from Dartmouth College, an MS in Geology from Southern Methodist University and a PhD in Geology from the University of Texas at Austin. Mr. Davis brings broad expertise in strategic planning and operations. In addition, we believe that Mr. Davis's upstream industry experience and executive experience make him qualified to serve on our board of directors.

Akaraphong Dayananda has served as a director of the Company since May 2020. He has served as a director and President of BNAC since February 2015. Prior to that, Mr. Dayananda served in various positions at Banpu (SET: BANPU) and Banpu Power (SET: BPP), including a director of Banpu Power from July 2009 to December 2017, Chief Strategy Officer — Head of Strategy and Business Development of Banpu from 2011 to 2019, Senior Vice President — Head of Strategy and Business Development of Banpu from 2006 to 2011, Senior Vice President — Head of Corporate Strategic Planning of Banpu from 1999 to 2006 and Senior Vice President — Finance of Banpu Power from 1997 to 1999. Prior to that, he gained expertise in the financial service sector while serving as Managing Director of Peregrine Nithi Finance and Securities Company Limited from 1995 to 1997 and in various positions at Thai Investment and Securities Plc from 1984 to 1995, including most recently Senior Vice President of Corporate Lending and Marketing. Mr. Dayananda has also served as a director of various subsidiaries of Banpu, both internationally and domestically throughout his career. Mr. Dayananda received a BS in Engineering from Chulalongkorn University and an MBA from Bowling Green State University. He also received certificates in various management and directorship programs, such as the Executive Program in Strategy and Organization from Stanford University and the Director Certificate Program from the Thai Institute of Directors. Mr. Dayananda brings broad expertise in strategic planning, business development and risk management to the board of directors. In addition, we believe that Mr. Dayananda's extensive experience as an executive and director and financial and investment experience make him qualified to serve on our board of directors.

Carla S. Mashinski has served as a director of the Company since September 1, 2022. Since 2019, she has served on the board of directors of Primoris Services Corporation (NASDAQ: PRIM), a specialty construction and infrastructure company in the United States, and has served as chair of its audit committee and a member of its compensation committee since 2021. Ms. Mashinski served as Chief Financial Officer of Cameron LNG, a liquefied natural gas terminal near the Gulf of Mexico, from 2015 to 2017, then was promoted to Chief Financial Officer and Administrative Officer and served in this role until her retirement in May 2022. Prior to that, she served as Chief Financial Officer and Vice President, Finance and Information Management, North American Operations, of Sasol Ltd. (JSE: SOL), an integrated energy and chemical company based in South Africa, from 2014 to 2015, Vice President, Finance and Administration and U.S. Chief Financial Officer of SBM Offshore (AMX: SBMO), a Dutch-based global group of companies servicing the offshore oil and gas industry, from 2008 to 2014 and Vice President, Accounting and Chief Accounting Officer/Controller of GulfMark Offshore, Inc., a global provider of marine transportation services, from 2004 to 2008. Her previous board experience includes serving as a director, and a member of the audit, compensation and nominating committees, of Carbo Ceramics Inc., a technology and services company servicing the oil and gas industry, from 2019 to 2020 and a director, and chair of the compensation committee and member of the audit committee, of Unit Corporation (OTC: UNTC), a diversified energy company, from 2015 to 2020. Ms. Mashinski received a BS in Accounting with high honors from the University of Tennessee at Knoxville and an Executive MBA from the University of Texas at Dallas. She is a Certified Public Accountant in the State of Texas, Certified Management Accountant and Project Management Professional. Ms. Mashinski brings broad experience in financial and accounting matters and corporate governance to the board of directors. In addition, we believe that Ms. Mashinski's financial and accounting experience, U.S. public company board experience and upstream industry experience make her qualified to serve on our board of directors.

Thiti Mekavichai has served as a director of the Company since May 2020. He has served as a director and Chief Executive Officer of BNAC since January 2019 and Head of Oil and Gas Business of Banpu (SET: BANPU) since November 2018. Prior to that, Mr. Mekavichai served as Executive Vice President of Human Resources and Business Services of PTT Exploration (SET: PTTEP) from October 2011 to September 2018 and Executive Vice President of Human Resources of Central Retail Corporation, Thailand's leading multi-format and multi-category retailing platform, from June 2008 to October 2011. From December 1992 to June 2008, he held various technical and human resources positions at subsidiaries of Shell plc (NYSE: SHEL), in both the upstream and downstream industries, and served as a director of Shell Company of Thailand Limited from February 2004 to May 2008. He also served as a director of Energy

Complex Company Limited, a company responsible for the construction and operational management of an office building complex, from April 2012 to August 2018 and PTT Digital Solutions Co., Ltd., an information and communication technology company, from March 2014 to August 2018. Mr. Mekavichai received a BS in Geography from Srinakharinwirot University and a diploma in Hydrographic Surveying from Plymouth Polytechnic, U.K. Mr. Mekavichai brings broad expertise in oil and gas operations, risk management, human resources and corporate development to the board of directors. In addition, we believe that Mr. Mekavichai's extensive experience as an executive and director at international energy companies makes him qualified to serve on our board of directors.

Charles C. Miller III has served as a director of the Company since May 2020. He has served as a director of Global Healthcare Exchange, a provider of exchange and other electronic services to health care providers and their suppliers, since June 2017 and Equideum Health, a Web3 person-centered healthcare and research network provider, since December 2021. Mr. Miller was an executive in the telecommunications industry from 1987 to 2013. From 2000 to 2014, he was Vice Chairman of Level 3 Communications where his responsibilities included corporate strategy, mergers and acquisitions, business development, marketing and information services. Prior to that, Mr. Miller was an executive officer of BellSouth Corporation from 1987 to 2000, where his roles included Senior Vice President, Corporate Strategy and Development, as well as President of BellSouth International, Inc. Before his telecommunications career, he practiced corporate law at King & Spalding LLP from 1979 to 1984 and Ropes & Gray LLP from 1977 to 1979. Mr. Miller received an AB from Harvard College and a JD from Harvard Law School. Mr. Miller brings broad expertise in strategic planning, business development and technology to the board of directors. In addition, we believe that Mr. Miller's U.S. public company board experience and legal expertise make him qualified to serve on our board of directors.

Sunit S. Patel has served as a director of the Company since September 1, 2022. Since February 2021, Mr. Patel has served as Chief Financial Officer of Ibotta, Inc., a consumer technology company. Prior to that, he served as Executive Vice President, Merger and Integration Lead, at T-Mobile US, Inc., a provider of mobile communications services, from October 2018 to April 2020. In addition, Mr. Patel served as Executive Vice President and Chief Financial Officer of CenturyLink, Inc., an international facilities-based communications company, from November 2017 to September 2018 and Executive Vice President and Chief Financial Officer of Level 3 Communications Inc. from 2003 until its merger with CenturyLink in November 2017. He also co-founded and served as Chief Financial Officer of Looking Glass Networks Inc., a facilities-based provider of metropolitan telecommunication transport services, from April 2000 to March 2003. Prior to that, he served in senior leadership positions in a number of telecom companies and began his professional career in investment banking. Mr. Patel received a B.S. in Chemical Engineering and Economics from Rice University and is a Chartered Financial Analyst (CFA). Mr. Patel brings broad experience in financial, accounting and technology matters and strategic planning and transactions to the board of directors. In addition, we believe that Mr. Patel's financial and accounting expertise, executive leadership experience and public company experience make him qualified to serve on our board of directors.

Anon Sirisaengtaksin has served as a director of the Company since May 2020. He has served as a director of Banpu (SET: BANPU) since April 2016 and an Executive Advisor to Banpu for its oil and gas business since 2014. He has also served as a director of Saha-Union Public Company Limited (SET: SUC), an investment company, since January 2020 and CIMB Thai Bank Public Company Limited (SET: CIMBT), a commercial bank in Thailand, since June 2020. In addition, he served as a director and Chief Executive Officer of PTT Global Chemical Public Company Limited (SET: PTTGC) from 2012 to 2013, President and Chief Executive Officer of PTT Exploration (SET: PTTEP) from 2008 to 2012, Senior Executive Vice President, Corporate Strategy and Development of PTT Public Company Limited ("PTT PCL") (SET: PTT) from 2002 to 2008, Executive Vice President, Natural Gas Supply and Trading, Gas Business Group, of PTT PCL from 2001 to 2002 and Deputy President, Natural Gas Marketing and Transmission of PTT Natural Gas Distribution Co., Ltd. from 1996 to 2001. Mr. Sirisaengtaksin received a BS in Geology from Chulalongkorn University and an MBA from Thammasat University. Mr. Sirisaengtaksin brings broad expertise in corporate leadership and strategic planning to the board of directors. In addition, we believe that Mr. Sirisaengtaksin's extensive experience as an executive at international energy companies makes him qualified to serve on our board of directors.

Sinon Vongkusolkit has served as a director of the Company since July 2022. He has served as Chief Executive Officer of Banpu NEXT Co. Ltd. since July 2022. Prior to that, he served at Banpu (SET: BANPU) in the Project Management Office team, where he executed financial and asset transactions, from January 2020 to June 2022. He also served as a financial analyst in the Corporate Finance team of Banpu, where he worked on funding for the Banpu group, from November 2014 to January 2020. Mr. Vongkusolkit received a BA in Business and Marketing Management from Oxford Brookes University and an MA in Global Management Finance from Regent's University London. Mr. Vongkusolkit brings broad expertise in strategic management and operations, including corporate finance, investments and project management, from his time at Banpu to the board of directors. In addition, we believe that Mr. Vongkusolkit's leadership skills, technological adeptness and growth mindset from his time at Banpu NEXT Co. Ltd. make him qualified to serve on our board of directors.

Controlled Company

We have applied to list our common stock on the NYSE under the symbol "BKV." Upon completion of this offering, BNAC will hold approximately % of our total outstanding shares of common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares), comprising more than 50% of the voting power of our outstanding common stock. As a result, we will be a "controlled company" within the meaning of the corporate governance rules of the NYSE. As a "controlled company," we will be eligible to rely on exemptions from the obligation to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of our board of directors consist of independent directors;
- we have a corporate governance and nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These exemptions do not modify the independence requirements for our audit committee. As a controlled company, we will remain subject to the rules of the Sarbanes-Oxley Act and the NYSE that require us to have an audit committee composed entirely of independent directors. Under these rules, we must have at least one independent director on our audit committee by the date our common stock is listed on the NYSE, at least two independent directors on our audit committee within 90 days of the listing date, and at least three independent directors on our audit committee within one year of the listing date. We expect to have three independent directors upon the closing of this offering.

While BNAC continues to control more than 50% of the voting power of our outstanding common stock, we qualify for, and intend to rely on, these exemptions. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

If we cease to be a controlled company within the meaning of the applicable rules of the NYSE, we will be required to comply with these requirements after specified transition periods.

Board of Directors

We currently have eleven directors on our board of directors.

Pursuant to our Stockholders' Agreement, for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that (i) from the completion of this offering until the first anniversary of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. The BNAC designees are Messrs. Kalnin, Davis, C. Vongkusolkit, Dayananda, Mekavichai, Sirisaengtaksin and S. Vongkusolkit and Ms. Chaimongkol.

Our board of directors will be divided into three classes of directors, with each class to be as equal in number as possible, and with the directors serving staggered three-year terms. The term of office of the Class I directors, consisting of Messrs. Kalnin, C. Vongkusolkit and Sirisaengtaksin and Ms. Chaimongkol, will expire at our first annual meeting of stockholders following the completion of this offering. The term of office of the Class II directors, consisting of Messrs. Dayananda, Mekavichai and Patel and Ms. Mashinski, will expire at our second annual meeting of stockholders following the completion of this offering. The term of office of the Class III directors, consisting of Messrs. Davis, Miller and S. Vongkusolkit, will expire at our third annual meeting of stockholders following the completion of this offering. See "*Description of Capital Stock — Anti-Takeover Provisions — Classified Board of Directors*" for more information.

Director Independence

Upon completion of this offering, three members of our board of directors will qualify as "independent" under the listing standards of the NYSE. Our board of directors has determined that each of Messrs. Miller and Patel and Ms. Mashinski is independent as defined under the NYSE corporate governance standards.

Committees of the Board of Directors

Our board of directors will establish standing committees in connection with the discharge of its responsibilities. Upon the completion of this offering, these committees will include an Audit & Risks Committee, a Compensation Committee and a Nominations & Governance Committee. The composition and responsibilities of each of the committees of our board of directors are described below. Members will serve on these committees until their resignation or until as otherwise determined by our board of directors.

Audit & Risks Committee

The Audit & Risks Committee will oversee the conduct of our financial reporting processes, including (i) reviewing with management and the outside auditors the audited financial statements included in our annual reports filed with the SEC, (ii) reviewing with management and the outside auditors the interim financial results included in our quarterly reports filed with the SEC, (iii) discussing with management and the outside auditors the quality and adequacy of internal controls and (iv) reviewing the independence of the outside auditors.

Our Audit & Risks Committee will have a minimum of three members. Upon the completion of this offering, we expect the members of our Audit & Risks Committee will be Ms. Mashinski, Ms. Chaimongkol and Mr. Patel, and Ms. Mashinski will serve as the chair of the Audit & Risks Committee. All members of our Audit & Risks Committee will be "independent" as defined in the NYSE corporate governance standards and Rule 10A-3 of the Exchange Act. All members of our Audit & Risks Committee will, in the judgment of our board of directors, be financially literate, or become so within a reasonable period of time after appointment to the Audit & Risks Committee, and at least one member of the Audit & Risks Committee will qualify as an "audit committee financial expert" as defined under the Sarbanes-Oxley Act and applicable SEC regulations. The Audit & Risks Committee will operate under a written charter that satisfies the applicable rules and regulations of the SEC and the listing standards of the NYSE, and the Audit & Risks Committee will review the charter annually. A copy of the Audit & Risks Committee Charter will be available for review on the Company's website.

Nominations & Governance Committee

The Nominations & Governance Committee will be responsible for (i) advising our board of directors about the appropriate composition of our board of directors and its committees, (ii) identifying and evaluating candidates for board service, (iii) recommending director nominees for election at annual meetings of stockholders or for appointment to fill vacancies and newly created directorships, and (iv) recommending the directors to serve on each committee of our board of directors. The Nominations & Governance Committee will also be responsible for periodically reviewing and making recommendations to our board of directors regarding corporate governance policies and responses to stockholder proposals, for conducting an annual performance review of our board of directors and its committees, and for reviewing whether our directors satisfy applicable independence requirements. Pursuant to our Stockholders' Agreement, BNAC, through ownership interests in us held by BNAC and its affiliates, will have certain rights to designate individuals for nomination to our board of directors, subject to applicable corporate governance rules of the SEC and the NYSE (which may require BNAC to designate independent directors). See "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*."

Upon the completion of this offering, we expect the members of our Nominations & Governance Committee will be Messrs. Sirisaengtaksin, Davis, Dayananda and Mekavichai, and Mr. Sirisaengtaksin will serve as the chair of the Nominations & Governance Committee. As a "controlled company," our Nominations & Governance Committee is not required to be comprised of entirely independent directors. The Nominations & Governance Committee will operate under a written charter that satisfies the applicable rules and regulations of the SEC and the listing standards of the NYSE, and the Nominations & Governance Committee will review the charter annually. A copy of the Nominations & Governance Committee Charter will be available for review on the Company's website.

Compensation Committee

The Compensation Committee will review, evaluate and recommend to our board of directors compensation policies with respect to our directors, executive officers and senior management. The Compensation Committee will also administer the 2022 Plan. The Compensation Committee will have the authority to approve the compensation of the directors, executive officers and senior management of the Company. The Compensation Committee will also have the authority to grant equity awards under the 2022 Plan.

Upon the completion of this offering, we expect the members of our Compensation Committee will be Ms. Chaimongkol, Ms. Mashinski and Mr. Miller, and Ms. Chaimongkol will serve as the chair of the Compensation Committee. As a "controlled company," our Compensation Committee is not required to be comprised of entirely independent directors. The Compensation Committee will operate under a written charter that satisfies the applicable rules and regulations of the SEC and the listing standards of the NYSE, and the Compensation Committee will review the charter annually. A copy of the Compensation Committee Charter will be available for review on the Company's website.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve on the board of directors or compensation committee of another public company that has an executive officer that serves on our board or compensation committee. No member of our board is an executive officer of another public company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

Code of Business Conduct and Ethics

Upon the completion of this offering, our board of directors will adopt a new Code of Business Conduct and Ethics applicable to all the Company's employees, officers and directors. The Code of Business Conduct and Ethics will cover compliance with law; fair and honest dealings with the Company, its competitors and others; full, fair and accurate disclosure to the public; and procedures for compliance with the Code of Business Conduct and Ethics. This Code of Business Conduct and Ethics will be available on the Company's website.

Corporate Governance Guidelines

Upon the completion of this offering, our board of directors will adopt corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

EXECUTIVE COMPENSATION

This section describes the material elements of compensation awarded to, earned by or paid to the following named executive officers (our "NEOs") for calendar years 2022 and 2021:

- Christopher P. Kalnin, Chief Executive Officer and interim Chief Financial Officer
- John T. Jimenez, Chief Financial Officer
- Eric S. Jacobsen, Chief Operating Officer

Summary Compensation Table

Name and Position (as of December 31, 2022)	Year	Salary ($)	Bonus ($)[(1)]	Stock awards ($)[(2)]	Nonequity incentive plan compensation ($)[(3)]	All other compensation ($)[(4)]	Total ($)
Christopher Kalnin	2022	510,000	—	—	800,700	18,383	1,329,083
Chief Executive Officer[(5)]	2021	501,923	—	16,896,074	795,000	11,928	18,204,925
John Jimenez	2022	357,000	—	—	210,183	18,376	585,559
Chief Financial Officer[(6)]	2021	250,385	250,000	8,009,952	120,204	31,339	8,661,880
Eric Jacobsen	2022	412,000	—	—	223,159	18,383	653,542
Chief Operating Officer	2021	401,539	—	9,591,205	224,190	22,340	10,239,274

(1) Amount represents the one-time sign-on bonus paid to Mr. Jimenez in 2021 in connection with the commencement of his employment.

(2) Amounts reported represent the aggregate grant date fair value of TRSUs and PRSUs under the 2021 Plan, computed in accordance with FASB ASC 718. Each of Messrs. Kalnin's, Jimenez's and Jacobsen's PRSUs were granted in 2021. Under the 2021 Plan, TRSUs are expected to be granted in four annual grants over a four-year period. For each of Messrs. Kalnin, Jimenez and Jacobsen, the first annual grant of TRSUs was made in 2021, the second annual grant of TRSUs was made in 2022 and the third annual grant of TRSUs for Messrs. Kalnin and Jacobsen was made in January 2023. In accordance with FASB ASC 718, for accounting purposes, the Company recognized a compensation expense in 2021 for each of the four annual grants expected to be granted during the four-year period, although only the first annual grant was granted in 2021. Therefore, in 2021, the grant date fair value of the TRSUs reflects not only the TRSUs granted in 2021, but also the TRSUs that were expected to be granted, and have since actually been granted in 2022 and, for Messrs. Kalnin and Jacobsen, in 2023, and the grant date fair value of the TRSUs that were expected to be granted in 2024, subject to the continuation of the 2021 Plan and continued employment through each such anticipated grant date, in addition to other factors. For more details relating to the assumptions used in calculating the grant date fair value of the TRSUs and PRSUs reported in this column, including modifications made thereto in November 2021, see "*Note 12 — Equity-Based Compensation*" to our audited consolidated financial statements included elsewhere in this prospectus. The grant date fair value for the PRSUs reflected in this table are reported based upon the probable outcome of the performance conditions as of the grant date, and were $12,570,730, $5,959,428 and $7,135,885 for Messrs. Kalnin, Jimenez and Jacobsen, respectively, which amounts are the sum of the original grant date fair value of the PRSUs, assuming a stock price of $10.00 per share and assumptions made with respect to the achievement of the performance goals at that time, plus the incremental cost associated with a modification made to the awards in November 2021, assuming a stock price of $11.06 per share and changes to the assumptions made with respect to the achievement of the performance goals as of the date of modification. The value of the PRSUs granted in 2021, assuming achievement of the maximum performance would have been as follows: Mr. Kalnin: $20,184,942; Mr. Jimenez: $12,029,741; Mr. Jacobsen: $14,404,544, which amounts are the sum of the original grant date fair value of the PRSUs, assuming a stock price of $10.00 per share, plus the incremental cost associated with a modification made to the awards in November 2021, assuming a stock price of $11.06 per share.

(3) Amounts reported represent each NEO's annual performance-based bonus earned in 2021 and 2022 but paid after the end of the fiscal year, upon certification of the applicable performance measures by our Compensation Committee. See "— *Annual Performance-Based Bonuses*" for more information.

(4) Amounts reported include the amounts paid to the NEOs shown in the following table:

	Company 401(k) Contribution ($)[(a)]	Life Insurance Premiums ($)[(b)]
Christopher P. Kalnin	18,323	60
John T. Jimenez	18,316	60
Eric S. Jacobsen	18,323	60

(a) The Company maintains a 401(k) plan that provides employees with an opportunity to save for retirement. The Company makes matching contributions of up to 6% of base salary, which contributions are immediately vested.

(b) Included in this column are the life insurance premiums paid on behalf of each NEO.

(5) Mr. Kalnin served as the Company's interim Chief Financial Officer from July 2020 until Mr. Jimenez assumed the role in April 2021. Mr. Kalnin was not separately compensated for his position as interim Chief Financial Officer.

(6) Mr. Jimenez assumed the role of Chief Financial Officer on April 16, 2021, and thus, in 2021, his base salary and non-equity incentive plan compensation information reflects only the period from April 16, 2021 through December 31, 2021.

Employment Agreements

CEO Employment Agreement

Mr. Kalnin and the Company entered into an employment agreement effective as of August 4, 2020 (the "CEO Employment Agreement"), which provides Mr. Kalnin with, among other things, (1) an annual base salary of $500,000, subject to annual review by our board of directors, which, following such review was increased in 2022 to $510,000, (2) the eligibility to receive an annual cash bonus, with target payment equal to 100% of his base salary, but paid at an amount commensurate with the level at which the applicable performance goals are achieved (which may be higher or lower than the target level) and subject to continued employment through the end of the year, and (3) the opportunity to participate in the Company's equity incentive plan, with an annual restricted stock unit ("RSU") award to be made in each of 2020, 2021, 2022 and 2023 (each an "Annual RSU Grant") that is equal to, at least 325,900 RSUs per year; subject to the terms of the applicable plan. Mr. Kalnin's Annual RSU Grant has been satisfied in accordance with the 2021 Plan, by reference to Mr. Kalnin's four-year Annual RSU Grant opportunity, granted approximately 70% on January 1, 2021 in the form of PRSUs and the remaining 30% in TRSUs, the first, second and third annual grants of which were granted on each of January 1, 2021, January 1, 2022 and January 1, 2023. Each of the TRSU annual grants are subject to vesting requirements once granted, as described in more detail below in "— *Equity Awards Granted Under Our 2021 Long Term Incentive Plan*" and "— *Outstanding Equity Awards at Fiscal Year-End*." Mr. Kalnin is also eligible to participate in and receive benefits offered to our employees, including paid and holiday time off, health insurance coverage and participation in our 401(k) plan. Mr. Kalnin is subject to customary confidentiality and invention assignment covenants, as well as non-competition and non-solicitation covenants which extend for 18 months after termination of employment. Additionally, Mr. Kalnin may receive compensation and benefits in connection with a termination of his employment or a change in control, which are discussed below in "— *Potential Payments Upon Termination or Change in Control — Separation Benefits in the CEO Employment Agreement*."

CFO Employment Agreement

Mr. Jimenez and the Company entered into an employment agreement effective as of January 11, 2021 (the "CFO Employment Agreement"), pursuant to which Mr. Jimenez assumed the role of the Company's Chief Financial Officer as of April 16, 2021 and which provides Mr. Jimenez with, among other things, (1) an annual base salary of $350,000, which was increased in 2022 to $357,000, (2) the opportunity to receive a discretionary annual cash bonus based on the Company's performance (and taking into account Mr. Jimenez's individual effort and satisfactory achievement of established performance goals) in an amount between 0% and 60% of his base salary, and (3) the opportunity to participate in the 2021 Plan, which was originally estimated to equate to equity awards with respect to approximately 618,000 shares over a four-year period and, which would be subject to the terms of the 2021 Plan and ultimately dependent based on Company performance and Mr. Jimenez's individual effort and satisfactory achievement of performance goals. The CFO Employment Agreement provided Mr. Jimenez with a one-time singing bonus of $250,000 in connection with the commencement of his employment with the Company and the payment of Mr. Jimenez's relocation expenses, up to a maximum of $30,000, incurred in connection with his relocation to the Denver, Colorado area. Mr. Jimenez is also eligible to participate in and receive benefits offered to other employees, including paid and holiday time off, health insurance coverage and participation, with a company match, in our 401(k) plan. Mr. Jimenez is subject to customary confidentiality and invention assignment covenants, as well as non-disparagement, non-competition and non-solicitation covenants which extend for 12 months after termination of employment. Additionally, Mr. Jimenez may receive compensation in connection with a termination of his employment, which is discussed below in "— *Potential Payments Upon Termination or Change in Control — Separation Benefits in the CFO Employment Agreement*."

COO Employment Agreement

Mr. Jacobsen and Kalnin Ventures entered into an employment agreement effective as of February 18, 2020 (the "COO Employment Agreement"), which provides Mr. Jacobsen with, among other things, (1) an annual base salary of $400,000, which was increased in 2022 to $412,000, and (2) the opportunity to receive a discretionary annual cash bonus based on the Company's performance (and taking into account Mr. Jacobsen's individual effort and satisfactory achievement of established performance goals) in an amount between 0% and 40% of his base salary. Mr. Jacobsen is also eligible to participate in and receive benefits offered to other employees, including paid and holiday time off, health insurance coverage and participation, with a company match, in our 401(k) plan. Mr. Jacobsen is subject to customary confidentiality and invention assignment covenants, as well as non-disparagement, non-competition and non-solicitation covenants. Additionally, Mr. Jacobsen may receive compensation in connection with a termination of his employment, which is discussed below in "— *Potential Payments Upon Termination or Change in Control — Separation Benefits in the COO Employment Agreement*."

Equity Awards Granted Under Our 2021 Long Term Incentive Plan

During the years ended December 31, 2021 and December 31, 2022, RSU awards were granted to our NEOs under the 2021 Plan, some of which are subject to service-based vesting conditions and some of which are subject to both performance-based and service-based vesting conditions. On January 1, 2021, Mr. Kalnin and Mr. Jacobsen were granted 97,770 and 55,500 TRSUs, respectively, and 912,520 and 518,000 PRSUs at the target payout level (which equate to 1,825,040 and 1,036,000 PRSUs at maximum payout level), respectively. On April 16, 2021, Mr. Jimenez was granted 46,350 TRSUs and 432,600 PRSUs at the target payout level (which equates to 865,200 PRSUs at maximum payout level). Approximately 25% of Messrs. Kalnin's and Jacobsen's TRSUs were vested at the time of grant and an additional 25% vested on each of January 1, 2022 and January 1, 2023, with the remainder set to vest on January 1, 2024, subject to continued employment through such vesting date. Approximately 25% of Mr. Jimenez's TRSUs were vested at the time of grant and an additional 25% vested on April 16, 2022, with the remainder set to vest in two substantially equal tranches on each of April 16, 2023 and April 16, 2024, in each case, subject to continued employment through such applicable vesting date. Messrs. Kalnin's, Jacobsen's and Jimenez's PRSUs will vest based upon the level at which the performance measures described below in "— *BKV Corporation 2021 Long Term Incentive Plan*" are achieved over the period beginning January 1, 2021 and ending on the earliest of December 31, 2023, an IPO or Change in Control of the Company (each as defined in the 2021 Plan), so long as each of Messrs. Kalnin, Jacobsen and Jimenez remain employed by the Company through the end of such performance period.

On January 1, 2022, Messrs. Kalnin and Jacobsen were granted 97,700 and 55,500 TRSUs respectively, and on April 16, 2022, Mr. Jimenez was granted 46,350 TRSUs. Approximately 25% of Messrs. Kalnin's and Jacobsen's TRSUs were vested at the time of grant and an additional 25% vested on January 1, 2023, with the remainder set to vest in two substantially equal tranches on each of January 1, 2024 and January 1, 2025, in each case, subject to continued employment through such applicable vesting date. Approximately 25% of Mr. Jimenez's TRSUs were vested at the time of grant, with the remainder set to vest in three substantially equal tranches on each of April 16, 2023, April 16, 2024 and April 16, 2025, in each case, subject to continued employment through such applicable vesting date.

Annual Performance-Based Bonuses

For 2021 and 2022, our Compensation Committee recommended and our board of directors approved the adoption of an annual, performance-based bonus program for all of our employees, including each of our NEOs (the "2021 Annual Bonus" and the "2022 Annual Bonus," respectively, and collectively, the "Annual Bonuses"). Messrs. Kalnin, Jimenez and Jacobsen were assigned a target bonus opportunity for each of their Annual Bonuses equal to, for Mr. Kalnin, 100% of his base salary and for Messrs. Jimenez and Jacobsen, 30% of each of their respective base salaries. Each NEO's 2021 Annual Bonus and 2022 Annual Bonus was calculated by multiplying the individual's base salary by his target bonus opportunity and multiplied by an additional two components: the corporate multiplier, based on corporate performance goals, which were based off of the KPI Scorecard (discussed below) for the applicable year, and an individual multiplier, based on individual performance goals determined by, for Mr. Kalnin, the board of directors and for Messrs. Jimenez and Jacobsen, Mr. Kalnin, subject to approval by our board of directors, for each applicable year. Once both the corporate performance goals and the individual performance goals were scored and the corporate multiplier and individual multipliers were determined for the applicable year, the 2021 Annual Bonus and 2022 Annual Bonus earned by each of Messrs. Kalnin, Jimenez and Jacobsen were equal to the product of their respective target bonus opportunities and the corporate multiplier and individual multiplier assigned to the corporate performance goals and individual performance goals, respectively. Mr. Jimenez's 2021 Annual Bonus was prorated to reflect the number of full months worked during 2021.

Company Performance Measures

The company performance metrics are based on the "KPI Scorecard," which, for the 2021 Annual Bonus, evaluated "lagging" indicators and "leading" indicators that were weighted at an aggregate of 70% and 30%, respectively, and for the 2022 Annual Bonus, evaluated "lagging" indicators, "leading" indicators and "ESG" indicators that were weighted at an aggregate of 40%, 30% and 30%, respectively. In 2022, the "ESG" indicator was added to emphasize the Company's prioritization of the alignment of ESG and EHSR to the Company's core values.

For the 2021 Annual Bonus, the "lagging" indicators measured the Company's key financial and operation metrics, including the Company's EBITDA, net income, free cash flow, net production, year-end reserves, break-even unit costs, costs of upstream subsurface development and environmental health safety and regulatory measures. Each of these metrics comprised between 5% and 20% of the overall "lagging" indicator category. The "leading" indicators measured the Company's achievement of strategic and business plan goals, including employee engagement, baseline ESG scores as measured by a third-party consultant, the successful completion of the integration of the Devon Barnett Acquisition, the number of acquisition opportunities identified by the Company, the Company's automation and use of big data tools, the process redesign implementation of EHSR and operations, the achievement of midstream projects, enhancements in the Company's value chain and the level at which future projects inventory is clearly planned, each weighted equally at 10%.

The Compensation Committee determined that the "lagging" indicators, or the financial and operational metrics were met, in the aggregate, at 160% of target, resulting in a company multiplier of 1.12 (or the product of the 160% level of achievement and the 70% weighting of such metrics). The Compensation Committee determined that the "leading" indicators, or the Company's strategic goals, were met, in the aggregate, at 184% of target, resulting in a company multiplier of 0.55 (or the product of the 184% level of achievement and the 30% weighting of such metrics). These determinations would have resulted in a total company multiplier equal to 1.67. However, the Compensation Committee included in its analysis of the Company's performance during 2021 that, while not costs that affected the level at which the performance metrics of the KPI Scorecard were met, there were nonetheless certain other costs that affected the Company. As a result of these costs and in the Compensation Committee's discretion to determine the level at which the performance metrics of the KPI Scorecard were achieved, the Compensation Committee determined that the overall company multiplier should be lowered by approximately 5%, resulting in a company multiplier equal to 1.59.

For the 2022 Annual Bonus, the “lagging” indicators measured the Company’s shareholder value metrics, including the Company’s EBITDA, net income, free cash flow, break-even unit costs, and the total net income related to the BKV-BPP Power Joint Venture. Each of these metrics comprised between 15% and 30% of the overall “lagging” indicator category. The “leading” indicators measured the Company’s achievement of operational and strategic goals, including its net revenue interests production, estimated proved reserves at SEC Pricing, operational excellence (including the performance of its drilling and completion and restimulation programs and the level at which future projects inventory is clearly planned), the number of acquisition opportunities identified by the Company, the Company’s automation and use of big data tools, and margin expansion through the use of daily pricing, hedges, storage sales and other means. Each of these metrics are weighted between 9% and 26% of the overall “leading” indicator category. The “ESG” indicators measured the Company’s EHSR and ESG performance, including its Total Recordable Incident Rate (TRIR), major incidents, notices of violations (NOVs) from current year activity that could carry a penalty or fine, employee engagement, progress towards emission reduction targets, the satisfaction of three key goals derived from the 2021 employee engagement survey, the Company’s performance of its ESG goals (including its MSCI ESG rating, completion of its sustainability report and the initiation of RSG sales), and reaching FID on a CCUS project. Each of these metrics are weighted between 10% and 38% of the overall “ESG” indicator category.

The Compensation Committee determined that the Company’s shareholder value metrics were met, in the aggregate, at 161% of target, resulting in a company multiplier of 0.64 (or the product of the 161% level of achievement and the 40% weighting of such metrics). The Compensation Committee determined that the Company’s operational and strategic goal metrics were met, in the aggregate, at 138% of target, resulting in a company multiplier of 0.41 (or the product of the 138% level of achievement with the 30% weighting of such metrics).The Compensation Committee determined that “ESG” indicators were met, in the aggregate at 171%, resulting in a company multiplier of 0.52 (or the product of the 171% level of achievement and the 30% weighting of such metrics). These determinations resulted in a company multiplier equal to 1.57.

Individual Performance Measures

For both the 2021 Annual Bonus and the 2022 Annual Bonus, the Compensation Committee set Mr. Kalnin’s individual performance measures to be the same as the KPI Scorecard used for the company performance measures. The Compensation Committee determined for both the 2021 Annual Bonus and the 2022 Annual Bonus that Mr. Kalnin’s individual contributions to the KPI Scorecard, along with his guiding the Company to be ready for an IPO and the Company’s employee satisfaction (measured through a survey of the employees) resulted in an individual multiplier of 1.00, which the board of directors approved.

Mr. Kalnin set Messrs. Jimenez’s and Jacobsen’s individual performance goals for both of their 2021 Annual Bonus and 2022 Annual Bonus to be based off the elements of the KPI Scorecard that directly related to each of their duties. For Mr. Jimenez’s 2021 Annual Bonus and 2022 Annual Bonus, Mr. Jimenez’s individual performance goals included his leadership, people and culture skills, his finance and accounting foundational processes and his IPO readiness. With respect to Mr. Jimenez’s 2021 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on the strong relationships Mr. Jimenez built with investors, his ability to address audit issues and his engagement of Deloitte to define strategy and baseline readiness, and to prepare a plan for the Company’s IPO, Mr. Jimenez’s individual multiplier should be 1.080, which the board of directors approved. With respect to Mr. Jimenez’s 2022 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on growth of the finance and accounting teams, IPO readiness, the development of relationships with investors and financial institutions, Mr. Jimenez’s individual multiplier should be 1.25, which the board of directors approved. For Mr. Jacobsen’s 2021 Annual Bonus and 2022 Annual Bonus, Mr. Jacobsen’s individual performance goals included his leadership, people and culture skills, his ESG foundations and his IPO readiness, and additionally for his 2022 Annual Bonus, growth of the CCUS business. With respect to Mr. Jacobsen’s 2021 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on the strong leadership skills Mr. Jacobsen showed in both internal and external collaboration, his defined ESG strategy and implementation and his operations preparedness for an

IPO in 2022, Mr. Jacobsen's individual multiplier should be 1.175, which the board of directors approved. With respect to Mr. Jacobsen's 2022 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on growth of the CCUS business, development of the data analysis program, successful M&A integration and an award-winning sustainability report, Mr. Jacobsen's individual multiplier should be 1.15, which the board of directors approved.

Outstanding Equity Awards at Fiscal Year-End

	Stock Awards			
Name	**Number of shares or units of stock that have not vested (#)**	**Market value of shares or units of stock that have not vested ($)**	**Equity incentive plan awards: Number of unearned shares, units or other rights that have not vested (#)**	**Equity incentive plan awards: Market or payout value of unearned shares, units or other rights that have not vested ($)**
Christopher P. Kalnin	—	—	912,520(1)	13,477,920
Christopher P. Kalnin	73,328(2)	1,083,055	—	—
Christopher P. Kalnin	48,886(3)	722,046	—	—
John T. Jimenez	—	—	432,600(1)	6,389,502
John T. Jimenez	34,763(4)	513,450	—	—
John T. Jimenez	23,176(5)	342,310	—	—
Eric S. Jacobsen	—	—	518,000(1)	7,650,860
Eric S. Jacobsen	41,625(2)	614,801	—	—
Eric S. Jacobsen	27,750(3)	409,868	—	—

(1) Represents the target number of PRSUs outstanding as of December 31, 2022 (assuming the performance goals are determined to be met at target). The number of PRSUs outstanding (and the value thereof), as of December 31, 2022 assuming the performance goals are determined to be met at maximum was 1,825,040 (or $26,955,841); 865,200 (or $12,799,004); and 1,036,000 (or $15,301,720) for Messrs. Kalnin, Jimenez and Jacobsen, respectively.

(2) Represents the portion of the TRSUs granted on January 1, 2022 to Messrs. Kalnin and Jacobsen that remained outstanding and unvested as of December 31, 2022, approximately one-third of which vested or vest, as applicable, on each of January 1, 2023, January 1, 2024 and January 1, 2025.

(3) Represents the portion of the TRSUs granted on January 1, 2021 to Messrs. Kalnin and Jacobsen that remained outstanding and unvested as of December 31, 2022, approximately one-half of which vested or vest, as applicable, on each of January 1, 2023 and January 1, 2024.

(4) Represents the portion of the TRSUs granted on April 16, 2022 to Mr. Jimenez that remained outstanding and unvested as of December 31, 2022, approximately one-third of which vest on each of April 16, 2023, April 16, 2024 and April 16, 2025.

(5) Represents the portion of the TRSUs granted on April 16, 2021 to Mr. Jimenez that remained outstanding and unvested as of December 31, 2022, approximately one-half of which vest on each of April 16, 2023 and April 16, 2024.

Potential Payments Upon Termination or Change in Control

Separation Benefits in the CEO Employment Agreement

The CEO Employment Agreement provides that, if Mr. Kalnin's employment with the Company is terminated by the Company without "cause" or by Mr. Kalnin with "good reason," (1) any outstanding RSUs granted pursuant to his Annual RSU Grant will become vested and (2) Mr. Kalnin will receive a lump sum payment equal to 200% of the sum of (a) his base salary plus (b) his target annual cash bonus, each in effect at the time of Mr. Kalnin's termination. If Mr. Kalnin elects coverage under the Company's medical plan pursuant to COBRA, Mr. Kalnin will be reimbursed for the full amount of his and his eligible dependents' COBRA premiums for the 18-month period following his termination, unless he earlier becomes eligible for coverage under another employer's medical plan (together with the Annual RSU Grant acceleration and lump sum payment, the "CEO Separation Benefits"). "Cause," as defined in the CEO Employment Agreement, means Mr. Kalnin's (i) indictment for a felony or his commission of fraud against the Company; (ii) misconduct that brings the Company into substantial public disgrace or disrepute; (iii) gross negligence or gross misconduct with respect to the Company; (iv) insubordination to, or material failure to follow lawful directions of, the board of directors, in either case if not cured within 10 days of Mr. Kalnin's receipt of written notice of such event; (v) material violation of the restrictive covenants in the CEO Employment Agreement; (vi) material breach of any a Company work rule or internal policy that is not cured within 10 days of Mr. Kalnin's receipt of written notice of such event (if such event can be cured); (vii) a violation of the Foreign Corrupt Practices Act of 1977 or any state or federal anti-money laundering laws; or (viii) material breach of the CEO Employment Agreement that is not cured within 30 days of Mr. Kalnin's receipt of written notice of such breach. "Good Reason," as defined in the CEO Employment Agreement, means (i) a material reduction in Mr. Kalnin's base salary or target annual bonus (other than as part of an across-the board reduction of no more than 10% applicable to all of the Company's executives); (ii) a material diminution in Mr. Kalnin's position, duties, authority, reporting or responsibilities; (iii) the Company's material breach of the CEO Employment Agreement; or (iv) the involuntary permanent relocation of Mr. Kalnin's principal place of business to a location more than 35 miles beyond the Company's current place of business.

Mr. Kalnin's receipt of the CEO Separation Benefits is subject to his execution and non-revocation of a release of claims in favor of the Company and his continued compliance with the restrictive covenants contained in the CEO Employment Agreement. Such restrictive covenants include non-competition, non-solicitation (of both employees or customers) and intellectual development prohibitions for 18 months following termination, along with a perpetual confidentiality prohibition.

Separation Benefits in the CFO Employment Agreement

The CFO Employment Agreement provides that, if Mr. Jimenez's employment with the Company is terminated by the Company without "cause" (as defined in the CFO Employment Agreement), Mr. Jimenez will receive 18 months of base salary, subject to his execution of a separation agreement and general release and his compliance with a 12 month non-competition and non-solicitation restriction.

Separation Benefits in the COO Employment Agreement

The COO Employment Agreement provides that, if Mr. Jacobsen's employment with the Company is terminated by the Company without "cause" (as determined by the Company in good faith), Mr. Jacobsen will receive a lump sum payment equal to three months of his base salary.

BKV Corporation 2021 Long Term Incentive Plan

The 2021 Plan was initially adopted by our board of directors on January 1, 2021 and was amended in November 2021. The 2021 Plan will be terminated by the board of directors in connection with this offering.

Purpose. The purpose of the 2021 Plan was to permit the grant of awards to our directors and employees of our Company or any of our subsidiaries, and to attract and retain such individuals who contribute to the achievement of the Company's economic objectives.

Administration. Our 2021 Plan was administered by our Compensation Committee (for purposes of this section, the "Committee") and subject to the board of director's approval. Subject to the terms of the 2021 Plan, the administrator had the authority to, among other things, select the persons to whom awards are granted, determine the nature, extent and timing of the awards to be granted, determine the duration of and restrictions and other conditions applicable to such awards. Any interpretation or determination by the Committee under the 2021 Plan will be final and conclusive. The Committee may delegate its administrative duties or powers to one or more of our officers.

Shares Available. There were 14,941,176 shares of our common stock authorized for grant under the 2021 Plan. The shares available for issuance may be shares authorized but unissued or treasury shares. The

Chief Executive Officer had the authority to grant up to 60% of the available shares on or before December 31, 2022 (assuming target payout of the PRSUs). Assuming maximum payout of the PRSUs and based on the TRSUs that were legally outstanding as of December 31, 2022, 12,600,740 shares were underlying outstanding equity awards and 916,119 shares remained available for issuance under the 2021 Plan.

Share Counting. The aggregate number of shares of our common stock that were available for award under the 2021 Plan were reduced by one share of our common stock for every one share of our common stock subject to an award granted under the 2021 Plan. Shares of our common stock that were subtracted from the amount of available shares with respect to an award that ultimately lapsed, expired, was forfeited or for any reason was terminated or unvested were not automatically available again for issuance under the 2021 Plan.

Eligibility. Awards under the 2021 Plan could be granted to employees and directors of the Company or any of our subsidiaries. Eligible recipients who were either (1) the Chief Executive Officer or classified by the Company at the Senior Management level (those reasonably likely to be in the four most highly compensated during the next financial year or otherwise recommended by the Chief Executive Officer and approved by the board of directors as such) or (2) classified by the Company below the Senior Management level but who were recommended for an award by our Chief Executive Officer generally received PRSUs and TRSUs under the 2021 Plan.

Types of Awards Under the 2021 Plan. Pursuant to the 2021 Plan, we could grant TRSUs and PRSUs. Generally, with respect to the aggregate awards anticipated to be granted to participants over a four-year period, 70% of such aggregate award granted under the 2021 Plan were PRSUs and 30% were TRSUs.

Time-Vested Restricted Stock Units. The TRSUs were contemplated as being granted annually beginning on the effective date of the 2021 Plan and in each of the three (3) financial years thereafter or commencing upon an individual first becoming a participant under the 2021 Plan. The TRSUs were subject to the recipient's continued employment and are 25% vested on grant, with the remaining TRSUs vesting 25% on each of the first, second and third anniversaries of grant.

Performance-Vested Restricted Stock Units. The PRSUs were granted as a one-time grant on the effective date of the 2021 Plan or upon an individual first becoming a participant under the 2021 Plan. The PRSUs vest subject to the recipient's continued performance through the vesting date and based upon the level at which the performance metrics are attained, which metrics may be attained at a level between 0% and 100% of the maximum performance level. The performance period for the PRSUs began on the effective date of the 2021 Plan and will end on the earliest of December 31, 2023, the date of an IPO or the date of a Change in Control (as defined in the 2021 Plan), which means that the performance period will end in connection with the completion of this offering. The performance measures include total shareholder return, return on capital employed and the Company's IPO readiness.

Effect of Termination or Forfeiture. Unless otherwise provided in an award agreement, or unless the Committee determines otherwise, upon a participant's termination for any reason, awards held by the participant that have not vested as of the date of his or her termination were forfeited. If the Committee determines that the participant has committed an act that would constitute cause or an adverse action (each as defined in the 2021 Plan), either before or after such participant's termination of employment and regardless of whether such participant was terminated for cause, the Committee in its sole discretion may require that the participant surrender and return to the Company all or any shares of common stock received prior to his or her termination in settlement of any vested award under the 2021 Plan or to disgorge all or any profits or any other economic value made or realized by the participant, during the period beginning one year before the participant's termination in connection with any shares of stock issued upon vesting of any TRSUs and PRSUs granted under the 2021 Plan.

Repurchase, Put and Drag-Along Rights. If a participant (1) committed a material breach of his or her employment agreement or service contract with the Company that was not capable of being remedied or, if capable of being remedied, that was not remedied by the participant within 30 days, or (2) was terminated for any reason, then the Company had the right, which remained open for 90 days following termination, to repurchase all (but not less than all) of the vested shares of common stock acquired by the participant under the 2021 Plan. The purchase price of the vested shares so repurchased was equal to the fair market value of the shares at the time of repurchase. Prior to this offering, if a participant's employment was terminated for any reason other than the participant's resignation or, if a participant's employment terminated due to his or her voluntary resignation and more than 36 months had passed since the participant's first grant of an incentive award under the 2021 Plan, and, in each case, the Company had not repurchased the participant's shares of common stock acquired under the 2021 Plan, the participant had the right to elect to sell such shares back to the Company at an amount equal to the fair market value of the shares at the time the election to sell was made. In November 2021, both the Company's repurchase right and this put right were amended so that they could not be exercised for at least 181 days following the date the participant's award vests and a "Sell Fund Purchase Program" was implemented whereby, if specifically provided for in an award agreement, participants have the ability to tender shares for repurchase by the Company. The put right and the "Sell Fund Purchase Program" will no longer apply upon consummation of this offering. Additionally, if Banpu proposed to effect the sale of shares of common stock representing more than 80% of the total issued and outstanding shares of Banpu, it may have required the participation in such sale of all of the vested shares of common stock owned by participants.

Corporate Transactions; Change in Control. In the event of (1) any reorganization, merger, consolidation, recapitalization, liquidation, reclassification, stock dividend, stock split, combination of shares, rights offering, extraordinary dividend or divestiture or other similar change in corporate structure or shares, (2) any purchase, acquisition, sale, disposition or write-down of a significant amount of assets or a significant business, (3) any change in accounting principles or practices, tax laws or other such laws or provisions affecting reported results, (4) any uninsured catastrophic losses or extraordinary non-recurring items as described in Accounting Standards Codification 225-20, (5) an IPO or (6) any other similar change, in each case with respect to the Company or any other entity whose performance is relevant to the vesting of the PRSUs, the Committee may amend or modify the vesting criteria of any outstanding PRSUs to equitably reflect such event, with the desired result that the criteria for evaluating such financial performance of the Company or such other entity will be substantially the same following such event as prior to such event.

In the event of a Change in Control (as defined in the 2021 Plan), the board of directors or any corporation or entity assuming the obligations of the Company could have provided that awards outstanding under the 2021 Plan be vested in full or in part on the date of such Change in Control or could have provided that such awards be assumed or that an equivalent award be substituted by the acquiring or succeeding corporation. The performance period of the PRSUs would end as of the date of such Change in Control.

Transferability. Generally, awards under the 2021 Plan may not be transferred by a participant except by will or the laws of descent and distribution. However, the 2021 Plan allowed participants to designate a beneficiary that would receive payment or settlement of an award under the 2021 Plan in the event of the participant's death.

Market Standoff. Unless the Committee otherwise provides the participant with prior written consent, the 2021 Plan places market stand-off restrictions on shares of common stock acquired in connection with the grant, vesting or settlement of the PRSUs and TRSUs. The participant may not, without the consent of the Company or the representatives of any underwriters (for the duration determined by the Company and the representatives of the underwriters, but not to exceed 180 days from the date of the final prospectus), (1) sell, pledge, offer to sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase or otherwise transfer or dispose of, any shares of common stock or any securities convertible into or exercisable or exchangeable for common stock, or (2) enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock.

Amendment and Termination. The Committee has the authority to amend or modify for any reason the terms of any outstanding awards under the 2021 Plan, including the authority to modify the number of shares or other terms and conditions of an award, accept the surrender of an outstanding award or, to the extent to previously exercised or vested, authorize the grant of new awards in substitution for surrendered awards. However, the terms of any such amendments must be permitted by the 2021 Plan and such amendment may not (1) cause the award to become taxable under Section 409A of the Code or (2) adversely affect any participant without such participant's consent.

Our board of directors generally may amend, suspend or terminate the 2021 Plan in whole or in part. However, no termination, suspension or amendment of the 2021 Plan may adversely affect any outstanding award without the consent of the affected participant. The 2021 Plan shall terminate pursuant to its terms on the earlier of (1) six months following an IPO (including this offering) and (2) January 1, 2024; however, the board of directors acted to terminate the 2021 Plan in connection with the adoption of the 2022 Plan. Termination of the 2021 Plan pursuant to its terms will not affect the rights of the Company and participants and the Company's and participants' rights will remain in full force and effect as to all outstanding unvested or vested awards, and shares of common stock issued in settlement of awards.

BKV Corporation 2022 Equity And Incentive Compensation Plan

In connection with this offering, our board of directors adopted, and our stockholders approved, the 2022 Plan. The material terms of the 2022 Plan are as follows:

Purpose. The purpose of the 2022 Plan is to permit the grant of awards to our directors, officers and other employees and certain consultants, and to provide to such persons incentives and rewards for service and/or performance.

Administration; Effectiveness. The 2022 Plan will generally be administered by the Compensation Committee or any other committee of the board of directors designated by the board of directors to administer the 2022 Plan (for purposes of this section, the "Committee"). The Committee has the authority to determine eligible participants in the 2022 Plan, and to interpret and make determinations under the 2022 Plan. Any interpretation or determination by the Committee under the 2022 Plan will be final and conclusive. The Committee may delegate its administrative duties or powers to one or more of our officers. However, the board of directors shall have the same powers and authorities as the Committee with respect to grants of awards to non-employee directors and may, in its discretion, act in lieu of the Committee with respect to such awards.

Shares Available for Awards under the 2022 Plan. Subject to adjustment as described in the 2022 Plan, the number of shares of our common stock available for awards under the 2022 Plan is, in the aggregate, 10,000,000 shares of our common stock (which we refer to as the "Available Shares"), with such shares subject to adjustment to reflect any extraordinary cash dividend, stock dividend, split or combination of our common stock. The Available Shares may be shares of original issuance, treasury shares or a combination of the foregoing.

The 2022 Plan also contains limits on the maximum value at grant for awards to non-employee directors in any calendar year of $750,000.

Share Counting. The aggregate number of shares of our common stock available for award under the 2022 Plan will be reduced by one share of our common stock for every one share of our common stock subject to an award granted under the 2022 Plan.

Shares of our common stock subject to an award that is cancelled or forfeited, expires, is settled for cash or is unearned (in whole or in part) will be added back to the aggregate number of shares of our common stock available under the 2022 Plan, however, the following shares of our common stock will not be added back: (i) shares of our common stock withheld by us in payment of the exercise price of a stock option; (ii) shares of our common stock tendered or otherwise used in payment of the exercise price of a stock option; (iii) shares of our common stock withheld by us or tendered or otherwise used to satisfy a tax withholding obligation; (iv) shares of our common stock subject to share-settled appreciation rights that are not actually issued in connection with the settlement of such appreciation right; and (v) shares of our common stock reacquired by the Company on the open market or otherwise using cash proceeds from the exercise of stock options. In addition, if under the 2022 Plan a participant has elected to give up the right to receive cash compensation in exchange for shares of our common stock based on fair market value, such shares of our common stock will not count against the aggregate number of shares of our common stock available under the 2022 Plan.

Shares of our common stock issued or transferred pursuant to awards granted under the 2022 Plan in substitution for or in conversion of, or in connection with the assumption of, awards held by awardees of an entity engaging in a corporate acquisition or merger with us or any of our subsidiaries (which we refer to as "Substitute Awards") will not count against, nor otherwise be taken into account in respect of, the share limits under the 2022 Plan unless otherwise provided in the 2022 Plan. Additionally, shares of common stock available under certain plans that we or our subsidiaries may assume in connection with corporation transactions from another entity may be available for certain awards under the 2022 Plan, but will not count against, nor otherwise be taken into account in respect of, the share limits under the 2022 Plan.

Types of Awards Under the 2022 Plan. Pursuant to the 2022 Plan, we may grant stock options, appreciation rights, restricted stock, RSUs, performance shares, performance units, cash incentive awards, and certain other awards based on or related to shares of our common stock.

Each grant of an award under the 2022 Plan will be evidenced by an award agreement or agreements, which will contain such terms and provisions as the Committee may determine, consistent with the 2022 Plan. Those terms and provisions include the number of our shares of our common stock subject to each award, earning or vesting terms and any other terms consistent with the 2022 Plan. A brief description of the types of awards which may be granted under the 2022 Plan is set forth below.

Stock Options. Stock options granted under the 2022 Plan are non-qualified stock options and must have an exercise price per share that is not less than the fair market value of a share of our common stock on the date of grant. The term of a stock option may not extend more than 10 years after the date of grant. Each grant will specify the form of consideration to be paid in satisfaction of the exercise price.

Appreciation Rights. The 2022 Plan provides for the grant of appreciation rights. An appreciation right is a right to receive from us an amount equal to 100%, or such lesser percentage as the Committee may determine, of the spread between the base price and the value of shares of our common stock on the date of exercise. An appreciation right may be paid in cash, shares of our common stock or any combination thereof. Except with respect to Substitute Awards, the base price of an appreciation right may not be less than the fair market value of a share of common stock on the date of grant. The term of an appreciation right may not extend more than 10 years from the date of grant.

Restricted Stock. Restricted stock constitutes an immediate transfer of the ownership of shares of our common stock to the participant in consideration of the performance of services, entitling such participant to dividend, voting and other ownership rights, subject to the substantial risk of forfeiture and restrictions on transfer determined by the Committee for a period of time determined by the Committee or until certain management objectives specified by the Committee are achieved. Each such grant or sale of restricted stock may be made without additional consideration or in consideration of a payment by the participant that is less than the fair market value per share of our common stock on the date of grant. Any grant of restricted stock may specify the treatment of dividends or distributions paid on restricted stock that remains subject to a substantial risk of forfeiture. Any such dividends or other distributions on restricted stock shall be deferred until, and paid contingent upon, the vesting of such restricted stock.

Restricted Stock Units. RSUs awarded under the 2022 Plan constitute an agreement by us to deliver shares of our common stock, cash, or a combination thereof, to the participant in the future in consideration of the performance of services, but subject to the fulfillment of such conditions (which may include the achievement of management objectives) during the restriction period as the Committee may specify. Each grant or sale of RSUs may be made without additional consideration or in consideration of a payment by the participant that is less than the fair market value of shares of our common stock on the date of grant. During the applicable restriction period, the participant will have no ownership, transfer or voting rights in the shares of our common stock underlying the RSUs. Rights to dividend equivalents may be extended to and made part of any RSU award at the discretion of and on the terms determined by the Committee, provided that any dividend equivalents or other distributions on the shares of our common stock underlying the RSUs shall be deferred until and paid contingent upon the vesting of such RSUs. Each grant of RSUs will specify that the amount payable with respect to such RSUs will be paid in cash, shares of our common stock, or a combination of the two.

Cash Incentive Awards, Performance Shares, and Performance Units. Performance shares, performance units and cash incentive awards may also be granted to participants under the 2022 Plan. A performance share is a bookkeeping entry that records the equivalent of one share of our common stock, and a performance unit is a bookkeeping entry that records a unit equivalent to $1.00 or such other value as determined by the Committee. Each grant will specify the number or amount of performance shares or performance units, or the amount payable with respect to cash incentive awards, being awarded, which number or amount may be subject to adjustment to reflect changes in compensation or other factors.

These awards, when granted under the 2022 Plan, become payable to participants upon the achievement of specified management objectives and upon such terms and conditions as the Committee determines at the time of grant. Each grant will specify the management objectives regarding the earning of the award. Each grant will specify the time and manner of payment of cash incentive awards, performance shares or performance units that have been earned, and any grant may further specify that any such amount may be paid or settled in cash, shares of our common stock, or any combination thereof. Any grant of performance shares or performance units may provide for the payment of dividend equivalents in cash or in additional shares of our common stock, provided that such dividend equivalents shall be subject to deferral and payment on a contingent basis based on the earning and vesting of the performance shares or performance units, as applicable, with respect to which such dividend equivalents are paid.

Other Awards. The Committee may authorize the grant of such other awards (which we refer to as “other awards”) that may be denominated or payable in, valued in whole or in part by reference to, or otherwise based on, or related to, shares of our common stock or factors that may influence the value of such shares of our common stock, including, without limitation, convertible or exchangeable debt securities, other rights convertible or exchangeable into shares of our common stock, purchase rights for shares of our common stock, awards with value and payment contingent upon our performance or performance of specified subsidiaries, affiliates or other business units or any other factors designated by the Committee, and awards valued by reference to the book value of the shares of our common stock or the value of securities of, or the performance of our subsidiaries, affiliates or other business units.

Adjustments; Corporate Transactions. The Committee will make or provide for such adjustments in the: (i) number and kind of shares of our common stock covered by outstanding stock options, appreciation rights, restricted stock, RSUs, performance shares, performance units and, if applicable, other awards; (ii) exercise price or base price provided in outstanding stock options and appreciation rights; (iii) cash incentive awards; and (iv) other award terms, as the Committee determines to be equitably required in order to prevent dilution or enlargement of the rights of participants that otherwise would result from (a) any extraordinary cash dividend, stock dividend, stock split, combination of shares, recapitalization or other change in our capital structure, (b) any merger, consolidation, spin-off, spin-out, split-off, split-up, reorganization, partial or complete liquidation or other distribution of assets, issuance of rights or warrants to purchase securities or (c) any other corporate transaction or event having an effect similar to any of the foregoing.

In the event of any such transaction or event, or in the event of a change in control (as defined in the 2022 Plan), the Committee may provide in substitution for any or all outstanding awards under the 2022 Plan such alternative consideration (including cash), if any, as it may in good faith determine to be equitable under the circumstances and will require in connection therewith the surrender of all awards so replaced in a manner that complies with Section 409A of the Code. In addition, for each stock option or appreciation right with an exercise price greater than the consideration offered in connection with any such transaction or event or change in control, the Committee may in its discretion elect to cancel such stock option or appreciation right without any payment to the person holding such stock option or appreciation right. The Committee will make or provide for such adjustments to the number of shares available for issuance under the 2022 Plan and the share limits of the 2022 Plan as the Committee in its sole discretion may in good faith determine to be appropriate in connection with such transaction or event.

Transferability of Awards. Except as otherwise provided by the Committee, no stock option, appreciation right, restricted share, RSU, performance share, performance unit, cash incentive award, other award or dividend equivalents paid with respect to awards made under the 2022 Plan may be transferred by a participant except by will or the laws of descent and distribution.

Amendment and Termination of the 2022 Plan. Our board of directors generally may amend the 2022 Plan from time to time in whole or in part. However, if any amendment (i) would materially increase the benefits accruing to participants under the 2022 Plan, (ii) would materially increase the number of shares of our common stock which may be issued under the 2022 Plan, (iii) would materially modify the requirements for participation in the 2022 Plan, or (iv) must otherwise be approved by our stockholders in order to comply with applicable law or the rules of the NYSE, then such amendment will be subject to stockholder approval and will not be effective unless and until such approval has been obtained.

Our board of directors may, in its discretion, terminate the 2022 Plan at any time. Termination of the 2022 Plan will not affect the rights of participants or their successors under any awards outstanding and not exercised in full on the date of termination. No grant will be made under the 2022 Plan more than 10 years after the effective date of the 2022 Plan, but all grants made prior to such date shall continue in effect thereafter subject to the terms of the 2022 Plan.

IPO Equity Grants

The Compensation Committee approved the grant of RSU awards upon the consummation of this offering under the 2022 Plan, subject to final approval of our stockholders of the 2022 Plan, to our NEOs. Sixty percent (60%) of each RSU award is subject to performance-based vesting and will vest upon the achievement of pre-specified performance goals at the end of a three-year performance period and forty percent (40%) of each RSU award is subject to time-based vesting and will vest in three equal installments on each of the first three anniversaries of the grant date. The vesting of both the performance-based and time-based RSUs will be subject to the grantee’s continued employment through the applicable vesting date. We anticipate that the RSUs granted to our NEOs will have the following grant date fair values: Mr. Kalnin: $3,500,000, Mr. Jimenez: $1,600,000 and Mr. Jacobsen: $1,600,000. Following the vesting date, these RSU awards are expected to be settled in shares of our common stock.

BKV Corporation Employee Stock Purchase Plan

In connection with this offering, our board of directors adopted, and our stockholders approved, the ESPP. The ESPP is intended to qualify as an “employee stock purchase plan” under Section 423 of the Code. The material terms of the ESPP are as follows:

Purpose. The purpose of the ESPP is to provide employees of the Company and certain of its subsidiaries with an opportunity to acquire a proprietary interest in the Company through the purchase of shares of our common stock.

Administration. The ESPP will be administered by the Compensation Committee (for purposes of this section, the “Committee”). Subject to the terms of the ESPP, the Committee will have the complete discretion to establish the terms and conditions of offerings under the ESPP and the subsidiaries, if any, eligible to participate in such offerings, to interpret the ESPP and to make all decisions related to the operation of the ESPP. The board of directors has the same powers as the Committee and may act in lieu of the Committee with respect to the ESPP.

Shares Available for Issuance. Subject to adjustment as described in the ESPP, the number of shares of our common stock available for awards under the ESPP is 1,000,000 shares of our common stock.

Eligibility. All employees who have been employed by the Company or a designated subsidiary (whether currently existing or subsequently established) for at least six months prior to the beginning of an Offering and who work at least 20 hours per week and more than five months per calendar year are eligible to participate in the ESPP, resulting in approximately 329 employees (including six executive officers) as eligible participants. The Committee may permit employees who work less than 20 hours per week or less than five months per year to participate and may exclude certain categories of employees from participating in any offering to the extent permitted by Section 423 of the Code, including employees who have not completed a minimum period of service with the Company and/or highly compensated employees. An employee may be excluded from participation in the ESPP if his or her participation in the ESPP is prohibited by local law or if complying with local law would cause the ESPP or an offering to violate the requirements of Section 423 of the Code. Also, in accordance with Section 423 of the Code, no employee may be granted a right to purchase shares of the Company’s common stock under the ESPP if, immediately after such grant, such employee would own stock and/or hold outstanding options to purchase stock possessing 5% or more of the total combined voting power or value of all classes of stock of the Company or any subsidiary (including in such calculation stock held directly or indirectly by or for the benefit of the employee and stock held by certain persons related to the employee) or if such option would permit his or her rights to purchase stock under all employee stock purchase plans of the Company and its subsidiaries to accrue at a rate that exceeds $25,000 of the fair market value of such stock (determined at the time the option is granted) for each calendar year in which such option is outstanding at any time.

Participation. The ESPP will permit an eligible employee to purchase shares of the Company's common stock through payroll deductions, which may not exceed 10% of the employee's eligible compensation (or such lesser or greater limit as may be determined by the Committee for a particular offering). Employees will be able to withdraw all, but not less than all, of their accumulated payroll deductions prior to the end of an offering in accordance with the terms of the offering. Participation in the ESPP will end automatically upon termination of employment. In the event of withdrawal or termination of participation in the ESPP, a participant's accumulated payroll contributions will be refunded without interest.

Certain limitations on the number of shares of our common stock that a participant may purchase apply. For example, if an offering is over-subscribed whereby, when added together, the total number of shares of our common stock purchased by all participants in a given offering would exceed the total number of shares of our common stock remaining available under the ESPP, the Committee shall allocate such shares remaining available under the ESPP in as uniform a manner as practicable and as the Committee determines to be equitable.

Offerings; Purchase Price. The ESPP will be implemented through a series of offerings of up to a period of 27 months, which will consist of one offering period. During the offering period, payroll contributions will accumulate without interest and, on the last trading day of the offering period, accumulated payroll deductions will be used to purchase shares of our common stock.

The purchase price for each offering will be established by the Committee and may not be less than 85% of the fair market value of a share of our common stock on either the first trading day of an offering or on the purchase date, whichever is lower.

Adjustments. In the event that there occurs a change in our capital structure through such actions as an extraordinary cash or a stock dividend, a stock split, combination of shares or recapitalization, or a merger, consolidation, spin-off, split-off, spin-out, split-up, reorganization, partial or complete liquidation or other distribution of assets, issuance of rights or warrants to purchase securities, or any other corporate transaction or event having a similar effect, then in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the ESPP, the Committee will adjust (1) the number of shares reserved under the ESPP, (2) the number of shares by which the share reserve may increase automatically each year, (3) the purchase price of outstanding options and (4) the number of shares that are subject to purchase limits under an ongoing offering.

Dissolution or Liquidation. In the event of a proposed dissolution or liquidation of the Company, any offering then in progress will be shortened by setting a new purchase date before the proposed dissolution or liquidation and the offering will end immediately prior to the proposed dissolution or liquidation.

Change in Control. Unless otherwise determined by the Committee, in the event of a change in control (as defined in the ESPP) each outstanding option under the ESPP will be assumed or an equivalent option will be substituted by the successor corporation (or a parent or subsidiary of such successor corporation) and if the successor corporation refused to assume or substitute the options, then, unless otherwise provided by the Committee, the offering with respect to which the option relates will be shortened by setting a new purchase date, that will occur before the date of the change in control, on which the offering will end.

ESPP Amendment or Termination. The board of directors has the authority to amend or terminate our ESPP at any time. If any offering is terminated before its scheduled expiration, all amounts that have not been used to purchase shares of our common stock will be returned to participants (without interest, except as otherwise required by applicable law) as soon as administratively practicable. Unless earlier terminated by the board of directors, the ESPP shall have a term of 10 years.

Director Compensation

Name(1)	2022 Fees earned or paid in cash ($)(2)	Total($)
Chanin Vongkusolkit	—	—
Somruedee Chaimongkol	—	—
Joseph R. Davis	64,855	64,855
Akaraphong Dayananda	—	—
Carla S. Mashinski	24,684	24,684
Thiti Mekavichai	—	—
Charles C. Miller III	66,513	66,513
Sunit S. Patel	24,684	24,684
Anon Sirisaengtaksin	—	—
Sinon Vongkusolkit	—	—

(1) Mr. S. Vongkusolkit was elected to our board of directors effective July 19, 2022, and Ms. Mashinski and Mr.Patel were elected to our board effective September 1, 2022.

(2) From January 1, 2022 through August 31, 2022, Messrs. Davis and Miller each received a base cash retainer, at an annualized rate of $50,000, and additional cash retainers, at an annualized rate of $7,500, for service on the Compensation Committee (for Mr. Davis) and service on the Audit & Risks Committee (for Mr. Miller). Beginning on September 1, 2022, Messrs. Davis, Miller and Patel and Ms. Mashinski received cash retainers pursuant to the Non-Employee Director Compensation Program, described below, with the quarterly fees payable thereunder on September 30, 2022 prorated for the one-month period prior to such payment date that the Non-Employee Director Compensation Program had been effective. For Messrs. Davis and Miller, the cash retainers paid pursuant to the Non-Employee Director Compensation Program included fees earned for their services on the Compensation Committee (for Mr. Davis) and the Audit & Risks Committee (for Mr. Miller).

Through September 1, 2022, the non-executive members of our board of directors, other than Messrs. Davis and Miller, did not receive any compensation from the Company. Any compensation paid through such time by Banpu to our non-executive directors, including Messrs. C. Vongkusolkit, Dayananda, Mekavichai and Sirisaengtaksin and Ms. Chaimongkol, is not reflected as such compensation was not paid by us or our subsidiaries and related to such individual's services to Banpu.

Our board of directors adopted the BKV Corporation Non-Employee Director Compensation Program (the "Non-Employee Director Compensation Program") which provides that, beginning on September 1, 2022, our non-employee directors have been compensated as follows:

- Each non-employee director, other than a non-employee director who serves as chairman of the board, will be entitled to receive an annual cash retainer of $75,000, and any non-employee director serving as the chairman of the board will be entitled to receive an annual cash retainer of $137,500, each of which will be paid in quarterly installments, based on calendar quarters, in arrears on a prorated basis;
- Members of our Audit & Risks Committee (other than the chairperson thereof) will be entitled to receive an additional cash retainer of $10,000, and the chairperson of the Audit & Risks Committee will be entitled to receive an additional cash retainer of $20,000, each paid in quarterly installments, based on calendar quarters, in arrears on a prorated basis;
- Members of our Compensation Committee and Governance Committee (other than the chairpersons thereof) will be entitled to receive an additional cash retainer of $5,000, and the chairperson of the Compensation Committee and chairperson of the Governance Committee will be entitled to receive an additional cash retainer of $15,000, each paid in quarterly installments, based on calendar quarters, in arrears on a prorated basis;

- Each non-employee director who is re-elected to serve, or will continue serving as a non-employee director immediately following any annual meeting of the Company's stockholders, will receive an annual grant of RSUs on the date of the Company's annual shareholder meeting with a grant date value of $140,000, if such non-employee director will not serve as the chairman of the board, or $202,500 if such non-employee director will serve as the chairman of the board, which will vest on the day prior to the first annual meeting of the Company's stockholders following the date the RSUs are granted, subject to the non-employee director's continued service; and
- Each non-employee director will be reimbursed for reasonable out-of-pocket expenses incurred in attending meetings of the board or any of its committees.

Because the Non-Employee Director Compensation Program was adopted mid-term, compensation payable thereunder was pro-rated based on the non-employee director's service over the period beginning on the day the Non-Employee Director Compensation Program became effective through the day prior to the estimated date of the next annual meeting of the Company's stockholders. To the extent the 2022 Plan has not become effective prior to such meeting, cash will be paid in lieu of the RSU awards. Messrs. C. Vongkusolkit, Dayananda, Mekavichai, Sirisaengtaksin and S. Vongkusolkit and Ms. Chaimongkol have waived their participation in the Non-Employee Director Compensation Plan, and therefore will not receive any compensation payable thereunder.

PRINCIPAL STOCKHOLDERS

The following table sets forth certain information regarding the beneficial ownership of our common stock immediately following the completion of this offering by (i) each NEO and director of the Company, (ii) all executive officers and directors of the Company as a group, and (iii) each person known to the Company to own beneficially more than 5% of any class of our voting securities. Except as otherwise indicated, (a) the persons or entities identified in the table have sole voting and investment power with respect to all shares shown as beneficially owned by them and (b) the current directors and executive officers have not pledged any of such shares as security. All information with respect to beneficial ownership has been furnished by the respective 5% or more stockholders, directors or executive officers, as the case may be.

The following information has been presented in accordance with the SEC's rules and is not necessarily indicative of beneficial ownership for any other purpose. Under the SEC's rules, beneficial ownership of a class of capital stock as of any date includes any shares of that class as to which a person, directly or indirectly, has or shares voting power or investment power as of that date and also any shares as to which a person has the right to acquire sole or shared voting or investment power as of or within 60 days after that date through the exercise of any stock option, warrant or other right (including any conversion or redemption right).

We have based our calculation of the percentage of beneficial ownership prior to this offering on 117,534,453 shares of our common stock outstanding. We have based our calculation of the percentage of beneficial ownership after this offering on shares of our common stock outstanding immediately following the completion of this offering, assuming that the underwriters do not exercise their option to purchase additional shares.

Unless otherwise indicated, the address of each beneficial owner listed in the table below is c/o BKV Corporation, 1200 17th Street, Suite 2100, Denver, Colorado 80202.

	Beneficial Ownership Before the Offering			Beneficial Ownership After the Offering		
	Common Stock		Total Voting Power Before the Offering	Common Stock		Total Voting Power After the Offering
Name of Beneficial Owner	Shares	%	%	Shares	%	%
Named Executive Officers and Directors:						
Christopher P. Kalnin	3,591,151(1)	3.1%	3.1%			
John T. Jimenez	47,377(2)	*	*			
Eric S. Jacobsen	49,368(3)	*	*			
Barry S. Turcotte	—	—%	—%			
Somruedee Chaimongkol	—	—%	—%			
Joseph R. Davis	46,000	*	*			
Akaraphong Dayananda	—	—%	—%			
Carla S. Mashinski	—	—%	—%			
Thiti Mekavichai	37,000	*	*			
Charles C. Miller III	175,000	*	*			
Sunit S. Patel	—	—%	—%			
Anon Sirisaengtaksin	—	—%	—%			
Chanin Vongkusolkit	—	—%	—%			
Sinon Vongkusolkit	—	—%	—%			
All executive officers and directors as a group (17 persons)	4,301,783	3.7%	3.7%			
5% Stockholders:						
Banpu North America Corporation(4)	112,755,229	95.9%	95.9%			

* Less than 1%.

(1) Includes 1,751,509 shares of our common stock held by Mr. Kalnin's spouse. Does not include 1,825,040 shares of our common stock underlying outstanding PRSUs (at maximum payout) that are subject to vesting to the extent that performance measures are achieved. In addition, Mr. Kalnin will receive 146,657 shares of our common stock underlying outstanding TRSUs that will vest upon consummation of this offering.

(2) Includes 23,175 shares of our common stock underlying outstanding TRSUs that will vest within 60 days of the date of this prospectus. Does not include 865,200 shares of our common stock underlying outstanding PRSUs (at maximum payout) that are subject to vesting to the extent that performance measures are achieved. In addition, Mr. Jimenez will receive 34,764 shares of our common stock underlying outstanding TRSUs that will vest upon consummation of this offering.

(3) Does not include 1,036,000 shares of our common stock underlying outstanding PRSUs (at maximum payout) that are subject to vesting to the extent that performance measures are achieved. In addition, Mr. Jacobsen will receive 83,250 shares of our common stock underlying outstanding TRSUs that will vest upon consummation of this offering.

(4) Approximately 95.9% of our outstanding shares of common stock are currently owned by BNAC, a Delaware corporation wholly owned by BOG Co., Ltd., a wholly owned subsidiary of Banpu, a public company listed on the Stock Exchange of Thailand and the ultimate parent company of BKV Corporation, BNAC, Banpu Power and BPPUS. The principal address of Banpu is 27th Floor, Thanapoom Tower, 1550 New Petchburi Road, Makkasan, Ratchathewi, Bangkok, Thailand.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

We describe below transactions and series of similar transactions, during our last three fiscal years or currently proposed, to which we were a party or will be a party, in which:

- the amounts involved exceeded or will exceed $120,000; and
- any of our directors, director nominees, executive officers or beneficial holders of more than 5% of any class of our voting securities, or any immediate family member of any such person, had, or will have, a direct or indirect material interest.

Other than as described below, there have not been, nor are there any currently proposed, transactions or series of similar transactions meeting these criteria to which we have been or will be a party other than compensation arrangements, which are described where required under "*Executive Compensation.*"

Stockholders' Agreement

We are party to a stockholders' agreement, dated as of May 1, 2020, with certain of our stockholders, including BNAC and Chris Kalnin. Our existing stockholders' agreement will be terminated prior to the completion of this offering.

Additionally, in connection with the closing of this offering, we will enter into our Stockholders' Agreement with BNAC. Pursuant to our Stockholders' Agreement, for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that (i) from the completion of this offering until the first anniversary of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. Under our Stockholders' Agreement, we will agree to use our best efforts to cause the election of the individuals nominated by BNAC to our board of directors, including nominating such individuals to be elected as a director, recommending their election and soliciting proxies or consents in favor of their election. Our Stockholders' Agreement also provides that we and BNAC shall, to the extent permitted by law, take actions to cause our Chief Executive Officer to be included in our board of directors.

In addition, for so long as BNAC and its affiliates beneficially own shares of our voting stock representing at least 25% of our total voting power, BNAC will have the right to designate the chairman of our board of directors from among its designees. Our Stockholders' Agreement will also provide BNAC with certain information rights for so long as it continues to own shares of our voting stock representing at least 25% of our voting power. Further, we may not amend our charter or our bylaws in a manner inconsistent with the rights granted to BNAC pursuant to our Stockholders' Agreement without BNAC's consent.

Our Stockholders' Agreement will terminate on the earlier to occur of (i) such time as BNAC is no longer entitled to designate a director pursuant to our Stockholders' Agreement (except that the registration rights discussed below will survive and continue until BNAC and its affiliates no longer hold any shares of our common stock constituting registrable securities (as defined in our Stockholders' Agreement)) and (ii) the delivery of written notice by BNAC to us requesting termination of our Stockholders' Agreement.

BKV-BPP Power Joint Venture

BKV-BPP Power is jointly controlled by us and BPPUS through a board of directors (the "BKV-BPP board") consisting of eight members, four of whom are appointed by us and four of whom are appointed by BPPUS. We account for BKV-BPP Power using the equity method of accounting.

In November 2021, BKV-BPP Power acquired Temple I for an aggregate purchase price of $430.0 million. BKV-BPP Power was formed in July 2021 for the purpose of purchasing and operating Temple I and is a joint venture owned 50% by us and 50% by BPPUS, a wholly owned subsidiary of Banpu Power.

In connection with the purchase of Temple I, we made a capital contribution to BKV-BPP Power in the amount of $87.0 million and BPPUS made a capital contribution to BKV-BPP Power in the amount of $87.0 million.

BKV-BPP Loan Agreements

On October 14, 2021, BKV-BPP Power entered into a Loan Agreement (the “$141 Million Banpu Loan Agreement”) with BNAC, which allowed for a single drawdown in the amount of $141.0 million. On November 1, 2021, BKV-BPP Power borrowed $141.0 million for the purpose of acquiring Temple I and working capital.

On October 15, 2021, BKV-BPP Power entered into a Loan Agreement (the “141 Million BPPUS Loan Agreement” and, together with the $141 Million Banpu Loan Agreement, the “BKV-BPP Loan Agreements”) with BPPUS, which allowed for a single drawdown in the amount of $141.0 million. On November 21, 2021, BKV-BPP Power borrowed $141.0 million for the purpose of acquiring Temple I and working capital.

BKV-BPP Power’s payment obligations under the BKV-BPP Loan Agreements are senior unsecured indebtedness. The BKV-BPP Loan Agreements bear interest at six-month LIBOR plus 5.25% per annum. Upon the cessation of LIBOR as a reference rate, which is expected June 30, 2023, the reference rate for the interest rate under the BKV-BPP Loan Agreements will be such other rate as agreed by the parties. Interest on the loans is payable on a semi-annual basis, and the loans will mature on November 1, 2023. BKV-BPP is permitted to prepay the loans at any time, with no prepayment premium. The BKV-BPP Loan Agreements include covenants that, among other things, prohibit BKV-BPP from merging, incurring liens or incurring any additional indebtedness or guarantees. The BKV-BPP Loan Agreements include financial covenants that require BKV-BPP to maintain a minimum net worth (as defined in the BKV-BPP Loan Agreements, but generally meaning total assets minus total liabilities). In the $141 Million Banpu Loan Agreement, the minimum net worth requirement is $120.0 million and in the $141 Million BPPUS Loan Agreement, the minimum net worth requirement is $40.0 million. Under the BKV-BPP Loan Agreements, BNAC and BPPUS have no recourse to us with respect to any amounts owed to them thereunder and we are not liable in any manner (and are not required to provide security) for any obligations owed to them thereunder.

BKV-BPP Power Limited Liability Company Agreement

We and BPPUS are each a party to the BKV-BPP Power LLC Agreement governing the BKV-BPP Power Joint Venture, which, among other things, provides that a general manager appointed by the BKV-BPP board will have the power to manage and administer the business and affairs of BKV-BPP Power, subject to specified matters reserved for approval by the BKV-BPP board. The appointment and removal of the general manager must be approved by both the BKV-BPP board and BPPUS. Transfer or encumbrance of a party’s interest in BKV-BPP Power is permitted without prior approval of the other party or the BKV-BPP board. However, no transfer will be permitted if the transfer: (A) would subject BKV-BPP Power to U.S. federal securities law reporting requirements, (B) would cause BKV-BPP Power to lose its status as a U.S. partnership for federal income tax purposes or will cause BKV-BPP Power to be classified as a “publicly traded partnership,” (C) would violate, give rise to a default under or cause any payment to become due under any credit agreement, guaranty, or similar credit document or any other material contract to which BKV-BPP Power or any affiliate is bound, or (D) occurs prior to the repayment by BKV-BPP Power of all loans and other amounts outstanding under the term loans.

In the event that either party admits in writing that it is unable to perform its obligations (including any obligation to provide additional capital contributions) under the BKV-BPP Power LLC Agreement, the non-defaulting party will be entitled to (i) sell the assets of the joint venture and dissolve the joint venture on reasonable terms deemed acceptable to the BKV-BPP board, (ii) obtain specific performance of the non-defaulting party’s obligations, and/or (iii) exercise any other right or remedy provided in law or in equity.

The BKV-BPP board will determine the amount and timing of distributions of operating cash flow (which will be done no less frequently than once per quarter) and net capital proceeds (which will be distributed within three business days after becoming available for distribution). All distributions will be made on a pro-rata basis to us and BPPUS. As of December 31, 2022, no distributions have been made by

BKV-BPP Power. Additional cash capital contributions will be required to be made by us and by BPPUS on a pro-rata basis upon 30 days written notice either by us or by BPPUS; provided that the additional contributions must be expended on items included in the annual approved budget, items in response to an emergency in the event that BKV-BPP Power does not have sufficient cash reserves to address such emergency, or any other matter approved by the BKV-BPP board. Otherwise, neither us nor BPPUS will be required to provide additional capital contributions without consent.

Major decisions and significant activities of BKV-BPP Power are reserved for approval by at least a majority of the members of the BKV-BPP board, such as, among other things, any merger, consolidation, amalgamation, conversion of BKV-BPP or any of its subsidiaries, into another form or entity or other business combination of any nature, wind up, the dissolution, liquidation, commencement or any filing or petition for a voluntary bankruptcy, reorganization, debt arrangement involving BKV-BPP Power, any plan to or initial sale of BKV-BPP Power or other equity interests to the public, any amendments, restatements or revocations of its organizational documents, execution, amendment or termination of a material contract, and any amendment to or deviation from the dividend policy of the joint venture or any of its subsidiaries. Under the terms of the BKV-BPP Power LLC Agreement:

- we do not have the power to unilaterally cause BKV-BPP Power to make distributions;
- we may be required to make additional capital contributions to fund items approved in the annual budget or other matters approved by the board of BKV-BPP Power at the request of BPPUS, which would reduce the amount of cash otherwise available for dividend payments by us on our common stock or require us to incur additional indebtedness; and
- BKV-BPP Power may incur additional indebtedness in an amount greater than $1,500,000 if approved by the board of BKV-BPP Power, which debt payments would reduce the amount of cash that might otherwise be available for distributions to us.

In December 2021, we entered into an Administrative Service Agreement (as amended on December 1, 2022, the “Administrative Services Agreement”) with BKV-BPP Power. Under the Administrative Service Agreement, we provide certain operational, accounting, tax and other services as required by the Administrative Services Agreement and in return receive an annual fee of $2.65 million until December 1, 2023, with options to extend. In addition to the annual fee, we are entitled to receive reimbursement for all (i) reasonable, ordinary and necessary out-of-pocket expenses actually incurred in connection with travel, (ii) actual costs of audits, legal fees, tax return preparations and other third-party professional fees approved by BKV-BPP Power and (iii) reasonable, ordinary and necessary out-of-pocket expenses actually incurred by us in connection with the services provided by us under the Administrative Services Agreement. During the years ended December 31, 2022 and 2021, we recognized $2.7 million and $0.2 million, respectively, of revenues related to the services provided under the Administrative Services Agreement.

Loan Agreements

Intercompany Loan Agreements

On December 17, 2019, BKV O&G entered into the $10 Million Loan Agreement with BNAC, which allowed for a single drawdown in the amount of $10.0 million. On June 23, 2020, we entered into a novation agreement with BKV O&G and BNAC, which transferred all of BKV O&G’s rights and obligations under the $10 Million Loan Agreement to us. Also on June 23, 2020, we entered into the First Amendment to the Loan Agreement. On July 1, 2020, we borrowed $10.0 million thereunder for working capital purposes. During the year ended December 31, 2020, we paid $0.2 million in interest on the loan, and on December 31, 2020, we repaid $5.0 million of the outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.1 million in interest on the loan and repaid the remaining outstanding principal amount of the loan in full. The First Amendment to $10 Million Loan Agreement terminated on June 20, 2021.

On September 28, 2020, we borrowed $119.0 million under the $119 Million Loan Agreement with BNAC to partially fund the Devon Barnett Acquisition and for working capital. During the year ended December 31, 2020, we paid $1.5 million in interest on the loan, and on December 16, 2020, we repaid $100.0 million of the outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.2 million in interest on the loan, and on March 15, 2021, we repaid the remaining outstanding principal amount of the loan in full. The $119 Million Loan Agreement terminated concurrently with repayment of the remaining principal amount.

On November 8, 2021, we borrowed $50.0 million under the $50 Million Loan Agreement with BNAC. On January 11, 2022, we repaid $15.0 million of the outstanding principal amount of the loan. On June 1, 2022, we paid $1.3 million in interest on the loan and repaid the remaining $35.0 million of the outstanding principal amount of the loan in full. The $50 Million Loan Agreement terminated concurrently with repayment of the remaining principal amount.

For additional information, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Intercompany Loan Agreements.*"

Subordinated Intercompany Loan Agreements

On October 14, 2021, we borrowed $116.0 million under the $116 Million Loan Agreement with BNAC to redeem all of the outstanding preferred and common stock of the company owned by OCM BKV Holdings, LLC, an affiliate of Oaktree Capital Management L.P. Following such redemption, we do not have any issued and outstanding preferred stock. On June 15, 2022, we entered into the $116 Million A&R Loan Agreement, which amended and restated the $116 Million Loan Agreement to, among other things, subordinate the $116.0 million term loan owed to BNAC thereunder to the term loans we borrowed under the Term Loan Credit Agreement. On August 24, 2022, BNAC entered into a Subordination Agreement with Bangkok Bank Public Company Limited, New York Branch, which subordinated the $116.0 million term loan owed to BNAC to the revolving loans at any time outstanding under the Revolving Credit Agreement (the "August 2022 Subordination Agreement"). On September 16, 2022, we repaid the full $116.0 million balance of the loan.

On March 10, 2022, we borrowed $75.0 million under the $75 Million Loan Agreement with BNAC to fund the deposit for the Exxon Barnett Acquisition. On June 15, 2022, we entered into the $75 Million A&R Loan Agreement, which amended and restated the $75 Million Loan Agreement to, among other things, subordinate the $75.0 million term loan owed to BNAC thereunder to the term loans we borrowed under the Term Loan Credit Agreement. The August 2022 Subordination Agreement provides for the subordination of the $75.0 million term loan owed to BNAC thereunder to the revolving loans at any time outstanding under the Revolving Credit Agreement. We intend to use a portion of the net proceeds from this offering to repay in full the $75 Million A&R Loan Agreement.

For additional information, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Subordinated Intercompany Loan Agreements*."

Tax Sharing Agreement

Since our inception, BNAC has owned, directly and indirectly, in excess of 80% of the outstanding shares of our common stock, with the result that we have been included in BNAC's consolidated federal income tax group (as well as in certain consolidated, combined and unitary state and local income tax returns filed by BNAC). If and when BNAC's ownership of our common stock falls below 80%, we will cease to be part of BNAC's consolidated federal income tax group. We are party to a Tax Sharing Agreement, dated as of May 1, 2020 (the "Existing Tax Sharing Agreement"), with BNAC, providing for payment by us to BNAC of the amounts payable by us in respect of U.S. federal income taxes and certain state and local taxes, and for certain payments by BNAC to us. We made no payments to BNAC under the Existing Tax Sharing Agreement in 2020, 2021 and 2022.

At the completion of this offering, we anticipate BNAC will own less than 80% of the outstanding shares of our common stock and, as a result, we will generally be deconsolidated from BNAC for federal and, in most cases, state, income tax purposes for periods beginning after completion of the offering. In anticipation of this offering, we will enter into an Amended and Restated Tax Sharing Agreement with BNAC, which sets forth the principles and responsibilities (i) governing the allocation of consolidated U.S.

federal income tax liabilities and consolidated, combined and unitary state and local income tax liabilities between us and BNAC during the periods in which we have been and are included in any consolidated or combined income tax return filed by BNAC, (ii) specifying the allocation of tax attributes and tax liabilities in connection with deconsolidation and (iii) setting forth agreements with respect to certain other tax matters.

The Amended and Restated Tax Sharing Agreement contains provisions that we believe are customary for tax sharing agreements between members of a consolidated group. In particular, we make payments to BNAC in respect of our allocable share of the U.S. federal income consolidated tax liability and state and local combined tax liability, in each case as determined on a separate return basis. In addition, we are compensated for the use of our net operating losses and other tax assets to the extent such assets reduce the U.S. federal income consolidated tax liability or state and local combined tax liability, as applicable, during the periods in which we have been and are included in any consolidated or combined income tax return filed by BNAC. The Amended and Restated Tax Sharing Agreement also includes customary indemnification clauses and survives until all obligations and liabilities of the parties arising under the agreement are satisfied.

Registration Rights

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets and with certain piggyback rights, as described below. Our Stockholders' Agreement will also provide that we will pay certain expenses of BNAC and its affiliates relating to such registrations and indemnify them against certain liabilities that may arise under the Securities Act.

Demand Rights/Shelf Registration Rights

Subject to certain limitations, following the date that is six months after the consummation of this offering, BNAC and its affiliates will have the right, by delivering written notice to us, to require us to register the number of their registrable securities requested under the Securities Act. In no event later than 45 days after receiving a valid demand request, we are required to file or confidentially submit, at our discretion, with the SEC a registration statement covering all of the registrable securities covered by such demand request, subject to the limitations discussed below. We will not be obligated to effect more than two such registered offerings in any twelve-month period.

Upon the delivery of written notice to us by BNAC and its affiliates from time to time after a shelf registration statement has been declared effective by the SEC, we will facilitate a takedown of registrable securities off of an effective shelf registration statement. We will not be required to effect (i) an underwritten shelf takedown unless the offering includes securities with a total offering price (including piggyback securities and before deducting underwriting discounts) reasonably expected to exceed, in the aggregate, $5.0 million and (ii) more than two offerings demanded pursuant to this paragraph or the preceding paragraph in any twelve-month period.

In addition, if we are eligible to file a shelf registration statement on Form S-3, BNAC and its affiliates can request that we register their registrable securities for resale on a shelf registration statement.

Piggyback Rights

BNAC and its affiliates will be entitled to request to participate in, or "piggyback" on, registrations of common stock for sale by us or underwritten shelf takedowns. This piggyback right does not apply to, among other things, a registration relating to our employee benefit plans, a registration on Form S-4 or Form S-8 (or any similar successor forms) or a registration where the registrable securities are not being sold for cash.

Conditions and Limitations

The rights outlined above will be subject to conditions and limitations, including the right of the underwriters to limit the number of shares of our common stock to be included in a registration statement and our right to postpone or suspend a registration statement under specified circumstances.

Indemnification Agreements with our Directors and Officers

We intend to enter into indemnification agreements, to be effective upon the completion of this offering, with each of our directors and officers. The indemnification agreements and our governing documents will require us to indemnify our directors and officers to the fullest extent permitted by Delaware law. Subject to certain limitations, the indemnification agreements and our governing documents will also require us to advance expenses incurred by our directors and officers. For more information regarding these agreements, see "*Description of Capital Stock — Limitations of Liability and Indemnification*."

Employee Relationship with Chief Legal Officer

Tara Blevins, the sister of Lindsay B. Larrick, our Chief Legal Officer, is employed by the Company in a non-executive officer position and received total compensation of approximately $166,000, $161,000 and $266,000 in 2020, 2021 and 2022, respectively. Her compensation was established by the Company in accordance with its compensation practices applicable to employees with comparable qualifications and responsibilities and holding similar positions.

Independent Contractor Relationship with Chief Executive Officer and Director

Rebecca Kalnin, the spouse of Christopher P. Kalnin, our Chief Executive Officer and a director of the Company, is engaged as an independent contractor, through Wood Group PSN, Inc., a third-party consulting firm, as a Human Resources Advisor to the Company. The Company made payments of approximately $148,000 in 2022 to such firm for her services, and, in turn, such firm paid her less than $120,000 in 2022.

Policies and Procedures Regarding Related Party Transactions

Upon completion of this offering, we expect that our board of directors will adopt a new written Code of Business Conduct and Ethics that complies with all applicable requirements of the SEC and NYSE and that contains conflict of interest policies governing transactions involving any director, executive officer or beneficial owner of more than 5% of any class of our voting securities that could be deemed to present a conflict of interest.

Upon completion of this offering, we expect that our board of directors will adopt a written related party transactions policy, pursuant to which our Audit & Risks Committee will be responsible for reviewing and either approving, ratifying or disapproving such transactions with our directors, officers or beneficial owners of more than 5% of any class of our voting securities, or any immediate family member of any of the foregoing persons. In considering a related party transaction, our Audit & Risks Committee will take into account relevant facts and circumstances relating to whether the transaction is in the best interests of the Company, including the following:

- the materiality of the transaction to the related party and the Company;
- the business purpose for and reasonableness of the transaction; and
- whether the transaction is comparable to a transaction that could be available with an unrelated party or is on terms that the Company offers generally to persons who are not related parties.

DESCRIPTION OF CAPITAL STOCK

General

The following description summarizes certain important terms of our capital stock and of our governing documents, as each will be in effect upon the completion of this offering. For a complete description of the matters set forth in this section titled "*Description of Capital Stock*," you should refer to our governing documents, which are included as exhibits to the registration statement of which this prospectus forms a part, and to the applicable provisions of Delaware law.

Upon completion of this offering, our authorized capital stock will consist of 500,000,000 shares of common stock, $0.01 par value per share, of which shares (or shares if the underwriters exercise in full their option to purchase additional shares) will be issued and outstanding and 80,000,000 shares of preferred stock, $0.01 par value per share, of which no shares will be issued and outstanding. In addition, 10,000,000 shares of our common stock will be reserved for issuance pursuant to our 2022 Plan, including shares of common stock that may be issued upon vesting of equity awards that we expect to be granted in connection with this offering, and 1,000,000 shares of common stock will be available for purchase by employees pursuant to our ESPP. See "*Executive Compensation — BKV Corporation 2022 Equity and Incentive Compensation Plan" and "Executive Compensation — BKV Corporation Employee Stock Purchase Plan.*"

BNAC owns approximately 95.9% of our common stock.

Common Stock

Holders of shares of our common stock are entitled to one vote for each share held of record on all matters on which stockholders are entitled to vote generally, including the election or removal of directors elected by our stockholders generally. Holders of our common stock do not have cumulative voting rights in the election of directors. Subject to certain nomination rights of BNAC under our Stockholders' Agreement, holders of our common stock will be entitled to elect all directors to our board of directors. See "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*."

Holders of shares of our common stock are entitled to receive dividends when, as and if declared by our board of directors out of funds legally available therefor, subject to any statutory or contractual restrictions on the payment of dividends and to any restrictions on the payment of dividends imposed by the terms of any outstanding preferred stock. See "*Dividend Policy*."

Upon our liquidation, dissolution or winding up and after payment in full of all amounts required to be paid to creditors and to the holders of preferred stock having liquidation preferences, if any, the holders of shares of our common stock will be entitled to receive pro rata our remaining assets available for distribution.

All shares of our common stock that will be outstanding at the time of the completion of the offering will be fully paid and non-assessable. Our common stock will not be subject to further calls or assessments by us. Holders of shares of our common stock do not have preemptive, subscription, redemption or conversion rights. There will be no redemption or sinking fund provisions applicable to our common stock. The rights powers, preferences and privileges of our common stock will be subject to those of the holders of any shares of our preferred stock or any other series or class of stock we may authorize and issue in the future.

Preferred Stock

No shares of preferred stock will be issued or outstanding immediately after the offering contemplated by this prospectus. Our certificate of incorporation authorizes our board of directors to establish one or more series of preferred stock (including convertible preferred stock). Unless required by law or any stock exchange, the authorized shares of preferred stock will be available for issuance without further action by the holders of our common stock. Our board of directors is able to determine, with respect to any series of preferred stock, the powers (including voting powers), preferences and relative, participating, optional or other special rights, and the qualifications, limitations or restrictions thereof, including, without limitation:

- the designation of the series;
- the number of shares of the series, which our board of directors may, except where otherwise provided in the preferred stock designation, increase (but not above the total number of authorized shares of the class) or decrease (but not below the number of shares then outstanding);
- whether dividends, if any, will be cumulative or non-cumulative and the dividend rate of the series;
- the dates at which dividends, if any, will be payable;
- the redemption or repurchase rights and price or prices, if any, for shares of the series;
- the terms and amounts of any sinking fund provided for the purchase or redemption of shares of the series;
- the amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs;
- whether the shares of the series will be convertible into shares of any other class or series, or any other security, of us or any other entity, and, if so, the specification of the other class or series or other security, the conversion price or prices or rate or rates, any rate adjustments, the date or dates as of which the shares will be convertible and all other terms and conditions upon which the conversion may be made;
- restrictions on the issuance of shares of the same series or of any other class or series; and
- the voting rights, if any, of the holders of the series.

Dividends

The DGCL permits a corporation to declare and pay dividends on shares of its capital stock out of “surplus” or, if there is no “surplus,” out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. “Surplus” is defined as the excess of the net assets of the corporation over the amount determined to be the capital of the corporation by its board of directors. The capital of the corporation is typically calculated to be (and cannot be less than) the aggregate par value of all issued shares of capital stock. Net assets equals the fair value of the total assets minus total liabilities. The DGCL also provides that dividends may not be paid out of net profits if, after the payment of the dividend, remaining capital would be less than the capital represented by the outstanding stock of all classes having a preference upon the distribution of assets. Declaration and payment of any dividend will be subject to the discretion of our board of directors. See “*Dividend Policy*.”

Annual Stockholder Meetings

Our bylaws provide that annual stockholder meetings will be held at a date, time and place, if any, as determined by our board of directors or a duly authorized committee thereof. To the extent permitted under applicable law, we may conduct meetings by remote communications, including by webcast.

Anti-Takeover Provisions

Our governing documents and the DGCL contain provisions, which are summarized in the following paragraphs, that are intended to enhance the likelihood of continuity and stability in the composition of our board of directors. These provisions are intended to avoid costly takeover battles, reduce our vulnerability to a hostile or abusive change of control and enhance the ability of our board of directors to maximize stockholder value in connection with any unsolicited offer to acquire us. However, these provisions may have an anti-takeover effect and may delay, deter or prevent a merger or acquisition of the Company by means of a tender offer, a proxy contest or other takeover attempt that a stockholder might consider in its best interest, including those attempts that might result in a premium over the prevailing market price for the shares of common stock held by stockholders.

Authorized but Unissued Capital Stock

Delaware law does not require stockholder approval for any issuance of shares that are authorized and available for issuance. However, the listing requirements of the NYSE, which would apply so long as our common stock remains listed on the NYSE, require stockholder approval of certain issuances equal to or exceeding 20% of the then outstanding voting power of our capital stock or then outstanding number of shares of common stock. These additional shares may be used for a variety of corporate purposes, including future public offerings, to raise additional capital or to facilitate acquisitions.

Our board of directors may generally issue shares of one or more series of preferred stock on terms calculated to discourage, delay or prevent a change of control of the Company or the removal of our management. Moreover, our authorized but unissued shares of preferred stock will be available for future issuances in one or more series without stockholder approval and could be utilized for a variety of corporate purposes, including future offerings to raise additional capital, to facilitate acquisitions and employee benefit plans.

One of the effects of the existence of authorized and unissued and unreserved common stock or preferred stock may be to enable our board of directors to issue shares to persons friendly to current management, which issuance could render more difficult or discourage an attempt to obtain control of the Company by means of a merger, tender offer, proxy contest or otherwise, and thereby protect the continuity of our management and possibly deprive our stockholders of opportunities to sell their shares of common stock at prices higher than prevailing market prices.

Classified Board of Directors

Our certificate of incorporation provides that our board of directors will be divided into three classes of directors, with each class to be as equal in number as possible, and with the directors serving staggered three-year terms. As a result, approximately one-third of our board of directors will be elected each year. The classification of directors will have the effect of making it more difficult for stockholders to change the composition of our board of directors. Our certificate of incorporation provides that, subject to any rights of holders of preferred stock to elect additional directors under specified circumstances, the total number of directors will be determined from time to time by the affirmative vote of a majority of the total number of directors then in office.

Delaware Law

We will be subject to the provisions of Section 203 of the DGCL regulating corporate takeovers. Section 203 of the DGCL provides that, subject to exceptions specified therein, an “interested stockholder” of a Delaware corporation shall not engage in any “business combination,” including general mergers or consolidations or acquisitions of additional shares of the corporation, with the corporation for a three-year period following the time that such stockholder becomes an interested stockholder unless:

- prior to such time, the board of directors of the corporation approved either the business combination or the transaction that resulted in the stockholder becoming an interested stockholder;
- upon consummation of the transaction that resulted in the stockholder becoming an “interested stockholder,” the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced (excluding specified shares); or
- at or subsequent to such time, the business combination is approved by the board of directors of the corporation and authorized at an annual or special meeting of stockholders, and not by written consent, by the affirmative vote of at least 66⅔% of the outstanding voting stock not owned by the interested stockholder.

Under Section 203 of the DGCL, the restrictions described above also do not apply to specified business combinations proposed by an interested stockholder following the announcement or notification of one of specified transactions involving the corporation and a person who had not been an interested stockholder during the previous three years or who became an interested stockholder with the approval of a majority of the corporation’s directors, if such transaction is approved or not opposed by a majority of the directors who were directors prior to any person becoming an interested stockholder during the previous three years or were recommended for election or elected to succeed such directors by a majority of such directors.

Except as otherwise specified in Section 203 of the DGCL, an "interested stockholder" is defined to include:

- any person that is the owner of 15% or more of the outstanding voting stock of the corporation, or is an affiliate or associate of the corporation and was the owner of 15% or more of the outstanding voting stock of the corporation at any time within three years immediately prior to the date of determination; and
- the affiliates and associates of any such person.

Under some circumstances, Section 203 of the DGCL makes it more difficult for a person who is an interested stockholder to effect various business combinations with us for a three-year period following the time such stockholder became an interested stockholder.

A Delaware corporation may "opt out" of Section 203 of the DGCL with an express provision in its original certificate of incorporation or an express provision in its certificate of incorporation or bylaws resulting from amendments approved by the holders of at least a majority of the corporation's outstanding voting shares. We do not intend to "opt out" of the provisions of Section 203 of the DGCL. The statute could prohibit or delay mergers or other takeover or change in control attempts and, accordingly, may discourage attempts to acquire us.

Removal of Directors; Vacancies and Newly Created Directorships

Under the DGCL, unless otherwise provided in our certificate of incorporation, directors serving on a classified board may be removed by the stockholders only for cause. Our certificate of incorporation provides that directors may be removed only for cause and only by the affirmative vote of the holders of at least 60% in voting power of all the then-outstanding shares of our stock entitled to vote generally in the election of directors, voting together as a single class. In addition, our certificate of incorporation provides that, subject to the rights granted to the holders of one or more series of preferred stock then outstanding or the rights granted under our Stockholders' Agreement, any vacancies on our board of directors, and any newly created directorships, will be filled by a majority of the total number of directors then in office, even if less than a quorum, or by a sole remaining director, and not by the stockholders.

No Cumulative Voting

Under the DGCL, the right to vote cumulatively does not exist unless the certificate of incorporation specifically authorizes cumulative voting. Our certificate of incorporation does not authorize cumulative voting. Therefore, stockholders holding a majority in voting power of the shares of our stock entitled to vote generally in the election of directors will be able to elect all our directors, subject to certain nomination rights of BNAC under our Stockholders' Agreement. See "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*."

Special Stockholder Meetings

Our certificate of incorporation provides that, subject to the rights of the holders of any series of preferred stock, special meetings of our stockholders may be called at any time only by or at the direction of our board of directors by the affirmative vote of a majority of the total number of directors then in office, the chairman of our board of directors or our Chief Executive Officer, and may not be called by any other person or persons. Our bylaws prohibit the conduct of any business at a special meeting other than as specified in the notice for such meeting. These provisions may have the effect of deterring, delaying or discouraging hostile takeovers, or changes in control or management of the Company.

Director Nominations and Stockholder Proposals

Our bylaws establish advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors, other than nominations made by or at the direction of the board of directors or a committee of the board of directors. In order for any matter to be "properly brought" before a meeting, a stockholder will have to comply with advance notice requirements and provide us with certain information. Generally, to be timely, a stockholder's notice must be received at our principal executive offices not later than the close of business on the 90th day nor earlier than the close of business on the 120th day prior to the first anniversary date of the immediately preceding annual meeting of stockholders. Our bylaws also specify requirements as to the form and content of a stockholder's notice. Our bylaws allow the chairman of the meeting at a meeting of the stockholders to adopt rules and regulations for the conduct of meetings which may have the effect of precluding the conduct of certain business at a meeting if the rules and regulations are not followed. These provisions may also defer, delay or discourage a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to influence or obtain control of the Company.

Stockholder Action by Written Consent

Under the DGCL, any action required to be taken at any annual or special meeting of the stockholders may be taken without a meeting, without prior notice and without a vote if a consent or consents in writing, setting forth the action so taken, is or are signed by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares of our stock entitled to vote thereon were present and voted, unless our certificate of incorporation provides otherwise. Our certificate of incorporation precludes stockholder action by written consent at any time when BNAC and its affiliates and subsidiaries (excluding the Company and its subsidiaries) own, in the aggregate, less than 35% in voting power of our stock entitled to vote generally in the election of directors.

Supermajority Provisions

Our governing documents provide that our board of directors is expressly authorized to make, repeal, alter, amend and rescind, in whole or in part, our bylaws by the affirmative vote of a majority of the total number of directors then in office, without the assent or vote of the stockholders in any matter not inconsistent with the laws of the State of Delaware or our certificate of incorporation. Any amendment, alteration, rescission or repeal of any provision of our bylaws, or the adoption of any provision inconsistent with our bylaws, by our stockholders requires the affirmative vote of the holders of at least 66⅔% in voting power of all the then-outstanding shares of our stock entitled to vote thereon, voting together as a single class, in addition to any vote of the holders of any class or series of our capital stock required by our governing documents or applicable law or securities exchange rule or regulation.

The DGCL provides generally that the affirmative vote of a majority of the outstanding shares entitled to vote thereon, voting together as a single class, is required to amend a corporation's certificate of incorporation, unless the certificate of incorporation requires a greater percentage.

Our certificate of incorporation provides that, in addition to any vote required by our governing documents or applicable law or securities exchange rule or regulation, the following provisions in our certificate of incorporation may be amended, altered, repealed or rescinded, in whole or in part, or any provision inconsistent therewith may be adopted, only by the affirmative vote of the holders of at least 66⅔% in voting power all the then-outstanding shares of our stock entitled to vote thereon, voting together as a single class (except that, in the case of any proposed amendment, alteration, repeal or rescission of, or the adoption of any provision inconsistent with, the following provisions, as to which the DGCL does not require the consent or vote of the stockholders or that is approved by at least 60% of our board of directors, then only the affirmative vote of the holders of a majority in voting power of all the then-outstanding shares of our stock entitled to vote thereon, voting together as a single class (in addition to any vote required by our governing documents or applicable law or securities exchange rule or regulation), will be required to amend, alter, repeal or rescind, or adopt any provision inconsistent with, the following provisions:

- the provisions requiring a 66⅔% supermajority vote for stockholders to amend our bylaws;
- the provisions providing for a classified board of directors (the election and term of our directors);
- the provisions regarding removal of directors;
- the provisions regarding filling vacancies on our board of directors and newly-created directorships;
- the provisions eliminating monetary damages for breaches of fiduciary duty by a director or officer;

- the provisions regarding indemnification and advancement of expenses to certain indemnitees in connection with certain proceedings;
- the provisions regarding stockholder action by written consent;
- the provisions regarding calling special meetings of stockholders;
- the provisions regarding competition and corporate opportunities; and
- the amendment provision requiring that the above provisions be amended with a majority vote or a 66⅔% supermajority vote, as applicable, of stockholders.

The combination of the classification of our board of directors, the lack of cumulative voting and the supermajority voting requirements in certain circumstances will make it more difficult for our existing stockholders to replace our board of directors as well as for another party to obtain control of us by replacing our board of directors. Because our board of directors has the power to retain and discharge our officers, these provisions could also make it more difficult for existing stockholders or another party to effect a change in management.

These provisions may have the effect of deterring hostile takeovers or delaying or preventing changes in control of us or our management, such as a merger, reorganization or tender offer. These provisions are intended to enhance the likelihood of continued stability in the composition of our board of directors and its policies and to discourage certain types of transactions that may involve an actual or threatened acquisition of the Company. These provisions are designed to reduce our vulnerability to an unsolicited acquisition proposal. The provisions are also intended to discourage certain tactics that may be used in proxy fights. However, such provisions could have the effect of discouraging others from making tender offers for our shares and, as a consequence, they also may inhibit fluctuations in the market price of our shares that could result from actual or rumored takeover attempts. Such provisions may also have the effect of preventing changes in management.

Dissenters' Rights of Appraisal and Payment

Under the DGCL, with certain exceptions, our stockholders will have appraisal rights in connection with a merger or consolidation of the Company. Pursuant to the DGCL, stockholders who properly request and perfect appraisal rights in connection with such merger or consolidation will have the right to receive payment of the fair value of their shares as determined by the Delaware Court of Chancery.

Stockholders' Derivative Actions

Under the DGCL, any of our stockholders may bring an action in our name to procure a judgment in our favor, also known as a derivative action, provided that the stockholder bringing the action is a holder of our shares at the time of the transaction to which the action relates or such stockholder's stock thereafter devolved by operation of law.

Choice of Forums

Our certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by law, be the sole and exclusive forum for any (i) derivative action or proceeding brought on behalf of the Company, (ii) action asserting a claim of breach of a fiduciary duty owed by any director, officer or employee of the Company to the Company or our stockholders, (iii) action asserting a claim against the Company or any director or officer of the Company arising pursuant to any provision of the DGCL or our governing documents, or (iv) action asserting a claim against the Company or any director, officer or employee of the Company, which claim is governed by the internal affairs doctrine. Notwithstanding the foregoing sentence, the federal district courts of the United States of America will be the exclusive forum for the resolution of any complaint asserting a cause of action arising under U.S. federal securities laws, including the Securities Act and the Exchange Act. Any person or entity purchasing or otherwise acquiring any interest in shares of capital stock of the Company will be deemed to have notice of and consented to the forum provisions in our certificate of incorporation. However, the enforceability of similar forum provisions in other companies' certificates of incorporation has been challenged in legal proceedings, and it is possible that a court could find these types of provisions to be unenforceable.

Corporate Opportunity

The DGCL permits corporations to adopt provisions renouncing any interest or expectancy of the corporation in, or in being offered an opportunity to participate in, specified business opportunities that are presented to the corporation or its officers, directors or stockholders. Our certificate of incorporation, to the fullest extent permitted by law, renounces any interest or expectancy that we have in, or right to be offered an opportunity to participate in, specified business opportunities that are from time to time presented to our officers, directors or stockholders or their respective affiliates, other than those officers, directors, stockholders or affiliates who are our or our subsidiaries' employees. Our certificate of incorporation provides that, to the fullest extent permitted by law, neither BNAC nor its affiliates or any director who is not employed by us (including any non-employee director who serves as one of our officers in both his or her director and officer capacities) or his or her affiliates will have any duty to refrain from (i) engaging in the same or similar business activities or lines of business in which we or our affiliates now engage or propose to engage or (ii) otherwise competing with us or our affiliates. In addition, to the fullest extent permitted by law, in the event that BNAC or its affiliates or any non-employee director acquires knowledge of a potential transaction or other business opportunity that may be a corporate opportunity for itself, himself or herself or its or his or her affiliates or for us or any of our affiliates, such person will have no duty to communicate or offer such transaction or business opportunity to us or any of our affiliates and they may take any such opportunity for themselves or offer it to another person or entity. Our certificate of incorporation does not renounce our interest in any corporate opportunity that is expressly offered to a non-employee director solely in his or her capacity as a director or officer of the Company. To the fullest extent permitted by law, a business opportunity will not be deemed to be a potential corporate opportunity for us if we would not be financially or legally able, or contractually permitted to undertake, the opportunity; the opportunity, from its nature, would not be in the line of our business; or the opportunity is one in which we would have no interest or reasonable expectancy.

Limitations of Liability and Indemnification

The DGCL authorizes corporations to limit or eliminate the personal liability of directors to corporations and their stockholders for monetary damages for breaches of directors' fiduciary duties, subject to certain exceptions. Our certificate of incorporation includes a provision that eliminates the personal liability of our directors and officers for monetary damages to the Company or its stockholders for any breach of fiduciary duty as a director or an officer, to the fullest extent permitted by the DGCL. The effect of these provisions is to eliminate the rights of us and our stockholders, through stockholders' derivative suits on our behalf, to recover monetary damages from a director or an officer for breach of fiduciary duty as a director or an officer, including breaches resulting from grossly negligent behavior. However, exculpation does not apply to any breaches of the duty of loyalty, any acts or omissions not in good faith or that involve intentional misconduct or knowing violation of law, any authorization of dividends or stock redemptions or repurchases paid or made in violation of the DGCL, or for any transaction from which the director derived an improper personal benefit.

Our certificate of incorporation and our bylaws generally provide that we must defend, indemnify and advance expenses to our directors and officers to the fullest extent permitted by the DGCL. We also are expressly authorized to carry directors' and officers' liability insurance providing indemnification for our directors, officers and certain employees for some liabilities. We believe that these indemnification and advancement provisions and insurance are useful to attract and retain qualified directors and executive officers.

The limitation of liability, indemnification and advancement provisions in our certificate of incorporation and our bylaws may discourage stockholders from bringing a lawsuit against directors or officers for breach of their fiduciary duty. These provisions also may have the effect of reducing the likelihood of derivative litigation against directors and officers, even though such an action, if successful, might otherwise benefit us and our stockholders. In addition, your investment may be adversely affected to the extent we pay the costs of settlement and damage awards against directors and officers pursuant to these indemnification provisions.

There is currently no pending material litigation or proceeding involving any of our directors, officers or employees for which indemnification is sought.

Indemnification Agreements

We intend to enter into an indemnification agreement with each of our directors and officers as described in "*Certain Relationships and Related Party Transactions — Indemnification Agreements with our Directors and Officers*." Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors or officers, we have been informed that in the opinion of the SEC such indemnification is against public policy and is therefore unenforceable.

Registration Rights

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets and with certain piggyback rights. Our Stockholders' Agreement will also provide that we will pay certain expenses of BNAC and its affiliates relating to such registrations and indemnify them against certain liabilities that may arise under the Securities Act. See "*Certain Relationships and Related Party Transactions — Registration Rights*" for a description of these registration rights.

Transfer Agent and Registrar

Upon completion of this offering, the transfer agent and registrar for our common stock will be Broadridge Corporate Issuer Solutions, Inc. The transfer agent and registrar's address is 51 Mercedes Way, Edgewood, New York 11717.

Listing

We have applied to list our common stock on the NYSE under the symbol "BKV."

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock, and we cannot predict the effect, if any, that market sales of shares of our common stock or the availability of shares of our common stock for sale will have on the market price of our common stock prevailing from time to time. Future sales of our common stock in the public market, or the perception that those sales may occur, could adversely affect the prevailing market price of our common stock at such time, which could make it more difficult for you to sell your shares of common stock at a time and price that you consider appropriate, and could impair our ability to raise equity capital or use our common stock as consideration for acquisitions of other businesses, investments or other corporate purposes in the future.

Sale of Restricted Securities

Immediately upon completion of this offering, there will be outstanding shares of common stock (or if the underwriters exercise in full their option to purchase additional shares). Of these outstanding shares, shares of our common stock to be sold in this offering (or shares if the underwriters exercise in full their option to purchase additional shares) will be freely tradable without further restriction or registration under the Securities Act. Any shares purchased in this offering by our affiliates, as that term is defined in Rule 144 under the Securities Act, may be sold in the public market only if registered or if they qualify for an exemption from registration under Rule 144 or Rule 701 under the Securities Act, which rules are summarized below.

BNAC's shares of common stock will be deemed "restricted securities" as defined in Rule 144 under the Securities Act. These restricted securities may be sold in the public market only if they are registered or if they qualify for an exemption from registration under Rule 144 under the Securities Act. BNAC will agree to certain lock-up restrictions with the underwriters pursuant to which it will agree, subject to specific exceptions, not to sell any of our stock for 180 days following the date of this prospectus. See "— *Lock-Up Arrangements*" below and "*Underwriting*."

As a result of the lock-up agreements described below and the provisions of Rule 144 and Rule 701 under the Securities Act, the shares of our common stock (excluding the shares to be sold in this offering) that will be available for sale in the public market are as follows:

- no shares will be eligible for sale on the date of this prospectus or prior to 180 days after the date of this prospectus; and
- shares will be eligible for sale upon the expiration of the lock-up agreements beginning 180 days after the date of this prospectus and when permitted under Rule 144 or Rule 701.

Lock-Up Arrangements

In connection with the completion of this offering, BNAC and all of our directors and executive officers will enter into lock-up agreements with the underwriters pursuant to which they will agree not to offer, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend or otherwise transfer or dispose of, directly or indirectly, any shares of common stock or any securities convertible into or exercisable or exchangeable for shares of common stock for a period of at least 180 days following the date of this prospectus, subject to certain exceptions. As a result of these contractual restrictions, shares of our common stock and the other securities subject to lock-up agreements will not be eligible for sale until these agreements expire or the restrictions are waived by the underwriters. The representatives of the underwriters may, in their discretion, release any of the securities subject to lock-up restrictions with the underwriters in whole or in part at any time. See "*Underwriting*."

Shares of our common stock which were issued in satisfaction of awards granted under the 2021 Plan are subject to resale restrictions. The holder may not, without the consent of the Company or the representatives of the underwriters (for 180 days from the date of the final prospectus), (1) sell, pledge, offer to sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase or otherwise transfer or dispose of, any shares of common stock or any securities convertible into or exercisable or exchangeable for common stock, or (2) enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock. See "*Executive Compensation — BKV Corporation 2021 Long Term Incentive Plan*."

Rule 144

In general, under Rule 144 as in effect on the date of this prospectus, once we have been subject to public company reporting requirements for at least 90 days, a person who has beneficially owned shares proposed to be sold for at least six months, including the holding period of any prior owner other than an affiliate of us, and who is not deemed to have been one of our affiliates for purposes of the Securities Act at any time during the 90 days preceding a sale, will be entitled to sell, upon expiration of the lock-up agreements described above, such shares without complying with the manner of sale, volume limitation or notice provisions of Rule 144, subject to compliance with the public information requirements of Rule 144. Such a non-affiliated person who has beneficially owned the shares proposed to be sold for at least one year, including the holding period of any prior owner other than an affiliate of us, will be entitled to sell these shares without limitation.

In general, under Rule 144, our affiliates or persons selling shares on behalf of our affiliates will be entitled to sell upon expiration of the 180-day lock-up period described above, within any three-month period, a number of shares that does not exceed the greater of:

- 1% of the number of shares of our common stock then outstanding, which will equal approximately shares immediately after this offering (or shares if the underwriters elect to exercise in full their option to purchase additional shares); or
- the average weekly trading volume of our common stock on the NYSE during the four calendar weeks before a notice of the sale is filed on Form 144 with respect to such sale.

Sales by our affiliates or persons selling shares on behalf of our affiliates under Rule 144 also are subject to manner of sale and notice provisions and to the availability of public information about us.

Rule 701

In general, under Rule 701 under the Securities Act, any of our employees, directors, officers, consultants or advisors who purchases shares from us in connection with a compensatory stock or option plan or other written agreement before the effective date of this offering is entitled to sell such shares 90 days after the effective date of this offering in reliance on Rule 144, without having to comply with the holding period requirement of Rule 144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

Registration Statement on Form S-8

We intend to file with the SEC a registration statement on Form S-8 under the Securities Act promptly after the completion of this offering to register shares of our common stock subject to equity-based incentive awards which were granted under the 2021 Plan, and which are reserved for future issuance under our 2022 Plan. See "*Executive Compensation — BKV Corporation 2021 Long Term Incentive Plan*" and "*Executive Compensation — BKV Corporation 2022 Equity and Incentive Compensation Plan*." The Form S-8 will also register shares of our common stock reserved for future purchase under our 2022 Employee Stock Purchase Plan. See "*Executive Compensation — BKV Corporation Employee Stock Purchase Plan*." The registration statement on Form S-8 is expected to become effective immediately upon filing, and shares of our common stock covered by the registration statement will then become eligible for sale in the public market, subject to the Rule 144 limitations applicable to affiliates and vesting restrictions. See "*Executive Compensation — BKV Corporation 2021 Long Term Incentive Plan,*" "*Executive Compensation — BKV Corporation 2022 Equity and Incentive Compensation Plan*" and "*Executive Compensation — BKV Corporation Employee Stock Purchase Plan.*"

Registration Rights

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets at any time following the date that is six months after the consummation of this offering. BNAC and its affiliates will also be entitled to certain piggyback rights with respect to future registrations or underwritten shelf takedowns, subject to certain limitations. "*Certain Relationships and Related Party Transactions — Registration Rights*" contains additional information regarding such rights.

CERTAIN ERISA CONSIDERATIONS

The following is a summary of certain considerations associated with the acquisition and holding of shares of our common stock by employee benefit plans that are subject to Title I of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), plans, individual retirement accounts and other arrangements that are subject to Section 4975 of the Code or employee benefit plans that are governmental plans (as defined in Section 3(32) of ERISA), certain church plans (as defined in Section 3(33) of ERISA), non-U.S. plans (as described in Section 4(b)(4) of ERISA) or other plans that are not subject to the foregoing but may be subject to provisions under any other federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of ERISA or the Code (collectively, "Similar Laws"), and entities whose underlying assets are considered to include "plan assets" of any such plan, account or arrangement (each, a "Plan").

This summary is based on the provisions of ERISA and the Code (and related regulations and administrative and judicial interpretations) as of the date of this registration statement. This summary does not purport to be complete, and no assurance can be given that future legislation, court decisions, regulations, rulings or pronouncements will not significantly modify the requirements summarized below. Any of these changes may be retroactive and may thereby apply to transactions entered into prior to the date of their enactment or release. This discussion is general in nature and is not intended to be all inclusive, nor should it be construed as investment or legal advice.

General Fiduciary Matters

ERISA and the Code impose certain duties on persons who are fiduciaries of a Plan subject to Title I of ERISA or Section 4975 of the Code (an "ERISA Plan") and prohibit certain transactions involving the assets of an ERISA Plan and its fiduciaries or other interested parties. Under ERISA and the Code, any person who exercises any discretionary authority or control over the administration of an ERISA Plan or the management or disposition of the assets of an ERISA Plan, or who renders investment advice for a fee or other compensation to an ERISA Plan, is generally considered to be a fiduciary of the ERISA Plan.

In considering an investment in shares of our common stock with a portion of the assets of any Plan, a fiduciary should consider the Plan's particular circumstances and all of the facts and circumstances of the investment and determine whether the acquisition and holding of shares of our common stock is in accordance with the documents and instruments governing the Plan and the applicable provisions of ERISA, the Code, or any Similar Law relating to the fiduciary's duties to the Plan, including, without limitation:

- 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 ERISA Plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;
- whether the investment is permitted under the terms of the applicable documents governing the Plan;
- whether in the future there may be no market in which to sell or otherwise dispose of the shares of our common stock;
- whether the acquisition or holding of the shares of our common stock will constitute a "prohibited transaction" under Section 406 of ERISA or Section 4975 of the Code (see discussion under "— *Prohibited Transaction Issues*"); and
- whether the Plan will be considered to hold, as plan assets, (i) only shares of our common stock or (ii) an undivided interest in our underlying assets (see the discussion under "— *Plan Asset Issues*").

Prohibited Transaction Issues

Section 406 of ERISA and Section 4975 of the Code prohibit ERISA Plans from engaging in specified transactions involving plan assets with persons or entities who are "parties in interest," within the meaning of ERISA, or "disqualified persons," within the meaning of Section 4975 of the 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 Code. In addition, the fiduciary of the ERISA Plan that engages in such a non-exempt prohibited transaction may be subject to excise taxes, penalties and liabilities under ERISA and the Code. The acquisition and/or holding of shares of our common stock by an ERISA Plan with respect to which the issuer, the initial purchaser, or a guarantor is considered a party in interest or a disqualified person may constitute or result in a direct or indirect prohibited transaction under Section 406 of ERISA and/or Section 4975 of the Code, unless the investment is acquired and is held in accordance with an applicable statutory, class or individual prohibited transaction exemption.

Because of the foregoing, shares of our common stock should not be acquired or held by any person investing "plan assets" of any Plan, unless such acquisition and holding will not constitute a non-exempt prohibited transaction under ERISA and the Code or a similar violation of any applicable Similar Laws.

Plan Asset Issues

Additionally, a fiduciary of a Plan should consider whether the Plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that we would become a fiduciary of the 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 Code and any other applicable Similar Laws.

The Department of Labor (the "DOL") regulations provide guidance with respect to whether the assets of an entity in which ERISA Plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets generally would not be considered to be "plan assets" if, among other things:

(a) the equity interests acquired by ERISA Plans are "publicly offered securities" (as defined in the DOL regulations) — *i.e.*, the equity interests are part of a class of securities that is widely held by 100 or more investors independent of the issuer and each other, are freely transferable, and are either registered under certain provisions of the federal securities laws or sold to the ERISA Plan as part of a public offering under certain conditions;

(b) the entity is an "operating company" (as defined in the DOL regulations) — *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

(c) there is no significant investment by "benefit plan investors" (as defined in the DOL regulations) — *i.e.*, immediately after the most recent acquisition by an ERISA Plan of any equity interest in the entity, less than 25% of the total value of each class of equity interest (disregarding certain interests held by persons (other than benefit plan investors) with discretionary authority or control over the assets of the entity or who provide investment advice for a fee (direct or indirect) with respect to such assets, and any affiliates thereof) is held by ERISA Plans, individual retirement accounts and certain other Plans (but not including governmental plans, foreign plans and certain church plans), and entities whose underlying assets are deemed to include plan assets by reason of a Plan's investment in the entity.

Due to the complexity of these rules and the excise taxes, penalties and liabilities that may be imposed upon persons involved in non-exempt prohibited transactions, it is particularly important that fiduciaries, or other persons considering acquiring and/or holding shares of our common stock on behalf of, or with the assets of, any Plan, consult with their counsel regarding the potential applicability of ERISA, Section 4975 of the Code and any Similar Laws to such investment and whether an exemption would be applicable to the acquisition and holding of shares of our common stock. Purchasers of shares of our common stock have the exclusive responsibility for ensuring that their acquisition and holding of shares of our common stock complies with the fiduciary responsibility rules of ERISA and does not violate the prohibited transaction rules of ERISA, the Code or applicable Similar Laws. The sale of shares of our common stock to a Plan is in no respect a representation by us or any of our affiliates or representatives that such an investment meets all relevant legal requirements with respect to investments by any such Plan or that such investment is appropriate for any such Plan.

MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES TO NON-U.S. HOLDERS OF OUR COMMON STOCK

The following is a general discussion of material U.S. federal income tax consequences to non-U.S. holders (as defined herein) with respect to the ownership and disposition of our common stock. This discussion applies only to non-U.S. holders that acquire our common stock in this offering and hold such stock as a capital asset within the meaning of Section 1221 of the Code (generally, property held for investment purposes). This discussion is based on current provisions of the Code, U.S. Treasury regulations promulgated under the Code, and administrative rulings and court decisions in effect, all of which are subject to change at any time, possibly with retroactive effect. We have not sought and will not seek any rulings from the IRS regarding the matters discussed below.

For purposes of this discussion, the term "non-U.S. holder" means a beneficial owner of our common stock that is not, for U.S. federal income tax purposes, an entity or arrangement treated as a partnership or any of the following:

- a citizen or individual resident of the United States;
- a corporation, or other entity treated as a corporation for U.S. federal income tax purposes, created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust (1) if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more "United States persons" (as defined in Section 7701(a)(30) of the Code) has or have the authority to control all substantial decisions of the trust, or (2) that has a valid election in effect under applicable U.S. Treasury regulations to be treated as a "United States person."

This discussion is for general information only and does not address all aspects of U.S. federal income taxation that may be important to a non-U.S. holder in light of that holder's particular circumstances or that may be applicable to holders subject to special treatment under U.S. federal income tax law (including, for example, financial institutions, brokers or dealers in securities, traders in securities that elect mark-to-market treatment, insurance companies, controlled foreign corporations, passive investment companies, holders who acquire our common stock pursuant to the exercise of employee stock options or otherwise as compensation, entities or arrangements treated as partnerships for U.S. federal income tax purposes (and partners or beneficial owners therein), holders liable for the alternative minimum tax, certain former citizens or former long-term residents of the U.S., persons who hold or are deemed to hold our common stock as part of a hedge, straddle, constructive sale, conversion transaction or other risk-reduction transaction, persons required for U.S. federal income tax purposes to conform the timing of income accruals with respect to the common stock to their financial statements under Section 451 of the Code, tax-qualified retirement plans, tax-exempt organizations, and governmental organizations, and "qualified foreign pension funds" as defined in Section 897(l)(2) of the Code and entities all of the interests of which are held by qualified foreign pension funds). In addition, this discussion does not address U.S. federal tax laws other than those pertaining to the U.S. federal income tax, nor does it address any aspects of the Medicare contribution tax on net investment income, or U.S. state or local or non-U.S. taxes. This discussion also does not specifically address any tax treaties. Accordingly, prospective investors should consult their own tax advisors regarding the U.S. federal, state, local, and non-U.S. income and other tax considerations of acquiring, holding and disposing of shares of our common stock.

If a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership generally will depend upon the status of the partner, the activities of the partnership and certain determinations made at the partner level. Accordingly, we urge partners in partnerships (including entities or arrangements treated as partnerships for U.S. federal income tax purposes) considering the purchase of our common stock to consult their tax advisors regarding the U.S. federal income tax considerations of the ownership and disposition of our common stock by such partnership.

THIS SUMMARY IS FOR GENERAL INFORMATION ONLY. IT IS NOT TAX ADVICE. INVESTORS CONSIDERING THE PURCHASE OF OUR COMMON STOCK ARE URGED TO

CONSULT THEIR TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL, STATE, LOCAL AND NON-U.S. INCOME AND OTHER TAX LAWS AND ANY APPLICABLE TAX TREATIES TO THEIR PARTICULAR SITUATIONS.

Distributions on Common Stock

At or prior to the closing of this offering, our board of directors will adopt a policy pursuant to which we intend to pay dividends to stockholders.

In general, any distributions we make to a non-U.S. holder with respect to shares of our common stock that constitute dividends for U.S. federal income tax purposes will be subject to U.S. withholding tax at a rate of 30% (or such lower rate as may be specified by an applicable income tax treaty) of the gross amount distributed, unless the dividends are effectively connected with a trade or business carried on by the non-U.S. holder within the United States and, if required by an applicable income tax treaty, are attributable to a permanent establishment of the non-U.S. holder within the United States. A distribution will constitute a dividend for U.S. federal income tax purposes to the extent of our current or accumulated earnings and profits as determined for U.S. federal income tax purposes. Any distribution not constituting a dividend will be treated as first reducing the adjusted basis in the non-U.S. holder's shares of our common stock, but not below zero, and, to the extent it exceeds the adjusted basis in the non-U.S. holder's shares of our common stock, as capital gain and will be treated as described below under "— *Sale, Exchange or Other Taxable Disposition of Common Stock*." However, except to the extent that we elect (or the paying agent or other intermediary through which you hold your shares of common stock elects) to withhold with respect to the taxable portion of the distribution only, we (or the applicable paying agent or intermediary) must generally withhold on the entire distribution, in which case you generally would be entitled to a refund from the IRS by timely filing an appropriate claim for a refund, to the extent the withholding exceeds your tax liability with respect to the distribution.

A non-U.S. holder who wishes to claim the benefit of an applicable treaty rate on dividends will be required (a) to provide the applicable withholding agent with a properly executed IRS Form W-8BEN or W-8BEN-E (or other applicable form) certifying under penalties of perjury that such holder is not a U.S. person as defined under the Code and is eligible for treaty benefits or (b) if our common stock is held through certain foreign intermediaries, to satisfy the relevant certification requirements of applicable U.S. Treasury regulations. A non-U.S. holder that does not timely furnish the required documentation, but that is eligible for a lower rate of U.S. federal withholding tax pursuant to an income tax treaty, may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for a refund with the IRS. Non-U.S. holders are urged to consult their own tax advisors regarding their possible entitlement to benefits under an applicable income tax treaty.

Dividends effectively connected with a non-U.S. holder's conduct of a U.S. trade or business (and, if required by an applicable income tax treaty, attributable to such non-U.S. holder's U.S. permanent establishment) generally will not be subject to U.S. withholding tax if the non-U.S. holder complies with applicable certification requirements. More particularly, to claim this exemption from U.S. withholding tax, the non-U.S. holder must furnish to the applicable withholding agent a valid IRS Form W-8ECI, certifying that the dividends are effectively connected with the non-U.S. holder's conduct of a trade or business within the United States. Such effectively connected dividends, although not subject to withholding tax (provided the IRS Form W-8ECI certification requirements are satisfied), generally will be subject to U.S. federal income tax on a net income basis, at the regular graduated rates applicable to U.S. persons. A non-U.S. holder that is a corporation may be subject to an additional "branch profits tax" at a rate of 30% (or such lower rate as may be specified by an applicable income tax treaty) on its "effectively connected earnings and profits," subject to certain adjustments.

The foregoing is subject to the discussion below under "— *Information Reporting and Backup Withholding*" and "— *Foreign Account Tax Compliance Act*."

Sale, Exchange or Other Taxable Disposition of Common Stock

Subject to the discussion below under "— *Information Reporting and Backup Withholding*" and "— *Foreign Account Tax Compliance Act*," a non-U.S. holder will generally not be subject to U.S. federal income or withholding tax with respect to gain recognized on the sale, exchange or other taxable disposition of our common stock unless:

- the gain is effectively connected with a trade or business carried on by the non-U.S. holder within the United States and, if required by an applicable income tax treaty, is attributable to a U.S. permanent establishment of such non-U.S. holder,
- the non-U.S. holder is a nonresident alien individual and is present in the United States for 183 days or more in the taxable year of the sale, exchange or other taxable disposition and certain other conditions are satisfied, or
- we are or have been a "United States real property holding corporation" ("USRPHC") for U.S. federal income tax purposes at any time within the shorter of the five-year period ending on the date of the disposition of the common stock and the non-U.S. holder's holding period, and certain other conditions are satisfied.

Gain described in the first bullet point above (*i.e.*, gain that is effectively connected with the conduct of a trade or business in the United States) generally will be subject to U.S. federal income tax, net of certain deductions, at the regular graduated rates applicable to U.S. persons. If the non-U.S. holder is a foreign corporation, the branch profits tax at a rate of 30% (or such lower rate as may be specified by an applicable income tax treaty) also may apply to such effectively connected gain.

A non-U.S. holder described in the second bullet point above (*i.e.*, who is subject to U.S. federal income tax because the non-U.S. holder was present in the United States for 183 days or more during the taxable year of the sale, exchange or other taxable disposition of our common stock) will be subject to U.S. federal income tax at a rate of 30% (or such lower rate as may be specified under an applicable income tax treaty) on the gain derived from such sale, exchange or other taxable disposition, which may be offset by U.S. source capital losses, provided the non-U.S. holder has timely filed U.S. federal income tax returns with respect to such losses.

With respect to the third bullet point above, we are currently, and expect to continue to be for the foreseeable future, a USRPHC (and the remainder of this discussion assumes we are and will be a USRPHC). However, if our common stock is "regularly traded on an established securities market" (as defined by the U.S. Treasury regulations), a non-U.S. holder will be taxed on gain recognized on the disposition of our common stock as a result of our status as a USRPHC only if the non-U.S. holder actually or constructively holds or held more than 5% of our common stock at any time during the five-year period ending on the date of disposition or, if shorter, during the entire period the non-U.S. holder has held our common stock. If our common stock were not considered to be regularly traded on an established securities market, all non-U.S. holders would be subject to U.S. federal income tax on the sale, exchange or other taxable disposition of our common stock and a 15% withholding tax would apply to the gross proceeds from such sale, exchange or other taxable disposition of our common stock by a non-U.S. holder. Such withholding tax is not an additional tax but, rather, is credited against the actual U.S. federal income taxes owed by the non-U.S. holder (and such non-U.S. holder may obtain a refund of any amounts so withheld which exceed the non-U.S. holder's actual U.S. federal income tax liability, if any, provided that the non-U.S. holder makes the necessary filings with the IRS in a timely manner).

Information Reporting and Backup Withholding

We (or the applicable paying agent or intermediary) must report annually to the IRS and to each non-U.S. holder the amount of distributions paid to, and the tax withheld (if any) with respect to, each non-U.S. holder of our common stock. These reporting requirements apply regardless of whether withholding was reduced or eliminated by an applicable tax treaty. Copies of this information also may be made available under the provisions of a specific treaty or agreement with the tax authorities in the country in which the non-U.S. holder resides or is established.

U.S. backup withholding tax, at a rate that is currently 24%, is imposed on certain payments to persons that fail to furnish the information required under the U.S. information reporting rules. Dividends paid to a non-U.S. holder generally will be exempt from backup withholding if the non-U.S. holder provides a properly executed applicable IRS Form W-8, or otherwise establishes an exemption.

Under U.S. Treasury regulations, the payment of proceeds from the disposition of our common stock by a non-U.S. holder effected at a U.S. office of any broker (U.S. or non-U.S.), generally will be subject to information reporting and backup withholding, unless the beneficial owner certifies its status as a non-U.S. holder (generally by providing a properly executed applicable IRS Form W-8), or otherwise establishes an exemption. The payment of proceeds from the disposition of our common stock by a non-U.S. holder effected at a non-U.S. office of a broker that is neither a U.S. person nor a person having certain relationships with the United States generally will not be subject to backup withholding or information reporting. However, the payment of proceeds from a disposition of our common stock by a non-U.S. holder effected at a non-U.S. office of a broker that is a U.S. person or has certain relationships with the United States will generally be subject to information reporting, unless the beneficial owner certifies its status as a non-U.S. holder (generally by providing a properly executed applicable IRS Form W-8), or the broker has other documentary evidence in its files that the beneficial owner is a non-U.S. holder and certain other conditions are satisfied, or the beneficial owner otherwise establishes an exemption (and the broker has no knowledge or reason to know to the contrary). If the payment described in the preceding sentence is subject to information reporting, it will be subject to backup withholding if the broker has actual knowledge or reason to know that the payee is a U.S. person.

Backup withholding is not an additional tax but, rather, is credited against the actual U.S. federal income taxes owed by the non-U.S. holder. A non-U.S. holder may obtain a refund of any amounts withheld under the backup withholding rules which exceed the non-U.S. holder’s actual U.S. federal income tax liability, if any, provided that the non-U.S. holder makes the necessary filings with the IRS in a timely manner.

Foreign Account Tax Compliance Act

Under Sections 1471 through 1474 of the Code and the U.S. Treasury regulations promulgated thereunder (collectively, “FATCA”), a U.S. federal withholding tax of 30% generally will be imposed on certain payments made to a “foreign financial institution” (as specifically defined under these rules) unless such institution enters into an agreement with the U.S. tax authorities to withhold on certain payments and to collect and provide to the U.S. tax authorities substantial information regarding U.S. account holders of such institution or meets other exceptions. Under FATCA and administrative guidance, a U.S. federal withholding tax of 30% generally also will be imposed on certain payments made to a “non-financial foreign entity” (as specifically defined under these rules) unless such entity provides the withholding agent with a certification identifying its direct and indirect U.S. owners or meets other exceptions. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the U.S. governing these withholding and reporting requirements may be subject to different rules.

These withholding taxes would be imposed on dividends with respect to our common stock to foreign financial institutions or non-financial foreign entities (including in their capacity as agents or custodians for beneficial owners of our common stock) that fail to satisfy the above requirements. Prior to the issuance of proposed U.S. Treasury regulations, withholding taxes under FATCA also would have applied to gross proceeds from the disposition of our common stock. However, the proposed U.S. Treasury regulations provide that such gross proceeds are generally not subject to withholding taxes under FATCA. Taxpayers (including withholding agents) may currently rely on these proposed U.S. Treasury regulations until they are revoked or final U.S. Treasury regulations are issued.

Under certain circumstances, a non-U.S. holder might be eligible for refunds or credits of such taxes. Prospective non-U.S. holders should consult their tax advisors regarding the possible implications of FATCA on their investment in our common stock.

UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated as of the date of this prospectus (the "Underwriting Agreement"), we have agreed to sell to the underwriters named below, for whom Credit Suisse Securities (USA) LLC, BofA Securities, Inc. and Barclays Capital Inc. are acting as representatives, the following respective numbers of shares of common stock:

Underwriter	Number of Shares
Credit Suisse Securities (USA) LLC	
BofA Securities, Inc.	
Barclays Capital Inc.	
Citigroup Global Markets Inc.	
Evercore Group L.L.C.	
Jefferies LLC	
Tudor, Pickering, Holt & Co. Securities, LLC	
Susquehanna Financial Group, LLLP	
SMBC Nikko Securities America, Inc.	
Total	

The Underwriting Agreement provides that the underwriters are obligated to purchase all the shares of common stock in the offering if any are purchased, other than those shares covered by the over-allotment option described below. The Underwriting Agreement also provides that if an underwriter defaults the purchase commitments of non-defaulting underwriters may be increased or the offering may be terminated.

We have agreed to indemnify the underwriters and certain of their controlling persons against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make in respect of those liabilities.

We have granted to the underwriters a 30-day option to purchase on a pro rata basis up to additional shares at the initial public offering price less the underwriting discounts and commissions. The option may be exercised only to cover any over-allotments of common stock.

The underwriters propose to offer the shares of common stock initially at the public offering price on the cover page of this prospectus and to selling group members at that price less a selling concession of up to $ per share. After the initial public offering the underwriters may change the public offering price and concession.

The following table summarizes the underwriting discounts and commissions payable by us to the underwriters in connection with this offering, assuming both no exercise and full exercise of the underwriters' over-allotment option.

	Per Share		Total	
	Without Over-allotment	With Over-allotment	Without Over-allotment	With Over-allotment
Underwriting discounts and commissions payable by us	$	$	$	$

The expenses of this offering that have been paid or are payable by us are estimated to be approximately $ million (excluding underwriting discounts and commissions). We have also agreed to reimburse the underwriters for certain of their expenses incurred in connection with this offering in an amount up to $.

We have agreed that, subject to certain exceptions, we will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, or file with the SEC a registration statement under the Securities Act relating to, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, or publicly disclose the intention to make any offer, sale, pledge, disposition or filing, without the prior written consent of the representatives for a period of 180 days after the date of this prospectus.

The representatives of the underwriters may, in their discretion, release the shares of our common stock or other securities subject to the lock-up agreements described above in whole or in part at any time.

Our officers and directors and certain of our stockholders have agreed that they will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, enter into a transaction that would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of our common stock, whether any of these transactions are to be settled by delivery of our common stock or other securities, in cash or otherwise, or publicly disclose the intention to make any such offer, sale, pledge or disposition, or to enter into any such transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of the representatives for a period of 180 days after the date of this prospectus, subject to certain exceptions.

We have applied to list our common stock on the NYSE under the symbol “BKV.”

In connection with the listing of the common stock on the NYSE, the underwriters will undertake to sell round lots of 100 shares or more to a minimum of 400 beneficial owners.

Prior to this offering, there has been no public market for our common stock. The initial public offering price was determined by negotiations among us and the representatives and will not necessarily reflect the market price of the common stock following this offering. The principal factors that were considered in determining the initial public offering price included:

- the information presented in this prospectus and otherwise available to the underwriters;
- the history of, and prospects for, the industry in which we will compete;
- the ability of our management;
- the prospects for our future earnings;
- the present state of our development, results of operations and our current financial condition;
- the general condition of the securities markets at the time of this offering; and
- the recent market prices of, and the demand for, publicly traded common stock of generally comparable companies.

We cannot assure you that the initial public offering price will correspond to the price at which the common stock will trade in the public market subsequent to this offering or that an active trading market for the common stock will develop and continue after this offering.

In connection with the offering the underwriters may engage in stabilizing transactions, over-allotment transactions, syndicate covering transactions and penalty bids in accordance with Regulation M under the Exchange Act.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- Over-allotment involves sales by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of shares over-allotted by the underwriters is not greater than the number of shares that they may purchase in the over-allotment option. In a naked short position, the number of shares involved is greater than the number of shares in the over-allotment option. The underwriters may close out any covered short position by either exercising their over-allotment option and/or purchasing shares in the open market.
- Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the

source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through the over-allotment option. If the underwriters sell more shares than could be covered by the over-allotment option, a naked short position, the position can only be closed out by buying shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

- Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing transaction or a syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result, the price of our common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NYSE or otherwise and, if commenced, may be discontinued at any time.

The underwriters and certain of their affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. The underwriters and certain of their affiliates have, from time to time, performed, and may in the future perform, various commercial and investment banking and financial advisory services for the issuer and its affiliates, for which they received, or may in the future receive, customary fees and expenses.

In the ordinary course of their various business activities, the underwriters and certain of 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, and such investment and securities activities may involve securities and/or instruments of the issuer or its affiliates. If the underwriters or their affiliates have a lending relationship with us, certain of those underwriters or their affiliates may hedge their credit exposure to us consistent with their customary risk management policies. Typically, the underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities or the securities of our affiliates, including potentially the shares of common stock offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the shares of common stock offered hereby. The underwriters and certain of their affiliates may also communicate independent investment recommendations, market color or trading ideas and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

A prospectus in electronic format will be made available on the web sites maintained by one or more of the underwriters, or selling group members, if any, participating in this offering and one or more of the underwriters participating in this offering may distribute prospectuses electronically. The representatives may agree to allocate a number of shares to underwriters and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by the underwriters and selling group members that will make internet distributions on the same basis as other allocations.

Notice to Prospective Investors in Canada

The common stock may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the common stock must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 (or, in the case of securities issued or guaranteed by the government of a non-Canadian jurisdiction, section 3A.4) of National Instrument 33-105 Underwriting Conflicts, or NI 33-105, the underwriter is not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

Notice to Prospective Investors in the European Economic Area

In relation to each Member State of the European Economic Area (each an "EEA State"), no common stock has been offered or will be offered pursuant to the offering to the public in that EEA State prior to the publication of a prospectus in relation to the common stock which has been approved by the competent authority in that EEA State or, where appropriate, approved in another EEA State and notified to the competent authority in that EEA State, all in accordance with the EU Prospectus Regulation, except that it may make an offer to the public in that EEA State of any shares of common stock at any time under the following exemptions under the EU Prospectus Regulation:

- to any legal entity which is a qualified investor as defined under the EU Prospectus Regulation;
- to fewer than 150 natural or legal persons (other than qualified investors as defined under the EU Prospectus Regulation), subject to obtaining the prior consent of Credit Suisse Securities (USA) LLC for any such offer; or
- in any other circumstances falling within Article 1(4) of the EU Prospectus Regulation,

provided that no such offer of the common stock shall require the Issuer or any underwriter to publish a prospectus pursuant to Article 3 of the EU Prospectus Regulation or supplement a prospectus pursuant to Article 23 of the EU Prospectus Regulation.

For the purposes of this provision, the expression an "offer to the public" in relation to the common stock in any EEA State means the communication in any form and by any means of sufficient information on the terms of the offer and any shares of common stock to be offered so as to enable an investor to decide to purchase or subscribe for any shares of common stock, and the expression "EU Prospectus Regulation" means Regulation (EU) 2017/1129.

Notice to Prospective Investors in the United Kingdom

In relation to the United Kingdom, no shares of common stock have been offered or will be offered pursuant to the offering to the public in the United Kingdom prior to the publication of a prospectus in relation to the common stock which has been approved by the Financial Conduct Authority in accordance with the transitional provision in Regulation 74 of the Prospectus (Amendment etc.) (EU Exit) Regulations 2019, except that it may make an offer to the public in the United Kingdom of any shares of common stock at any time under the following exemptions under the UK Prospectus Regulation:

- to any legal entity which is a qualified investor as defined under the UK Prospectus Regulation;
- to fewer than 150 natural or legal persons (other than qualified investors as defined under the UK Prospectus Regulation), subject to obtaining the prior consent of the representatives for any such offer; or
- in any other circumstances falling within Section 86 of the Financial Services and Markets Act 2000 (the "FSMA"),

provided that no such offer of the common stock shall require the Issuer or any underwriter to publish a prospectus pursuant to Section 85 of the FSMA or supplement a prospectus pursuant to Article 23 of the UK Prospectus Regulation.

In the United Kingdom, the offering is only addressed to, and is directed only at, "qualified investors" within the meaning of Article 2(e) of the UK Prospectus Regulation, who are also (i) persons having professional experience in matters relating to investments who fall within the definition of "investment professionals" in Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order"); (ii) high net worth bodies corporate, unincorporated associations and partnerships and trustees of high value trusts as described in Article 49(2) of the Order; or (iii) persons to whom it may otherwise lawfully be communicated (all such persons being referred to as "relevant persons"). This document must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this document relates is available only to relevant persons and will be engaged in only with relevant persons.

For the purposes of this provision, the expression an "offer to the public" in relation to the common stock in the United Kingdom means the communication in any form and by any means of sufficient information on the terms of the offering and any shares of common stock to be offered so as to enable an investor to decide to purchase or subscribe for any shares of common stock, and the expression "UK Prospectus Regulation" means the UK version of Regulation (EU) No 2017/1129 as amended by The Prospectus (Amendment etc.) (EU Exit) Regulations 2019, which is part of UK law by virtue of the European Union (Withdrawal) Act 2018.

Notice to Prospective Investors in the Dubai International Financial Centre

This prospectus relates to an Exempt Offer in accordance with the Offered Securities Rules of the Dubai Financial Services Authority (the "DFSA"). This prospectus is intended for distribution only to persons of a type specified in the Offered Securities Rules of the DFSA. It must not be delivered to, or relied on by, any other person. The DFSA has no responsibility for reviewing or verifying any documents in connection with Exempt Offers. The DFSA has not approved this prospectus nor taken steps to verify the information set forth herein and has no responsibility for the prospectus. The securities to which this prospectus relates may be illiquid and/or subject to restrictions on their resale. Prospective purchasers of the securities offered should conduct their own due diligence on the securities. If you do not understand the contents of this prospectus you should consult an authorized financial advisor.

Notice to Prospective Investors in Australia

No placement document, prospectus, product disclosure statement or other disclosure document has been lodged with the Australian Securities and Investments Commission, in relation to the offering. This prospectus does not constitute a prospectus, product disclosure statement or other disclosure document under the Corporations Act 2001 (the "Corporations Act"), and does not purport to include the information required for a prospectus, product disclosure statement or other disclosure document under the Corporations Act.

Any offer in Australia of the securities may only be made to persons (the "Exempt Investors") who are "sophisticated investors" (within the meaning of section 708(8) of the Corporations Act), "professional investors" (within the meaning of section 708(11) of the Corporations Act) or otherwise pursuant to one or more exemptions contained in section 708 of the Corporations Act so that it is lawful to offer the securities without disclosure to investors under Chapter 6D of the Corporations Act.

The securities applied for by Exempt Investors in Australia must not be offered for sale in Australia in the period of 12 months after the date of allotment under the offering, except in circumstances where disclosure to investors under Chapter 6D of the Corporations Act would not be required pursuant to an exemption under section 708 of the Corporations Act or otherwise or where the offer is pursuant to a disclosure document which complies with Chapter 6D of the Corporations Act. Any person acquiring securities must observe such Australian on-sale restrictions. This prospectus contains general information only and does not take account of the investment objectives, financial situation or particular needs of any particular person. It does not contain any securities recommendations or financial product advice. Before making an investment decision, investors need to consider whether the information in this prospectus is appropriate to their needs, objectives and circumstances, and, if necessary, seek expert advice on those matters.

Notice to Prospective Investors in Switzerland

The common stock may not be publicly offered, directly or indirectly, in Switzerland within the meaning of the Swiss Financial Services Act (the “FinSA”) and no application has or will be made to admit the common stock to trading on any trading venue (exchange or multilateral trading facility) in Switzerland. Neither this prospectus nor any other offering or marketing material relating to the common stock constitutes a prospectus pursuant to the FinSA, and neither this prospectus nor any other offering or marketing material relating to the common stock may be publicly distributed or otherwise made publicly available in Switzerland.

Notice to Prospective Investors in Hong Kong

The common stock may not be offered or sold in Hong Kong by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong), or (ii) to “professional investors” within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a “prospectus” within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong) and no advertisement, invitation or document relating to the common stock may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to common stock which are or are intended to be disposed of only to persons outside Hong Kong or only to “professional investors” within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Notice to Prospective Investors in Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the common stock may not be circulated or distributed, nor may the common stock be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the “SFA”), (ii) to a relevant person pursuant to Section 275(1), or any person pursuant to Section 275(1A), and in accordance with the conditions specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA, in each case subject to compliance with conditions set forth in the SFA.

Solely for the purposes of its obligations pursuant to sections 309B(1)(a) and 309B(1)(c) of the SFA and the Securities and Futures (Capital Markets Products) Regulations 2018 of Singapore (the “CMP Regulations 2018”), the Issuer has determined, and hereby notifies all relevant persons (as defined in Section 309A of the SFA) that the shares of common stock are (A) prescribed capital markets products (as defined in the CMP Regulations 2018) and (B) Excluded Investment Products (as defined in MAS Notice SFA 04-N12: Notice on the Sale of Investment Products and MAS Notice FAA-N16: Notice on Recommendations on Investment Products).

Notice to Prospective Investors in Thailand

This prospectus does not, and is not intended to, constitute a public offering in Thailand. The common stock may not be offered or sold to persons in Thailand, unless such offering is made under the exemptions from approval and filing requirements under applicable laws, or under circumstances which do not constitute an offer for sale of the common stock to the public for the purposes of the Securities and Exchange Act of 1992 of Thailand, nor require approval from the Office of the Securities and Exchange Commission of Thailand.

Where the shares of common stock are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

- a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or
- a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor,

shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust will not be transferred within six months after that corporation or that trust has acquired the shares pursuant to an offer made under Section 275 of the SFA except:

- to an institutional investor (for corporations, under Section 274 of the SFA) or to a relevant person defined in Section 275(2) of the SFA, or to any person pursuant to an offer that is made on terms that such shares, debentures and units of shares and debentures of that corporation or such rights and interest in that trust are acquired at a consideration of not less than S$200,000 (or its equivalent in a foreign currency) for each transaction, whether such amount is to be paid for in cash or by exchange of securities or other assets, and further for corporations, in accordance with the conditions specified in Section 275 of the SFA;
- where no consideration is or will be given for the transfer; or
- where the transfer is by operation of law.

LEGAL MATTERS

The validity of the common stock offered hereby and certain other legal matters in connection with this offering will be passed upon for us by Baker Botts L.L.P., Dallas, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas. Baker Botts L.L.P. has from time to time represented and may continue to represent BKV and some of its affiliates in connection with various legal matters.

EXPERTS

The consolidated financial statements of BKV Corporation as of December 31, 2022 and 2021 and for each of the three years in the period ended December 31, 2022 included in this prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP ("PwC"), an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

In connection with this registration statement, PwC completed an independence assessment to evaluate the services and relationships with the Company and its affiliates that may bear on PwC's independence under the SEC and the PCAOB independence rules for an audit period commencing January 1, 2020. PwC informed the Company's Audit & Risks Committee that one of its member firms within PricewaterhouseCoopers International Limited, each member firm of which is a separate legal entity (a "PwC member firm"), provided non-audit services during the audit period to two sister entities under common control with BKV Corporation. The services that occurred from January 2020 to June 2021, which are inconsistent with the SEC and PCAOB independence rules, involved the provision of corporate secretarial services and the disbursement of incidental payments on behalf of client management. The fees for these services totaled approximately $8,500 and $10,000, respectively, for the years ended December 31, 2021 and 2020. The provision of corporate secretarial services and the incidental payments made on behalf of client management are in contravention of SEC Rule 2-01(c)(4)(vi) of Regulation S-X.

PwC informed the Company's Audit & Risks Committee of the facts and circumstances surrounding the impermissible services, noting that (i) the PwC member firm did not make any decisions or judgments on management's behalf, and management reviewed and approved all documentation prepared by the PwC member firm, (ii) no aspect of the financial results of the sister entities or the provision of the services is included in (or has any impact on) the financial results of the Company, (iii) the services were performed by persons who were not part of the PwC audit engagement team, and (iv) the fees for the services were not material to the Company, the sister entities, the PwC member firm, or PwC. Additionally, the services do not create a mutual or conflicting interest between PwC and the Company, do not place PwC in a position of auditing its own work, and do not place PwC in a position of being an advocate for the Company.

After considering the facts and circumstances, the Company's Audit & Risks Committee concurred with PwC's conclusion that, for the reasons described above, the impermissible services did not impair PwC's objectivity and impartiality with respect to the planning and execution of the audits of the Company's consolidated financial statements as of December 31, 2022 and 2021 and for each of the three years in the period ended December 31, 2022, and that no reasonable investor would conclude otherwise.

The statements of revenues and direct operating expenses of the Barnett Assets of XTO Energy Inc. and Barnett Gathering, LLC for the years ended December 31, 2021 and 2020 included in this prospectus have been so included in reliance on the report (which contained an explanatory paragraph relating to the basis of presentation of the statements of revenues and direct operating expenses as described in "*Note 1*" to the financial statements) of PricewaterhouseCoopers LLP, independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

Estimates of our natural gas reserves, related future net cash flows and the present values thereof related to our properties as of December 31, 2022, 2021 and 2020 included elsewhere in this prospectus were based upon reserve reports prepared by independent petroleum engineers Ryder Scott Company, L.P. We have included these estimates in reliance on the authority of such firms as experts in such matters.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 under the Securities Act with respect to the shares of common stock offered by this prospectus. This prospectus, which constitutes a part of the registration statement, does not contain all of the information set forth in the registration statement, some of which is contained in exhibits to the registration statement as permitted by the rules and regulations of the SEC. For further information with respect to us and our common stock, we refer you to the registration statement, including the exhibits filed as part of the registration statement. Statements contained in this prospectus concerning the contents of any contract or any other document are not necessarily complete, and each such statement is qualified in all respects by reference to the full text of such contract or other document filed as an exhibit to the registration statement.

The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *www.sec.gov*. Our filings with the SEC, including the registration statement, are available to you for free on the SEC's internet website.

Upon completion of this offering, we will become subject to the informational and reporting requirements of the Exchange Act and, in accordance with those requirements, will file reports and proxy and information statements with the SEC. We intend to furnish to our stockholders our annual reports containing audited consolidated financial statements and the notes thereto certified by an independent public accounting firm.

We also maintain an internet website at *www.bkvcorp.com*. Information on or accessible through our website is not part of this prospectus.

INDEX TO FINANCIAL STATEMENTS

BKV CORPORATION

Audited Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of BKV Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of BKV Corporation and its subsidiaries (the “Company”) as of December 31, 2022 and 2021, and the related consolidated statements of operations, of stockholders’ equity, partners’ capital and mezzanine equity and of cash flows for each of the three years in the period ended December 31, 2022, including the related notes (collectively referred to as the “consolidated 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 each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
April 13, 2023

We have served as the Company’s auditor since 2020.

BKV Corporation

Consolidated Balance Sheets
(In thousands, except per share amounts)

	December 31, 2022	December 31, 2021
Assets		
Current assets		
Cash and cash equivalents	$ 153,128	$ 134,667
Accounts receivable, net	143,537	104,143
Accounts receivable, related party	416	3,498
Other current assets	23,059	19,070
Total current assets	320,140	261,378
Natural gas properties and equipment		
Developed properties	2,252,681	1,378,629
Undeveloped properties	15,511	16,835
Midstream assets	317,109	55,363
Accumulated depreciation, depletion, and amortization	(375,783)	(274,710)
Total natural gas properties, net	2,209,518	1,176,117
Other property and equipment, net	39,865	22,124
Goodwill	18,417	18,417
Investment in joint venture	97,885	89,320
Deferred tax asset, net	—	35,504
Other noncurrent assets	16,748	17,968
Total assets	$2,702,573	$1,620,828
Liabilities, mezzanine equity, and stockholders’ equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 272,475	$ 166,836
Contingent consideration payable	65,000	65,000
Commodity derivative liabilities	49,484	91,156
Income taxes payable to related party	5,227	30,660
Notes payable to related party	—	166,000
Credit facilities	90,000	—
Current portion of long-term debt, net	112,001	—
Other current liabilities	2,446	10,713
Total current liabilities	596,633	530,365
Asset retirement obligations	181,135	158,968
Contingent consideration	88,051	142,533
Commodity derivative liabilities	—	23,662
Note payable to related party	75,000	—
Deferred tax liability, net	104,130	—
Long-term debt, net	452,036	—
Other noncurrent liabilities	9,664	10,361
Total liabilities	1,506,649	865,889

The accompanying notes are an integral part of these consolidated financial statements.

BKV Corporation

Consolidated Balance Sheets
(In thousands, except per share amounts)

	December 31, 2022	December 31, 2021
Commitments and contingencies (*Note 16*)		
Mezzanine equity		
Common stock – Minority ownership puttable shares; 4,581 authorized shares; 4,581 and 4,357 shares issued and outstanding as of December 31, 2022 and 2021, respectively	62,712	49,841
Equity-based compensation	89,171	34,006
Total mezzanine equity	151,883	83,847
Stockholders' equity		
Common stock, $.01 par value; 300,000 authorized shares; 112,745 and 112,745 shares issued and outstanding as of December 31, 2022 and 2021, respectively	1,132	1,132
Treasury stock, shares at cost; 386 shares and 385 shares as of December 31, 2022 and 2021, respectively	(3,974)	(3,970)
Additional paid-in capital	896,433	933,622
Retained earnings (deficit)	150,450	(259,692)
Total stockholders' equity	1,044,041	671,092
Total liabilities, mezzanine equity, and stockholders' equity	$2,702,573	$1,620,828

The accompanying notes are an integral part of these consolidated financial statements.

BKV Corporation

Consolidated Statements of Operations
(In thousands, except per share amounts)

	Year Ended December 31,		
	2022	**2021**	**2020**
Revenues and other operating income			
Natural gas, NGL, and oil sales	$1,633,747	$ 829,745	$115,043
Midstream revenues	12,676	6,917	7,458
Derivative gains (losses), net	(629,701)	(383,847)	20,755
Marketing revenues	11,001	52,616	—
Related party and other	2,799	251	33
Total revenues and other operating income	1,030,522	505,682	143,289
Operating expenses			
Lease operating and workover	135,064	88,105	31,260
Taxes other than income	114,668	45,650	5,151
Gathering and transportation	208,758	173,587	—
Depreciation, depletion, amortization, and accretion	118,909	92,277	87,343
General and administrative	148,559	85,740	29,442
Total operating expenses	725,958	485,359	153,196
Income (loss) from operations	304,564	20,323	(9,907)
Other income and expense			
Bargain purchase gain	170,853	—	—
Gain on settlement of litigation	16,866	—	—
Gain (loss) on contingent consideration liabilities	6,632	(194,968)	7,135
Earnings from equity affiliate	8,493	910	—
Interest income	1,143	8	121
Interest expense	(26,322)	—	—
Interest expense, related party	(10,846)	(2,134)	(1,713)
Other income	1,411	872	—
Income (loss) before income taxes	472,794	(174,989)	(4,364)
Income tax benefit (expense)	(62,652)	40,526	(38,982)
Net income (loss) attributable to BKV Corporation	410,142	(134,463)	(43,346)
Less accretion of preferred stock to redemption value	—	(3,745)	—
Less preferred stock dividends	—	(9,900)	(460)
Less deemed dividend on redemption of preferred stock	—	(22,606)	—
Net income (loss) attributable to common stockholders	$ 410,142	$(170,714)	$ (43,806)
Net income (loss) per common share:			
Basic	$ 3.50	$ (1.46)	$ (0.42)
Diluted	$ 3.31	$ (1.46)	$ (0.42)
Weighted average number of common shares outstanding:			
Basic	117,318	116,904	105,275
Diluted	123,980	116,904	105,275

The accompanying notes are an integral part of these consolidated financial statements.

BKV Corporation

Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31, 2022	2021	2020
Cash flows from operating activities:			
Net income (loss)	$ 410,142	$(134,463)	$ (43,346)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization, and accretion	130,038	98,833	90,191
Equity-based compensation expense	31,947	30,387	—
Deferred income tax expense (benefit)	89,065	(72,753)	37,750
Unrealized (gains) losses on derivatives, net	(58,815)	115,161	(10,329)
(Gains) losses on contingent consideration liabilities	(6,632)	194,968	(7,135)
Settlement of contingent consideration	(45,300)	—	—
Gain on bargain purchase	(170,853)	—	—
Earnings from equity affiliates	(8,493)	(910)	—
Other, net	911	48	—
Changes in operating assets and liabilities:			
Accounts receivable, net	(39,394)	(24,689)	(44,480)
Accounts receivable, related parties	3,082	(3,498)	—
Prepaid expenses	(4,371)	(339)	(1,628)
Inventory	(6,585)	(2,097)	(95)
Other noncurrent assets	(573)	(1,030)	92
Accounts payable and accrued liabilities	62,539	137,550	(25,221)
Lease liabilities	(11,919)	(7,313)	(3,910)
Income taxes payable to related party	(25,433)	29,443	1,217
Payable to related party	—	—	(511)
Asset retirement expenditures	(162)	(1,165)	—
Net cash provided by (used in) operating activities	349,194	358,133	(7,405)
Cash flows from investing activities:			
Business combination	(619,437)	—	311
Investment in joint venture	(72)	(88,410)	—
Acquisition of natural gas properties	—	(2,528)	(501,712)
Acquisition of undeveloped natural gas properties	(290)	(5,024)	(2,064)
Investment in other property and equipment	(11,787)	(2,249)	(1,187)
Investment in midstream assets	(904)	—	—
Development of natural gas properties	(235,406)	(63,932)	(9,340)
Proceeds from the sale of other property and equipment	2,330	285	—
Net cash used in investing activities	(865,566)	(161,858)	(513,992)
Cash flows from financing activities:			
Proceeds from notes payable from related party	75,000	166,000	129,000
Payments on notes payable to related party	(166,000)	(24,000)	(105,000)
Proceeds under term loan agreement	570,000	—	—
Payment of debt issuance costs	(7,738)	—	—
Proceeds from draws on credit facilities	190,000	—	—
Payments on credit facilities	(100,000)	—	—
Settlement of contingent consideration	(19,700)	—	—
Payments of deferred offering costs	(5,625)	—	—

The accompanying notes are an integral part of these consolidated financial statements.

BKV Corporation

Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31, 2022	2021	2020
Proceeds from the issuance of common stock and other equity contributions	—	—	323,799
Redemption of minority ownership puttable shares	—	(2,754)	—
Issuance of minority ownership puttable shares	78	3,177	—
Dividends paid to preferred stock shareholders	—	(10,330)	—
Redemption of preferred stock	—	(121,275)	—
Proceeds from the issuance of preferred stock, net	—	—	94,924
Dividends paid to common stock shareholders	—	(88,126)	—
Redemption of common stock	—	(1,106)	—
Purchase of common stock issued through equity-based compensation plan	(4)	(110)	—
Net share settlements, equity-based compensation	(1,178)	(529)	—
Net cash provided by (used in) financing activities	534,833	(79,053)	442,723
Net increase (decrease) in cash and cash equivalents	18,461	117,222	(78,674)
Cash and cash equivalents, beginning of period	134,667	17,445	96,119
Cash and cash equivalents, end of period	$ 153,128	$ 134,667	$ 17,445

	Year Ended December 31, 2022	2021	2020
Supplemental cash flow information:			
Cash payments for:			
Interest	$32,086	$ 393	$ 1,523
Income tax	$ 400	$ —	$ —
Non-cash investing and financing activities:			
Increase (decrease) in accrued capital expenditures	$19,247	$12,297	$ (1,377)
Additions to asset retirement obligations	$ 302	$ 923	$ 772
Revisions to asset retirement obligation estimates	$36,516	$ —	$ —
Additions to operating assets and liabilities for business combination, net of cash acquired	$ —	$ —	$ 19,689
Lease liabilities arising from obtaining right-of-use assets	$ 1,218	$11,249	$ 7,093
Deferred offering costs included in accounts payable and accrued liabilities	$ 945	$ —	$ —
Fair value of contingent consideration from acquisitions	$17,150	$ —	$ 19,700
Adjustment of minority ownership puttable shares to redemption value	$12,793	$ 7,042	$ —
Adjustment of equity-based compensation to redemption value	$24,400	$ 4,236	$ —
Impact of redemption of minority interest puttable shares on additional paid-in capital, common stock and treasury stock	$ 4	$ 2,754	$ —
Accretion of preferred stock to redemption value	$ —	$ 3,745	$ —

The accompanying notes are an integral part of these consolidated financial statements.

BKV Corporation

Consolidated Statements of Stockholders’ Equity, Partners’ Capital, and Mezzanine Equity
(In thousands, except per share amounts)

	Stockholders’ Equity							Mezzanine Equity				
	Common Stock								Common Stock			
	Shares	Amount	Treasury	Additional Paid-in Capital	Retained Earnings (Deficit)	Total Stockholders’ Equity	Total Partners’ Capital	Preferred Stock	Shares	Amount	Equity-based Compensation	Total Mezzanine Equity
Balances, January 1, 2020	—	$ —	$ —	$ —	$ —	$ —	$ 684,190	$ —	—	$ —	$ —	$ —
Contributed capital	—	—	—	—	—	—	100,000	—	—	—	—	—
Net loss	—	—	—	—	(26,773)	(26,773)	(16,573)	—	—	—	—	—
Corporatization	90,471	905	—	744,424	—	745,329	(767,617)	—	2,229	22,288	—	22,288
Shares issued in business combination	—	—	—	—	—	—	—	—	2,000	20,000	—	20,000
Issuance of common stock	22,384	224	—	223,575	—	223,799	—	—	—	—	—	—
Issuance of preferred stock	—	—	—	—	—	—	—	94,924	—	—	—	94,924
Other, net	—	—	—	501	—	501	—	—	—	—	—	—
Balances, December 31, 2020	112,855	$1,129	$ —	$968,500	$ (26,773)	$ 942,856	$ —	$ 94,924	4,229	$42,288	$ —	$137,212
Net loss	—	—	—	—	(134,463)	(134,463)	—	—	—	—	—	—
Dividend declared, preferred stock shareholders ($0.25 per share)	—	—	—	—	(10,330)	(10,330)	—	—	—	—	—	—
Accretion of preferred stock to redemption value	—	—	—	(3,745)	—	(3,745)	—	3,745	—	—	—	3,745
Deemed dividend, preferred stock shareholders	—	—	—	(22,606)	—	(22,606)	—	—	—	—	—	—
Redemption of preferred stock	—	—	—	—	—	—	—	(98,669)	—	—	—	(98,669)
Redemption of common stock	(100)	—	(1,106)	—	—	(1,106)	—	—	—	—	—	—
Purchase of vested equity-based compensation award shares of common stock	(10)	—	(110)	—	—	(110)	—	—	—	—	—	—
Redemption of minority ownership puttable common stock shares	—	3	(2,754)	2,751	—	—	—	—	(275)	(2,754)	—	(2,754)
Dividend declared ($0.75 per share)	—	—	—	—	(88,126)	(88,126)	—	—	—	—	—	—
Issuance of common stock from employee stock purchase plan	—	—	—	—	—	—	—	—	287	3,265	—	3,265
Adjustment of minority ownership puttable shares to redemption value	—	—	—	(7,042)	—	(7,042)	—	—	—	7,042	—	7,042
Issuance of common stock upon vesting of equity-based compensation awards	—	—	—	—	—	—	—	—	116	—	—	—
Impact of modification of equity-based compensation plan	—	—	—	—	—	—	—	—	—	—	25,342	25,342
Capital contribution from modification of equity-based compensation plan	—	—	—	780	—	780	—	—	—	—	—	—
Equity-based compensation	—	—	—	—	—	—	—	—	—	—	3,648	3,648
Adjustment of equity-based compensation to redemption value	—	—	—	(5,016)	—	(5,016)	—	—	—	—	5,016	5,016
Balances, December 31, 2021	112,745	$1,132	$(3,970)	$933,622	$(259,692)	$ 671,092	$ —	$ —	4,357	$49,841	$34,006	$ 83,847
Net income	—	—	—	—	410,142	410,142		—	—	—	—	—
Redemption of common stock issued upon vesting of equity-based compensation	—	—	(4)	4	—	—	—	—	—	—	(4)	(4)
Issuance of common stock from employee stock purchase plan	—	—	—	—	—	—	—	—	5	78	—	78

The accompanying notes are an integral part of these consolidated financial statements.

BKV Corporation

Consolidated Statements of Stockholders' Equity, Partners' Capital, and Mezzanine Equity
(In thousands, except per share amounts)

	Stockholders' Equity							Mezzanine Equity				
	Common Stock								Common Stock			
	Shares	Amount	Treasury	Additional Paid-in Capital	Retained Earnings (Deficit)	Total Stockholders' Equity	Total Partners' Capital	Preferred Stock	Shares	Amount	Equity-based Compensation	Total Mezzanine Equity
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	—	—	—	—	—	—	—	—	219	—	(1,178)	(1,178)
Adjustment of minority ownership puttable shares to redemption value	—	—	—	(12,793)	—	(12,793)	—	—	—	12,793	—	12,793
Adjustment of equity-based compensation to redemption value	—	—	—	(24,400)	—	(24,400)	—	—	—	—	24,400	24,400
Equity-based compensation	—	—	—	—	—	—	—	—	—	—	31,947	31,947
Balances, December 31, 2022	112,745	$1,132	$(3,974)	$896,433	$150,450	$1,044,041	$ —	$ —	4,581	$62,712	$89,171	$151,883

The accompanying notes are an integral part of these consolidated financial statements.

BKV Corporation

Notes to the Consolidated Financial Statements

Note 1 — Business and Basis of Presentation

Business

BKV Corporation ("BKV Corp") was formed on May 1, 2020 and is a corporation registered with the State of Delaware. BKV Corp is a growth driven energy company focused on creating value for its shareholders through organic development of its properties, as well as accretive acquisitions. BKV Corp's core business is to produce natural gas from its owned and operated upstream businesses.

Upon its incorporation, BKV Corp entered into certain agreements to acquire the net assets of BKV Oil and Gas Capital Partners, L.P. ("BKV O&G") in a common control transaction. BKV Corp also entered into a transaction to acquire Kalnin Ventures LLC ("KV") in a business combination. These two transactions resulted in the corporate restructuring of BKV Corp. The associated series of transactions further described in *Note 3 — Acquisitions and Other Related Activity* are collectively referred to as the "Corporatization Event." The change in reporting entity under common control requires retrospective presentation of BKV O&G and BKV for the period presented as if the change had been in effect since the beginning of the period being presented. Accordingly, the accompanying consolidated statements of operations for the year ended December 31, 2020 represents the consolidation of BKV O&G's results of operations for the four months ended April 30, 2020 and BKV Corp's results of operations for the eight months ended December 31, 2020.

The majority shareholder of BKV Corp is Banpu North America Corporation ("BNAC"). BKV Corp's ultimate parent company is Banpu Public Company Limited, a public company listed in the Stock Exchange of Thailand. As of April 13, 2023, the date these consolidated financial statements were available to be issued, BNAC owned 95.9% of BKV Corp's shares. The remaining 4.1% of shares of common stock of BKV Corp were owned by non-controlling members of management, members of the Board of Directors ("Directors"), and employee and non-employee shareholders who hold shares with contingent put rights that may be exercised according to conditions stipulated in the agreement among these shareholders, BNAC, and BKV Corp (the "Stockholders' Agreement").

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts for BKV Corp's wholly-owned subsidiaries. Prior years' financial statement amounts have been reclassified in certain cases to conform with the presentation of the consolidated financial statements for the year ended December 31, 2022. As of December 31, 2021, these amounts primarily included related party accounts receivable, prepaid expenses, inventory, and commodity derivative assets, which have been reclassified to other current assets on the consolidated balance sheets. In addition, for the years ended December 31, 2021 and 2020, commodity derivative settlements receivable and payable was reclassified to accounts receivable, net and accounts payable and accrued liabilities, respectively, on the consolidated statements of cash flows.

During 2022, the following entities were formed as wholly-owned subsidiaries of BKV Corp:

- BKV Midstream, LLC ("Midstream"), a limited liability company formed March 31, 2022 and registered with the State of Delaware.
- BKV North Texas, LLC ("North Texas"), a limited liability company formed March 31, 2022 and registered with the State of Delaware.
- BKV dCarbon Ventures, LLC ("BKV dCarbon Ventures"), a limited liability company formed May 31, 2022 and registered with the State of Delaware;
    - BKVerde, LLC ("BKVerde"), a limited liability company formed August 1, 2022, registered with the State of Delaware, and a wholly-owned subsidiary of BKV dCarbon Ventures.

BKV Corporation

Notes to the Consolidated Financial Statements

Together, BKV Corp and its wholly-owned subsidiaries are referred to collectively as “BKV” or the “Company.” All intercompany balances and transactions between these entities have been eliminated within the consolidated financial statements. Current and deferred income taxes and related tax expense have been determined based on the stand-alone results of BKV by applying the separate return method to BKV’s operations as if it were a separate taxpayer.

On September 19, 2022, the Company dissolved BKV O&G, and all ownership interests in subsidiaries of BKV O&G were assigned to BKV Corp.

Liquidity

As of December 31, 2022, the Company held $153.1 million of cash and cash equivalents. The Company’s working capital deficit as of December 31, 2022 was $276.5 million, which was primarily driven by the current portion of long-term debt of $112.0 million, borrowings under the Company’s credit facilities of $90.0 million, contingent consideration payable of $65.0 million, and derivative monetizations payable of $57.0 million. For the year ended December 31, 2022, the Company’s cash flows from operations was $349.2 million. The Company intends to make the payments related to the current portion of long-term debt, the contingent consideration payable, and monetizations payable with cash flows from operations. The Company believes cash flows provided from operations and borrowings under its credit facilities are sufficient to meet cash requirements for the next twelve months and thereafter. As of the date these consolidated financial statements were available to be issued, the Company paid the $65.0 million of contingent consideration payable and the $90.0 million of borrowings under the Company’s credit facilities. Additional borrowings under the credit facilities after December 31, 2022 but before the date these consolidated financial statement were available to be issued are discussed in *Note 4 — Debt*.

In early 2023, natural gas prices began decreasing significantly from previous periods, which if sustained will cause non-compliance of the Company’s fixed charge coverage ratio financial covenant beginning with the quarter ending June 30, 2023 and subsequent quarters, and its net leverage ratio financial covenant for the quarter ending December 31, 2023, which covenants are discussed in *Note 4 — Debt* and *Note 15 — Credit and Other Risk.* Non-compliance with financial debt covenants will limit the Company’s ability to draw on its existing credit facilities and could also result in the Company’s debt agreements being called early, which would move certain non-current financial obligations to current. As a result, the Company would have insufficient liquidity and capital resources to be able to repay those obligations. Additionally, the Company’s reduced cash flow from operations could cause the Company not to meet its current and non-current financial obligations based on current forecasts. To alleviate these conditions the Company’s ultimate parent, Banpu Public Company Limited, has agreed to provide funding to allow the Company to meet its financial obligations until June 30, 2024, if necessary. The Company is also seeking waivers or amendments from lenders for certain debt covenants within the Term Loan Credit Agreement and revolving credit facility through several quarters into 2024 and is also seeking increased availability for borrowings under the Company’s existing credit facilities.

Note 2 — Summary of Significant Accounting Policies

Significant Judgments and Accounting Estimates

The preparation of these consolidated financial statements in accordance with GAAP for the periods presented requires Company management to make estimates using assumptions and judgements considered reasonable, which affect the consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to the Company’s consolidated financial statements include: (i) estimates of proved hydrocarbon reserves used in calculating depletion; (ii) estimates of unpaid revenues and unbilled costs; (iii) future cash flows from developed natural gas properties used in impairment assessments; (iv) valuation of commodity derivative instruments; (v) the estimation of asset retirement obligations; (vi) assignment of fair value to assets acquired and liabilities assumed in connection with acquisitions that are considered business combinations and allocating purchase price in connection with acquisitions that are considered asset acquisitions; (vii) valuation of minority ownership puttable shares; (viii) valuation of the Company's common stock relative to the grant date fair value of equity-based compensation; (ix) valuation of market-based performance conditions; (x) valuation of contingent consideration associated with certain acquired assets; and (xi) valuation of deferred income tax assets. While Management is not aware of any significant revisions to any of its current estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and natural gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period in which the adjustment occurs.

Principles of Consolidation

These consolidated financial statements include the accounts of BKV Corp and its wholly-owned subsidiaries. Accordingly, all intercompany balances and transactions between these entities have been eliminated within the consolidated financial statements. Undivided interests in natural gas properties and midstream assets are consolidated on a proportionate basis.

Comprehensive Income (Loss)

The Company did not have any other comprehensive income (loss) for the years ended December 31, 2022, 2021, and 2020. As such, net income (loss) and comprehensive income (loss) are the same for the periods presented.

Acquisitions

Business Combinations

If the assets acquired and liabilities assumed constitute a business, the transaction is accounted for as a business combination. This method requires the recognition of the acquired identifiable assets, assumed liabilities and any non-controlling interest in the companies acquired at their fair value.

The value of the purchase price may be finalized up to a maximum of one year from acquisition date.

The acquirer shall recognize goodwill at the acquisition date, being the excess of:

- The consideration transferred, the amount of non-controlling interests and, in business combinations achieved in stages, the fair value at acquisition date of the investment previously held in the acquired company;
- Over fair value at acquisition date of acquired identifiable assets and assumed liabilities.

Factors giving rise to goodwill generally include operational synergies that are anticipated as a result of the business combination and growth expected to result in economic benefits from access to new customers and markets. If the consideration transferred is lower than the fair value of acquired identifiable assets and assumed liabilities, an additional analysis is performed on the identification and valuation of the identifiable elements of the assets and liabilities. After having completed such additional analysis, including, if any, adjustments to provisional amounts recognized during the twelve months following the acquisition, any residual negative goodwill is recorded as a bargain purchase gain in the consolidated statements of operations. Subsequent changes to the fair value of contingent consideration are recorded in the other income and expense section of the consolidated statements of operations.

Asset Acquisitions

When substantially all of the gross assets acquired are concentrated in a single identifiable asset, or a group of similar identifiable assets, the acquisition is treated as an asset acquisition.

BKV Corporation

Notes to the Consolidated Financial Statements

The Company accounts for asset acquisitions by performing purchase price allocations wherein the total transaction value is determined by aggregating the base purchase price, certain closing adjustments, and contingent consideration, if any. The total transaction value is then allocated to the acquired assets pro-rata based on their fair values. This allocation may cause identified assets to be recognized at amounts that are greater than their fair values. However, “non-qualifying” assets, which include financial assets and other current assets, should not be assigned an amount greater than their fair value. The determination of fair values of assets acquired requires the Company to make estimates and use valuation techniques. The transaction costs associated with asset acquisitions are capitalized as part of the assets acquired. Subsequent changes to the fair value of contingent consideration are recorded in the other income and expense section of the consolidated statements of operations.

Cash and Cash Equivalents

Cash represents cash deposits held at financial institutions. Cash equivalents include short-term highly liquid investments of sufficient credit quality that are readily convertible to known amounts of cash and have original maturities of three months or less.

Inventory

Inventories are stated at the lower of cost or net realizable value. The cost of inventories is based upon the average cost method.

Income Taxes

The Company accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, the Company determines deferred tax assets and liabilities on the basis of the differences between the financial statement and tax bases of assets and liabilities by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

The Company regularly reviews its deferred tax assets for recoverability and establishes a valuation allowance if it is more likely than not that some portion, or all, of a deferred tax asset will not be realized. The determination as to whether a deferred tax asset will be realized is made on a jurisdictional basis and is based on both positive and negative evidence. This evidence includes historic taxable income, projected future taxable income, the expected timing of the reversal of existing temporary differences, and the implementation of tax planning strategies.

The Company records uncertain tax positions on the basis of a two-step process in which (i) the Company determines whether it is more-likely-than-not that the tax positions will be sustained on the basis of the technical merits of the position and (ii) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority.

The Company evaluates its tax positions that have been taken or are expected to be taken on income tax returns to determine if an accrual is necessary for uncertain tax positions. The Company recognizes interest and penalties as a component of tax expense. Refer to *Note 17 — Income Taxes* for further discussion.

Natural Gas Properties

The Company uses the successful efforts method of accounting for natural gas producing activities. Costs to acquire mineral interests in natural gas properties, to drill and equip exploratory leases that find proved reserves, and to drill and equip development leases and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized, or suspended, pending determination of whether the wells

BKV Corporation

Notes to the Consolidated Financial Statements

have proved reserves. If the Company determines the wells do not have proved reserves, the costs are charged to expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If the Company determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. There were no exploratory wells capitalized pending determinations of whether the wells have proved reserves as of December 31, 2022 and 2021. Geological and geophysical costs, including seismic studies and costs of carrying and retaining unproved properties, are charged to expense as incurred. The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to intended use. For the years ended December 31, 2022, 2021, and 2020, the Company had no capitalized interest costs. Costs incurred to maintain wells and related equipment are charged to expense as incurred. Capitalized amounts attributable to developed gas properties are depleted by the unit-of-production method over proved developed and undeveloped reserves.

The process of estimating natural gas, NGL, and oil reserves is complex and requires significant subjective decisions in the evaluation of all available geological, engineering, and economic data. These estimates are based on studies performed by the Company's internal engineering function and a third party reserve engineer.

Upon certain triggering events, capitalized costs related to proved gas properties, including wells and related support equipment and facilities, are evaluated for impairment by comparing the associated net capitalized cost to undiscounted future cash flows on a field by field basis. If undiscounted future cash flows are insufficient to recover the net capitalized costs related to proved properties, then the Company recognizes an impairment charge in its results of operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values. Estimating the fair value of the natural gas properties includes discounting the future net cash flows of the natural gas properties to arrive at a single amount. Significant assumptions included in the discounted cash flow model include natural gas properties reserves, estimated future operating and development cost, expectations of future commodity prices and a market based weighted average cost of capital discount rate. The Company had no impairment of proved properties during the years ended December 31, 2022, 2021, and 2020.

Undeveloped natural gas properties are tested for impairment on a regular basis, based on the results of the exploratory activity and management's evaluation. In the event of a discovery, the undeveloped natural gas properties are transferred to developed natural gas properties at net book value as soon as proved reserves are recognized. During the years ended December 31, 2022, 2021, and 2020, the Company recognized no impairments related to undeveloped natural gas properties.

Midstream Assets

Midstream assets are recorded at historical cost, less depreciation. Hydrocarbon transportation assets (midstream assets) are depreciated using the straight-line method over 25 years for compressor and meter stations, and 40 years for pipelines. Routine maintenance and repairs are charged to operating expenses as incurred. Realization of the carrying value of midstream assets is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the assets, including any disposal value, is less than the carrying amount of the assets. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on discounted future net operating cash flows related to the assets. There were no impairments recognized during the years ended December 31, 2022, 2021, and 2020.

BKV Corporation

Notes to the Consolidated Financial Statements

Other Property and Equipment

Other property and equipment is stated at cost, net of accumulated depreciation. Cost includes the purchase price and, where relevant, any costs directly attributable to bringing the asset to the location and condition necessary. When significant costs are incurred subsequent to the purchase of the asset that extends the life of the asset, such costs are included in the cost of the applicable asset and depreciated over their respective useful lives. All other subsequent costs are recognized in the consolidated statements of operations as either lease operating and workover expense or general and administrative expense.

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Fair value of other property and equipment is determined using the market approach. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. There were no material impairments recognized during the years ended December 31, 2022, 2021, and 2020.

Depreciation and amortization expense is included within Depreciation, depletion, and amortization on the consolidated statements of operations. Following is a listing of useful lives for other property and equipment:

	Useful Life
Buildings	39 years
Furniture, fixtures, equipment, vehicles, and other	5 years
Computer hardware and software	3 – 5 years
Leasehold improvements	7 – 10 years

Deferred Offering Costs

The Company has capitalized legal and other third party fees directly related to the Company's planned initial public offering ("IPO"). The deferred offering costs will be recorded as a reduction of the proceeds received from the IPO. If the IPO is abandoned or significantly delayed, the deferred offering costs will be expensed. As of December 31, 2021, the Company had no deferred offering costs that were capitalized. As of December 31, 2022, the Company capitalized $6.6 million of deferred offering costs, which are included within other noncurrent assets on the consolidated balance sheets.

Asset Retirement Obligations

The Company records the estimated fair value of obligations associated with the retirement of tangible, long-lived assets in the period in which they are incurred. When a liability is initially recorded, the Company capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value, and the capitalized cost is depleted over the useful life of the related asset.

Revisions to estimated asset retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss. The Company's asset retirement obligation relates to the plugging, dismantling, removal, site reclamation, and similar activities of its natural gas properties and midstream assets.

Asset retirement obligations are estimated at the present value of expected future net cash flows and are discounted using the Company's credit adjusted risk free rate. The Company uses unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to: costs of labor, costs of materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and discount rate. Due to the subjectivity of assumptions and the relative long lives of the Company's leases, the costs to ultimately retire the Company’s obligations may vary significantly from prior estimates. Assumptions used in determining estimates are reviewed annually.

Leases

The Company recognizes a right-of-use (“ROU”) asset and corresponding lease liability on the consolidated balance sheets for all leases. The Company determines if an arrangement is a lease at inception of the arrangement and if such lease will be classified as an operating lease or a finance lease. As of December 31, 2022 and 2021, all of the Company’s leases are accounted for as operating leases. The Company makes use of the practical expedient that permits combining lease and non-lease components.

ROU assets represent the Company’s right to use an underlying asset for the lease term and lease liabilities represent the Company’s obligation to make lease payments arising from the leases. ROU assets and lease liabilities are recognized at the lease commencement date based on the present value of minimum lease payments over the lease term. Most leases do not provide an implicit interest rate; therefore, the Company uses its incremental borrowing rate based on the information available at the inception date to determine the present value of the lease payments. Lease terms include options to extend the lease when it is reasonably certain that the Company will exercise that option. Lease cost for lease payments is recognized on a straight-line basis over the lease term. Certain leases have payment terms that vary based on the usage of the underlying assets.

Revenue Recognition

The Company recognizes revenue for the transfer of goods or services equal to the amount of consideration that it expects to be entitled to receive for those goods or services. The Company derives the majority of revenues from natural gas, NGL, and oil sales contracts. The contracts specify each party’s rights regarding the goods or services to be transferred and contain commercial substance as they impact the Company’s consolidated financial statements. A high percentage of associated receivables balance is current, and the Company has not historically entered into contracts with counterparties that pose a credit risk without requiring adequate economic protection to ensure collection. The Company determines revenue recognition through the following five step model:

- Identification of the contract(s) with a customer
- Identification of the performance obligation(s) in the contract
- Determination of the transaction price
- Allocation of the transaction price to the performance obligation(s) in the contract
- Recognition of revenue when or as performance obligation(s) are satisfied

Natural Gas, NGLs, and Oil Sales

Sales of natural gas, NGLs, and oil are recognized when the Company satisfies a performance obligation by transferring control of its product to its customers. Such sales amounts are based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement, which is variable based on commodity pricing. The Company estimates its sales volumes based on company-measured volume readings. Natural gas, NGL, and oil sales are adjusted in subsequent periods based on data received from the Company’s purchasers with the associated payment that reflects actual volumes and prices received. The data and payment are typically received by the Company within two months of transfer of control to the purchaser. Historically, the difference between estimated and actual sales revenues have not been material. Under the Company’s sales contracts, the Company invoices customers after its performance obligations have been satisfied, at which point payment is considered unconditional. Until payment for the performance obligation has occurred, the Company records an accounts receivable on its consolidated balance sheets.

BKV Corporation

Notes to the Consolidated Financial Statements

Typically, the Company's natural gas, NGL, and oil sales contracts define the price as a formula based on the average market price, as specified on set dates each month, for the specific commodity during the month of delivery. Given the industry practice to invoice customers the month following the month of delivery and the Company's payment terms which are typically within two months of control transfer, no significant financing component is included within the contracts.

Under the Company's natural gas sales contracts, it delivers natural gas to the purchaser at an agreed upon delivery point for a specified index price adjusted for pricing differentials. To deliver natural gas to the agreed upon delivery point, the Company or other third parties gather, compress, process and transport the Company's natural gas. The Company maintains control of the natural gas during gathering, compression, processing, and transportation. Upon delivery of the product, the Company transfers control and recognizes revenue based on the contract price. In this scenario, the Company is the principal, and revenues are recognized on a gross basis or based on the contract price.

The Company also enters into certain contracts for gathering and transportation of natural gas, NGL and oil products to deliver the products to customers. Fees incurred prior to control transfer are considered shipping and handling costs and are classified as gathering and transportation expense. Fees incurred after control transfer are included as a reduction to the transaction price. In this scenario, the Company is the agent, and revenues are recognized on a net basis.

For the years ended December 31, 2022, 2021, and 2020, the impact of any natural gas imbalances was not significant.

Midstream Revenues

Non-operated and operated midstream revenues are recognized when services are rendered based on quantities transported and measured according to the underlying contracts. The Company records midstream revenues based on volumes transported at stated contractual rates. The Company estimates its non-operated midstream revenue volumes based on third party data with respect to its proportionate share of non-operated volumes and actual gross volumes for operated midstream revenues. Non-operated midstream revenues are adjusted in subsequent periods based on data received from the operator that reflects actual volumes, which is typically within three months.

Marketing Revenues

In conjunction with certain contracts for the sales of natural gas and NGLs, the Company recognizes its share of net profits related to marketing revenues generated from a profit sharing agreement with a marketer. The contract includes variable components of consideration that are settled upon satisfaction of performance obligations which occurs at the point which control of the natural gas or NGLs is transferred by the purchaser to a third party. Revenues are recognized based on the underlying variable consideration pricing and delivered volumes.

Other Considerations

In addition to revenues from natural gas, NGL, and oil contracts from the Company's operated assets, BKV Corp entered into joint operating agreements as a non-operator for the sale of hydrocarbons through other operators. As a non-operator, BKV Corp recognizes revenue based on the actual (known) consideration that is obtained from the operator because BKV Corp does not have visibility into the terms of the sale. Consequently, non-operated revenue is recorded when the data is available.

The recognition of gains or losses on derivative instruments is not considered revenue from contracts with customers. The Company may use financial contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales or in limited cases may use them for contracts the Company intends to physically settle but that do not meet all of the criteria to be treated as normal sales.

BKV Corporation

Notes to the Consolidated Financial Statements

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that have a contract term greater than one year, the Company utilized the practical expedient, which does not require the disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's product sales contracts, 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. For the Company's product sales that have a contract term of one year or less, the Company utilized the practical expedient, which does not require the 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.

Contract Costs

Costs to obtain a contract are generally immaterial but the Company has elected the practical expedient to expense these costs as incurred if the duration of the contract is one year or less.

Please refer to *Note 10 — Revenue from Contracts with Customers* for additional disclosure.

Lease Operating and Workover Expense

Lease operating expenses represent certain field employees' salaries, salt water disposal, repairs and maintenance, and other standard operating expenses. Lease operating expenses are expensed as incurred.

Workover expenses include those costs incurred to perform more substantial maintenance or remedial treatments on a well to enhance production. These costs are also expensed as incurred.

Derivative Financial Instruments

The Company enters into commodity derivative instruments to reduce the effect of price volatility on a portion of the Company's future natural gas and NGL production. These activities may prevent the Company from realizing the full benefits of price increases above the levels of the derivative instruments on a portion of its future natural gas and NGL production. The commodity derivative instruments are measured and recorded at fair value and included in the consolidated balance sheets. Such fair values are calculated based on the market approach, which uses industry standard models, assumptions, and inputs. These assumptions and inputs are substantially observable in active markets throughout the full term of the instruments and include market price curves, contract terms and prices, credit risk adjustments, implied market volatility, and discount factors. The Company does not hold or issue derivative financial instruments for trading purposes. In addition, the Company has not designated any of its derivative contracts as fair value or cash flow hedges. As such, hedge accounting does not apply and any unsettled net gains and losses, or changes in the fair values of the derivative instruments, are included within derivative gains (losses), net in the consolidated statements of operations. The Company's cash flows are only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in the Company's consolidated statements of cash flows.

Credit risk is defined as the risk of a counterparty to a contract failing to perform or pay the amounts due. The Company is exposed to credit risks in its operating and financing activities. The Company's maximum exposure to credit risk is generally limited to the aggregate fair value of the outstanding contracts in an unrealized gain position offset by any collateral posted with the counterparty. The Company's counterparties are primarily with commercial banks and financial service institutions with high credit quality and are subject to master netting agreements; therefore, the risk of nonperformance by the counterparties is low. Accordingly, adjustments for counterparty credit risk are immaterial.

BKV Corporation

Notes to the Consolidated Financial Statements

Accounts Receivable and Allowance for Expected Credit Losses

The Company's receivables consist mainly of trade receivables from contracts with customers from commodity sales. Accounts receivable from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. The majority of these receivables have payment terms of 60 days or less from when control is transferred. The Company also has joint interest billings due from owners on properties the Company operates. For receivables due from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. From an evaluation of the Company's existing credit portfolio, historical credit losses have not been material to the Company and are expected to remain so in the future assuming no substantial changes to the business or creditworthiness of BKV Corp's business partners.

Fair Value of Financial Instruments

Fair value, as defined by the relevant accounting standards, represents the exchange price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The Company determines the fair values of its assets and liabilities that are recognized or disclosed at fair value in accordance with the hierarchy described below:

Level 1 — Quoted and unadjusted prices in active markets for identical assets or liabilities.

Level 2 — Observable inputs other than Level 1 prices such as: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; or (iii) valuations based on pricing models where significant inputs (e.g., interest rates, yield curves, etc.) are observable for the assets or liabilities, are derived principally from observable market data, or can be corroborated by observable market data.

Level 3 — Unobservable inputs, including valuations based on pricing models where significant inputs are not observable and not corroborated by market data. Unobservable inputs are used to the extent that observable inputs are not available and reflect the Company's own assumptions about the assumptions market participants would use in pricing the assets or liabilities. Unobservable inputs are based on the best information available under circumstances which might include the Company's own data.

Financial assets and liabilities 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 fair value measurement requires judgment and may affect the fair value of the assets and liabilities and their placement within fair value hierarchy levels.

Fair values are estimated for the majority of the Company's financial instruments. Estimations of fair value, which are based on principles such as discounting future cash flows to present value, must be weighted by the fact that the value of a financial instrument at a given time may be influenced by the market environment (particularly liquidity) and that subsequent changes in interest rates and exchange rates are not taken into account. The carrying amounts for the Company's financial instruments included in current assets and current liabilities approximates fair value due to the short-term maturities of these instruments. In addition, as of December 31, 2022, the carrying value of the Company's long-term debt approximated the fair value as the applicable interest rates are variable and reflective of current market rates.

The valuation techniques that may be used to measure fair value include a market approach, an income approach, and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost). The Company primarily applies the market and income approach for recurring fair value measurements and endeavor to utilize the best available information.

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the net assets acquired. Impairment may occur if the reporting unit's carrying value exceeds its fair value. The Company has one identifiable operating segment, which represents the Company's reporting unit where goodwill is tested. The Company performs an impairment test for goodwill at least annually or when events and circumstances indicate the carrying value may not be recoverable. In performing the required impairment tests, the Company has the option to first assess qualitative factors to determine if it is necessary to perform a quantitative assessment for goodwill impairment. If the qualitative assessment concludes that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying value, a quantitative assessment is performed. The Company's quantitative assessment utilizes present value (discounted cash flow) methods to determine the fair value of the reporting units with goodwill. Determining fair value using discounted cash flows requires considerable judgment and is sensitive to changes in underlying assumptions and market factors. Key assumptions relate to revenue growth, projected operating income growth, terminal values, and discount rates. If current expectations of future growth rates and margins are not met, or if market factors outside of the Company's control, such as factors impacting the applicable discount rate, or economic or political conditions in key markets change significantly, then goodwill of the reporting unit may be impaired. Management determined there were no circumstances indicating the carrying value of goodwill may not be recoverable during the years ended December 31, 2022, 2021, and 2020. Therefore, there have been no impairments recorded related to goodwill as the results of the annual quantitative impairment test indicated the fair value of the assets of the reporting unit to be greater than the carrying value during the years ended December 31, 2022, 2021, and 2020.

Equity-Based Compensation

The Company recognizes compensation cost related to equity-based awards in its consolidated financial statements on a straight-line basis based on estimated grant date fair value over the applicable vesting or service period. Equity-based compensation awards which ultimately settle in cash are accounted for as liabilities, and awards which are contingently settled in cash or shares of the Company's common stock are accounted for as mezzanine equity. Mezzanine equity classified awards which are considered probable of becoming redeemable are carried on the consolidated balance sheets at the greater of redemption value or initial carrying value. Changes in the redemption value of the awards result in a transfer from stockholders' equity to mezzanine equity on the consolidated balance sheets of the Company.

The Company is authorized to grant equity-based compensation in the form of restricted stock units which include service conditions, and performance-based restricted stock units, which include service conditions, market performance conditions, and non-market performance conditions. The grant date fair value is determined based on the components of the award and utilize the estimated fair market value of common stock on the grant date, Monte Carlo simulations, and the estimated fair market value of common stock on the grant date coupled with probability assessments relative to the satisfaction of non-market performance conditions.

Forfeitures are estimated and recognized over the applicable vesting or service period and are re-evaluated at the end of each reporting period. The Company's equity-based compensation is discussed further in *Note 12 — Equity-Based Compensation*.

Treasury Stock

The Company recognizes purchases of its own stock as a reduction to stockholders' equity or mezzanine equity in the consolidated balance sheets using the cost method. Shares are held until authorized for redistribution by the Company's Board of Directors.

BKV Corporation

Notes to the Consolidated Financial Statements

Equity Method Investments

The Company applies the equity method of accounting to its investments over which it does not have the power to direct the activities that most significantly impact the investment's economic performance. The Company's judgment regarding the level of influence over its equity method investments includes considering key factors such as the Company's ownership interest, representation on the investee's board of directors (the "JV Board"), and participation in the policy-making decisions of equity method investee. The carrying value of the Company's equity method investments is recorded in investment in joint venture on the consolidated balance sheets. The Company's pro-rata share of earnings in equity method investments is recorded in earnings from equity affiliates in the consolidated statements of operations.

The Company evaluates its investment in the equity method investee for impairment whenever events or changes in circumstances indicate that the carrying value of its investment may have experienced an "other-than-temporary" decline in value. If such conditions exist, the Company compares the estimated fair value of the investment to its carrying value to determine if an impairment is indicated. If impairment is indicated, the Company then determines whether the impairment is "other-than-temporary" based on its assessment of all relevant factors, including consideration of the Company's intent and ability to retain its investment.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share for each period is calculated by dividing net income (loss) available to common shareholders by the basic weighted average number of shares outstanding during the period. Diluted net income (loss) per common share is calculated by dividing net income (loss) available to common stockholders of the Company by the diluted weighted average number of common shares outstanding for the respective period. Diluted weighted average number of common shares outstanding and the dilutive effect of potential common shares is calculated using the treasury method for restricted stock units ("RSUs") and the if-converted method for preferred stock. The Company includes potential shares of common stock for PRSUs in the calculation of diluted weighted average shares outstanding based on the number of common shares that would be issuable if the end of the reporting period was also the end of the performance period. During periods in which the Company incurred a net loss, diluted weighted average common shares outstanding were equal to basic weighted average of common shares outstanding because the effects of all potential common shares was anti-dilutive.

Business Segment Information

The Company is organized and managed and identified as one operating segment and one reportable segment. The Company measures financial performance on a consolidated basis with all operating revenues and income from operations generated in, and all assets based in the United States.

Recently Issued and Adopted Accounting Standards

As of December 31, 2022 and through the date the consolidated financial statements were available for issuance (see *Note 19 — Subsequent Events*), no Accounting Standard Updates issued by the Financial Accounting Standards Board ("FASB") have been issued that are applicable to the Company and would have a material effect on the Company's consolidated financial statements and related disclosures.

Note 3 — Acquisitions and Other Related Activity

Exxon Barnett Acquisition

On May 18, 2022, the Company entered into an agreement to acquire certain operated and non-operated interests in proved reserves and certain midstream support assets (the "Purchase and Sale Agreement") in the Barnett formation (the "2022 Barnett Assets") from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation (collectively, "Seller"), for $750.0 million (subject to working capital and other adjustments) and additional contingent payments totaling $50.0 million, if certain pricing thresholds are met in future periods (the "Exxon Barnett Acquisition"). The Company paid a deposit of $75.0 million to the Seller in conjunction with entering into the Purchase and Sale Agreement. The Company closed the transaction on June 30, 2022; the adjusted purchase price, excluding contingent consideration, was $619.4 million, which included the $75.0 million deposit. As of the acquisition date, the fair value of the additional contingent payments was $17.2 million. See *Note 6 — Fair Value Measurements* and *Note 16 — Commitments and Contingencies* for discussion of the fair market value valuation methodology applied to the contingent consideration at the acquisition date and details of the contingent consideration, respectively. The Company funded the cash portion of the consideration with the proceeds from its $570.0 million term loan and the proceeds from the $75.0 million loan from BNAC. Refer to *Note 4 — Debt* and *Note 9 — Related Parties*, respectively, for further information on these loans.

The Exxon Barnett Acquisition was accounted for as a business combination; therefore, the assets acquired and liabilities assumed were recorded based on the respective estimated acquisition date fair values with information available at the time, and the residual difference between the net assets and the purchase price was recorded as a bargain purchase gain in the consolidated statements of operations. A combination of discounted cash flow models and market data was used by a third party specialist, under the direct supervision of management, in determining the fair value of the natural gas properties and midstream assets. Significant inputs into the calculation included future commodity prices, estimated volumes of natural gas, NGL, and oil reserves, expectations for the timing and amount of future development and operating costs, future plugging and abandonment costs, and a risk adjusted discount rate. The Company's assessment of the fair market value of the assets acquired and liabilities assumed is preliminary and subject to change as additional information is obtained by management. Through December 31, 2022, there have been immaterial adjustments made to the purchase price allocation. The Company expects to complete the purchase accounting, including the fair market value assessment, during the twelve month period following the date of the acquisition. The Exxon Barnett Acquisition resulted in a bargain purchase gain, which was primarily caused by the increase in commodity pricing from the date the acquisition was originally negotiated through the closing date. The bargain purchase gain of $170.9 million was recognized net of related income tax expense of $50.6 million, and is included as such on the Company's consolidated statements of operations. The Exxon Barnett Acquisition was made to support the strategic growth of the Company and to achieve operational synergies with pre-existing assets in the Barnett formation. During the year ended December 31, 2022, the Company incurred $5.0 million of acquisition costs, which are included within general and administrative expense on the consolidated statements of operations. The results of operations for the assets acquired in the Exxon Barnett Acquisition since closing on June 30, 2022 are included in the Company's consolidated statements of operations for the year ended December 31, 2022 and include $225.1 million of total revenue and $130.6 million of income from operations.

BKV Corporation

Notes to the Consolidated Financial Statements

The estimated purchase price consideration and fair value of assets acquired and liabilities assumed are as follows (in thousands):

Cash	$ 619,437
Contingent consideration	17,150
Total consideration	$ 636,587
Assets acquired and liabilities assumed:	
Inventory	$ 150
Natural gas properties – developed	657,935
Midstream assets	260,844
Other property and equipment	8,856
Property taxes	(6,296)
Deferred tax liability	(50,569)
Revenues payable	(16,612)
Asset retirement obligations	(46,867)
Total identifiable net assets	$ 807,441
Bargain purchase gain	$(170,853)

Pro Forma Information. The following pro forma financial information represents a summary of the historical consolidated results of operations for the years ended December 31, 2022 and 2021, giving effect to the Exxon Barnett Acquisition as if it had been completed on January 1, 2021. The pro forma financial information is provided for illustrative purposes only and is not intended to represent what the Company's financial position or results of operations would have been had the Exxon Barnett Acquisition occurred on the assumed date, nor does it purport to project the future operating results or the financial position of the Company following the Exxon Barnett Acquisition.

The information below reflects certain nonrecurring and recurring pro forma adjustments that were directly related to the business combination based on available information and certain assumptions that the Company believes are reasonable, including: (i) the increase in depletion and amortization reflecting the relative fair values and production volumes attributable to the Seller's natural gas properties and the revision to the depletion rate reflecting the reserve volumes acquired, (ii) the increase in depreciation expense reflecting the relative fair values attributable to the Seller's midstream assets and revision of useful lives reflecting the Company's estimate thereof, (iii) adjustments to interest expense as a result of the Company's indebtedness incurred to fund the purchase of the 2022 Barnett Assets further described in *Note 4 — Debt* and *Note 9 — Related Parties* for the $570.0 million term loan and $75.0 million related party note, respectively, (iv) increase in accretion expense reflective of the fair market value of asset retirement obligations, (v) increase of general and administrative expense during the year ended December 31, 2021 for transition services provided by the Seller upon acquisition, and a corresponding decrease of general and administrative expenses for the year ended December 31, 2022 for the actual transition service expense incurred by the Company, and (vi) the estimated tax impacts of the pro forma adjustments.

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Total revenues and other operating income	$1,253,623	$ 820,173
Net income (loss) attributable to BKV Corporation	$ 476,567	$(113,181)

Devon Barnett Acquisition

On December 17, 2019, the Company entered into a Purchase and Sale Agreement ("PSA"), which was subsequently amended, to acquire certain operated and non-operated interests in proved reserves and related

BKV Corporation

Notes to the Consolidated Financial Statements

upstream assets in the Barnett formation from Devon Energy Corporation for $570.0 million, subject to certain closing adjustments (the “Devon Barnett Acquisition”). The PSA included contingent payments totaling $260.0 million if certain commodity price thresholds are met during a four year period commencing January 1, 2021. The transaction closed on October 1, 2020. The acquisition was made to support the strategic growth of the Company.

The Company paid $70.0 million into escrow in December 2019 and an additional $100.0 million in April 2020 for a total deposit of $170.0 million. At closing the Company paid an additional $319.8 million. As of the acquisition date, the fair value of the additional contingent payments was $19.7 million. See *Note 6 — Fair Value Measurements* and *Note 16 — Commitments and Contingencies* for discussion of the fair market value valuation methodology applied to the contingent consideration at the acquisition date and related details as of December 31, 2022 and 2021.

The acquisition qualified as an asset acquisition as the fair value of substantially all the assets acquired were concentrated in a group of similar assets. Transaction costs incurred to acquire the assets, which amounted to $11.9 million, were capitalized and included in the cost basis of the acquired assets. Asset retirement liabilities were estimated to be $120.6 million as of the acquisition date.

The consideration was allocated to the assets acquired and liabilities assumed as follows:

(in thousands)	
Assets acquired	
Developed properties	$ 624,914
Other property and equipment	14,264
Inventory	2,784
Liabilities assumed	
Contingencies and contingent payments	(19,700)
Asset retirement obligations	(120,550)
Total	$ 501,712

Corporatization Event

Prior to May 1, 2020, BKV O&G, a limited partnership registered with the state of Delaware, was the sole investor in BKV Chaffee Corners, LLC, BKV Chelsea LLC, BKV Operating LLC, and BKV Barnett, LLC. Together, these consolidated entities were referred to as the “Limited Partnership.” The Limited Partnership’s general partner was Kalnin Capital Partners LP (the “General Partner”), and the Limited Partnership was managed by a related party of the General Partner, KV (the “Investment Manager”).

On May 1, 2020, the Limited Partnership’s limited partner, an international investor, and the General Partner agreed to restructure the Limited Partnership and incorporate the BKV Corp entity. As there was no change in control, the assets and liabilities continued to be recorded at their carrying amounts with no adjustment to fair value and the results of operations for these entities from the beginning of the year (January 1, 2020) are included in the consolidated statements of operations for the year ended December 31, 2020. This transaction also resulted in the measurement and recognition of minority ownership puttable common stock shares valued at $22.3 million which is further described in *Note 6 — Fair Value Measurements* and *Note 13 — Stockholders’ Equity and Mezzanine Equity*.

The Investment Manager was also merged into the new corporate structure through a business combination on May 1, 2020. Consideration of $20.0 million in the form of two million shares of common stock of the Company was paid for the acquisition of KV, in exchange for full ownership of KV, resulting in the recognition of $18.4 million of goodwill which is reflected on the consolidated balance sheets. The business combination occurred to retain operational expertise of KV, the primary factor for the recognized

BKV Corporation

Notes to the Consolidated Financial Statements

goodwill. The shares issued for the acquisition of KV were recorded as minority ownership puttable shares with a value of $20.0 million, which is reflected in the mezzanine equity section of the consolidated balance sheets and is described further in *Note 6 — Fair Value Measurements* and *Note 13 — Stockholders' Equity and Mezzanine Equity*. The transaction costs associated with the acquisition were not material due to the nature of the business combination.

The fair value of assets acquired and liabilities assumed are as follows:

(in thousands)	
Total consideration	$20,000
Assets acquired and liabilities assumed:	
Cash	$ 311
Accounts receivable	526
Other assets	753
Prepaid expenses	383
Other fixed assets	2,445
ROU assets	3,980
Accounts payable and accrued expenses	(1,488)
Lease liabilities	(5,327)
Total identifiable net assets	$ 1,583
Goodwill	$18,417

The accompanying consolidated statements of operations includes activity of KV for the period beginning May 1, 2020 through December 31, 2020. KV does not independently generate revenues; therefore, there are no revenues and other operating income, or earnings (losses) included in the Company's consolidated statements of operations from the acquisition date of May 1, 2020 to December 31, 2020 directly attributable to KV.

Note 4 — Debt

On December 22, 2021, the Company entered into an agreement with Oversea-Chinese Banking Corporation Limited (the "Bank"), which agreement provides for a revolving credit facility ("Facility I") with a limit of $55.0 million. Of the $55.0 million, a maximum of $25.0 million can be used for letters of credit, and in the absence of outstanding letters of credit, the full $55.0 million is available for cash draw downs. Facility I is not secured. Advances on Facility I are required to be repaid upon the earlier of 60 days after the date of the advance, or upon the receipt of a written demand notice from the Bank. Advances from Facility I must be greater than $1.0 million. Interest on any outstanding advances is payable monthly using the Secured Overnight Financing Rate ("SOFR") plus a credit spread of 0.11% and an interest rate margin of 2.0%. As of December 31, 2022 and 2021, the outstanding balance of Facility I was $45.0 million and zero, respectively. As of December 31, 2022, the interest rate on Facility I was 6.43%. The outstanding balance as of December 31, 2022 was paid on February 15, 2023, including the accrued interest. On March 14, 2023, the Company drew down $35.0 million on Facility I, which is due on April 14, 2023.

On March 16, 2022, the Company entered into an agreement with Standard Chartered Bank, which agreement provides for revolving term loans and letters of credit ("Facility II") with a limit of $25.0 million. Of the $25.0 million, $15.0 million is available for cash draw downs, and in the absence of outstanding cash draw downs, the full $25.0 million is available for letters of credit. Facility II is an unsecured facility committed through August 31, 2024. Interest is agreed upon at the time of each cash draw down. Cash draw downs, plus all applicable interest are payable at one, three, six, or twelve months from the date of the advance. As of December 31, 2022, Facility II had two outstanding letters of credit amounting to $13.9 million and no outstanding cash draw downs. On February 7, 2023, the Company and Standard Chartered Bank agreed to increase the limit of Facility II from $25.0 million to $50.0 million. Of the $50.0 million, $35.0 million is available for cash draw downs, and in the absence of outstanding cash draw downs, the full $50.0 million is available for letters of credit. On February 16, 2023, the Company drew down $15.0 million on Facility II, which is due on April 17, 2023. On April 13, 2023, the date the consolidated financial statements were available to be issued, the outstanding letters of credit on Facility II amounted to $19.0 million, of which $3.5 million was issued on behalf of BKV-BPP Retail, LLC. See *Note 9 — Related Parties* for further information.

On June 16, 2022, the Company entered into an agreement with a syndicate of lenders (the “Lenders”) and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent, whereby the Company can borrow up to $600.0 million in the aggregate, in the form of multiple term loans during the period commencing with the effective date and ending six months thereafter (the “Term Loan Credit Agreement”). The term loans under the Term Loan Credit Agreement must be equal to or greater than $5.0 million; amounts repaid by the Company in respect to the term loans may not be re-borrowed under the Term Loan Credit Agreement. Once drawn, the term loans are required to be repaid annually in five equal installments; installment payments are due on each anniversary of the original draw for the respective term loan. The term loans are not secured. On June 30, 2022, the Company drew a term loan of $570.0 million to fund the Exxon Barnett Acquisition. Interest is payable semi-annually in June and December using SOFR plus a credit spread of 0.10% and an interest rate margin of 4.75%. As of December 31, 2022, the interest rate of on this outstanding balance was 9.57%. The proceeds of the term loans must be used to finance the Exxon Barnett Acquisition. See *Note 3 — Acquisitions and Other Related Activity.* The Company paid debt issuance costs of $6.6 million, which was recorded in current portion of long-term debt, net and long-term debt, net in the consolidated balance sheets. As of December 31, 2022 $6.0 million remained unamortized.

On August 24, 2022, the Company entered into an agreement with Bangkok Bank Public Company Limited (New York Branch), which agreement provides for a revolving credit facility (“Facility III”) with a limit of $100.0 million. Facility III is an unsecured facility committed through September 30, 2027. Cash draw downs and all applicable interest is payable at one, three, or six months from the date of the advance (“one-month draw,” “three-month draw,” and “six-month draw,” respectively) using SOFR plus a credit spread of 0.10% and an interest rate margin of 4.75%. The interest period is determined by the Company at the time of the advance. As of December 31, 2022, the Company had $45.0 million outstanding under Facility III which consisted of a six month draw outstanding, with an interest rate at 8.38%. The Company paid debt issuance costs of $1.1 million, which was recorded in other current and noncurrent assets in the consolidated balance sheets. As of December 31, 2022, $1.0 million remained unamortized. On March 14, 2023, the Company repaid the outstanding balance of $45.0 million, including accrued interest.

As of December 31, 2022, the weighted average interest rate on the Company’s short-term borrowings of $204.0 million was 8.61%.

The Term Loan Credit Agreement and Facility III require the Company to maintain certain financial covenants, including requiring the asset coverage ratio to be no less than 2.00 to 1.00, the total net leverage ratio to be no greater than 2.50 to 1.00, and the consolidated fixed charge coverage ratio to be no less than 1.30 to 1.00. Additionally, Facility III requires the Company to have an accounts receivable balance from its largest purchaser that exceeds the outstanding balance on Facility III. As of December 31, 2022, the Company was in compliance with all covenants of the Term Loan Credit Agreement and Facility III.

BKV Corporation

Notes to the Consolidated Financial Statements

The following table summarizes the debt balances:

(in thousands)	December 31, 2022
Credit facilities	
Facility I	$ 45,000
Facility II	—
Facility III	45,000
Term loan	
Current portion of Term Loan Credit Agreement	114,000
Current portion of unamortized debt issuance costs	(1,999)
Total current debt, net	202,001
Term Loan Credit Agreement	456,000
Long-term portion of unamortized debt issuance costs	(3,964)
Total long-term debt, net	452,036
Total debt, net	$ 654,037

Note 5 — Natural Gas Properties & Other Property and Equipment

Accumulated depreciation, depletion, and amortization for developed natural gas properties as of December 31, 2022 and 2021 was $363.8 million and $267.3 million, respectively. Depreciation, depletion, and amortization expense for developed gas properties for the years ended years ended December 31, 2022, 2021, and 2020 was $96.5 million, $78.1 million, and $79.8 million, respectively.

Midstream assets consisted of the following:

(in thousands)	December 31, 2022	December 31, 2021
Compressor station	$ 37,130	$ 6,831
Meter station	654	654
Pipelines	279,325	47,878
Total	317,109	55,363
Accumulated depreciation	(11,951)	(7,417)
Midstream assets, net	$ 305,158	$ 47,946

Depreciation expense on midstream assets was $4.5 million, $1.3 million, and $1.3 million for the years ended December 31, 2022, 2021, and 2020, respectively.

Other property and equipment consisted of the following as of the periods indicated:

(in thousands)	December 31, 2022	December 31, 2021
Buildings	$ 16,788	$ 12,675
Furniture, fixtures, equipment, and vehicles	14,368	6,555
Computer software	4,844	4,715
Leasehold improvements	1,627	1,571
Land	3,090	3,090
Construction in process	9,845	—
Total	$ 50,562	$ 28,606
Accumulated depreciation	(10,697)	(6,482)
Other property and equipment, net	$ 39,865	$ 22,124

BKV Corporation

Notes to the Consolidated Financial Statements

Depreciation expense for other property and equipment was $4.4 million, $2.8 million, and $1.8 million for the years ended December 31, 2022, 2021, and 2020, respectively.

Note 6 — Fair Value Measurements

As the Company uses the market approach to determine the fair value of its derivative instruments, these fair values are also compared to the values given by counterparties for reasonableness. Since natural gas and NGL swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. The Company factors its own non-performance risk into the valuation of derivatives using current published credit default swap rates. As of December 31, 2022 and 2021, the impact of the non-performance risk adjustment to the Company's fair value of commodity derivative liabilities was $1.7 million and $4.2 million, respectively.

Contingent consideration, minority ownership puttable shares, equity-based compensation, and assets acquired and liabilities assumed in the Exxon Barnett Acquisition are measured at fair value using Level 3 valuation techniques. There were no transfers between fair value levels during the years ended December 31, 2022, 2021, and 2020.

The following tables set forth, by level within the fair value hierarchy, the financial assets and liabilities that were accounted for at fair value on a recurring basis:

	As of December 31, 2022		
	Fair Value Measurements Using:		
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets			
Commodity derivative assets	$ 3,467	$ —	$ 3,467
Financial liabilities			
Commodity derivative liabilities	49,484	—	49,484
Contingent consideration	—	88,051	88,051
Mezzanine equity			
Minority ownership puttable shares	—	62,712	62,712
Equity-based compensation	—	89,171	89,171

	As of December 31, 2021		
	Fair Value Measurements Using:		
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets			
Commodity derivative assets	$ 9,986	$ —	$ 9,986
Financial liabilities			
Commodity derivative liabilities	114,818	—	114,818
Contingent consideration	—	142,533	142,533
Mezzanine equity			
Minority ownership puttable shares	—	49,841	49,841
Equity-based compensation	—	34,006	34,006

The contingent consideration was generated from the Devon Barnett Acquisition and the Exxon Barnett Acquisition as further described in *Note 3 — Acquisitions and Other Related Activity.* The fair value

BKV Corporation

Notes to the Consolidated Financial Statements

of the contingent consideration as of December 31, 2022 and 2021 represents management's best estimate if a third party were paid to assume the contingency. The fair values were determined using Monte Carlo simulations, which use observable (Level 2) inputs based on forecasted monthly Henry Hub Prices and West Texas Intermediate ("WTI") prices, as applicable, and unobservable (Level 3) inputs. The Exxon Barnett Acquisition and Devon Barnett Acquisition contingencies are described further in *Note 16 — Commitments and Contingencies*.

The minority ownership puttable shares were recorded at fair value upon initial recognition in mezzanine equity on the consolidated balance sheets. The fair market value of the Company's common stock was used to determine the initial carrying value and redemption value of the minority ownership puttable shares in mezzanine equity on the consolidated balance sheets as of December 31, 2022 and 2021. The Company's common stock was valued using both observable (Level 2) and unobservable (Level 3) inputs. The minority ownership puttable shares are further described in the *Note 13 — Stockholders' Equity and Mezzanine Equity*.

Equity-based compensation is recorded at fair market value on the grant date. The underlying market condition was valued using the application of Monte Carlo simulations using both observable (Level 2) and unobservable (Level 3) inputs. The remaining components of the awards were valued based on the fair market value of the common stock of the Company, which is valued consistent with valuation methodologies described for the minority ownership puttable shares. As of December 31, 2022 and 2021, the fair market values of the Company's market condition and common stock were used to determine the redemption value or fair market value of equity-based compensation in mezzanine equity on the consolidated balance sheets. Equity-based compensation is further described in *Note 12 — Equity-Based Compensation and Note 13 — Stockholders' Equity and Mezzanine Equity.*

Quantitative data regarding the Company's Level 3 unobservable inputs are as follows:

(in thousands, except per share amounts)	Fair Value	Valuation Technique	Unobservable Input	Range or Actual
Contingent consideration, as of December 31, 2021	$142,533	Monte Carlo Simulation	Risk free rate[1]	1.0%
			Credit spread	4.0%
			Discount rate	5.0%
Market condition equity-based compensation per share, as of December 31, 2021	$ 13.77	Monte Carlo Simulation	Performance period dividends	3.0% equity capital, annually
Common stock – per share value, as of December 31, 2021[2]	$ 11.75	Enterprise value	Discount rate	7.7% – 9.5%
Market condition equity-based compensation per share, as of December 31, 2022	$ 17.77	Monte Carlo Simulation	Performance period dividends	3.0% equity capital, annually
Common stock – per share value, as of December 31, 2022[2]	$ 14.77	Enterprise value	Discount rate	10.0% – 11.0%
Contingent consideration, as of December 31, 2022	$ 88,051	Monte Carlo Simulation	Risk free rate[1]	4.8%
			Credit spread	4.8%
			Discount rate	9.6%

(1) Represents an observable input.

(2) The Company uses the midpoint of valuation results when estimating the fair value of common stock.

BKV Corporation

Notes to the Consolidated Financial Statements

The table below sets forth the changes in the Company's level 3 fair value measurements:

(in thousands)	December 31, 2022	December 31, 2021	December 31, 2020
Balance, beginning of period	$ 226,380	$ 54,853	$ —
Contingent consideration – additions through acquisitions	17,150	—	19,700
Contingent consideration – settled	(65,000)	(65,000)	—
Minority ownership puttable share activity	78	511	42,288
Grant date fair value of equity-based compensation	30,765	28,990	—
Change in fair market value *(all instruments)*	30,561	207,026	(7,135)
Balance, end of period	$ 239,934	$ 226,380	$ 54,853

Note 7 — Derivative Instruments

From time to time, the Company may utilize derivative contracts in connection with its natural gas and NGL operations to provide an economic hedge of the Company's exposure to commodity price risk associated with anticipated future natural gas and NGL production. The derivative contracts outstanding as of December 31, 2022 consisted of commodity swaps, basis swaps, and collar agreements, subject to master netting agreements with each individual counterparty. The following table presents gross commodity derivative balances prior to applying netting adjustments recorded in the consolidated balance sheets:

		As of December 31, 2022		
(in thousands)	Balance Sheet Location	Gross Amounts of Assets and Liabilities	Offset Adjustments	Net Amounts of Assets and Liabilities
Current derivative assets	Other current assets	$ 3,719	$ (1,068)	$ 2,651
Noncurrent derivative assets	Other noncurrent assets	816	—	816
Current derivative liabilities	Commodity derivative liabilities	50,552	(1,068)	49,484

		As of December 31, 2021		
(in thousands)	Balance Sheet Location	Gross Amounts of Assets and Liabilities	Offset Adjustments	Net Amounts of Assets and Liabilities
Current derivative assets	Other current assets	$ 9,986	$ —	$ 9,986
Current derivative liabilities	Commodity derivative liabilities	91,156	—	91,156
Noncurrent derivative liabilities	Commodity derivative liabilities	23,662	—	23,662

Collar, Commodity Swap, and Basis Swap Contracts

A commodity collar provides for a price floor and a price ceiling. The floating price for the collar contract is traded for a fixed price when the floating price is not between the floor and ceiling. If the floating price is between these contracted prices, no trade occurs. A commodity swap agreement is an agreement whereby a floating price based on the underlying commodity is traded for a fixed price over a specified period. Basis swaps provide a guaranteed price differential for natural gas from two different specified delivery points over a specified period. The fair value of open collar, commodity swap, and basis swap contracts reported in the consolidated balance sheets may differ from that which would be realized in the event the Company terminated its position in the respective contract.

BKV Corporation

Notes to the Consolidated Financial Statements

Derivative Contracts

The following tables set forth the derivative gains (losses), net on the consolidated statements of operations:

	Year Ended December 31,		
(in thousands)	**2022**	**2021**	**2020**
Total gain (loss) on settled derivatives	$(688,516)	$(268,686)	$10,427
Total gain (loss) on unsettled derivatives	58,815	(115,161)	10,329
Total gain (loss) on derivatives, net	$(629,701)	$(383,847)	$20,756

Settled derivative gains (losses), net for the years ended December 31, 2022, 2021, and 2020 includes losses of $(158.3) million and $(30.9) million, and gains of $2.7 million, respectively, related to monetization of certain natural gas derivatives prior to their contractual settlement dates.

As of December 31, 2022 and 2021, $101.7 million and $66.8 million, respectively, of settled derivatives were included in accounts payable and accrued liabilities on the Company's consolidated balance sheets. Of these amounts, $57.0 million and $23.2 million, respectively, related to monetizations.

Volume of Derivative Activities

As of December 31, 2022, the Company's derivative activities based on volume and contract prices, categorized by primary underlying risk and related commodity, by year, were as follows:

The following table represents natural gas commodity derivatives indexed to NYMEX Henry Hub pricing:

Instrument	MMBtu	Weighted Average Price (USD)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value as of December 31, 2022 (in thousands)
2023					
Swap	47,145,000	$ 3.90			$ (13,755)
Collars	41,250,000		$ 2.85	$ 3.75	$ (29,474)

The following table represents natural gas basis derivatives based on the applicable basis reference price listed below:

Instrument	Basis Reference Price	MMBtu	Weighted Average Basis Differential	Fair Value as of December 31, 2022 (in thousands)
2023				
Swap	Transco 85	9,000,000	$ 0.46	$ 277
Swap	TETCO M3	590,000	$ 10.68	$ 2,149
Swap	NGPL TXOK Basis	22,470,000	$ (0.47)	$ 993
2024				
Swap	NGPL TXOK Basis	12,840,000	$ (0.54)	$ 816

BKV Corporation

Notes to the Consolidated Financial Statements

The following table represents natural gas liquids commodity derivatives for contracts, by contract type, expiring throughout the year ended December 31, 2023 based on the applicable index listed below:

Instrument	Commodity Reference Price	Gallons	Weighted Average Price (USD)	Fair Value as of December 31, 2022 (in thousands)
Swap	OPIS Purity Ethane Mont Belvieu	38,325,000	$0.23	$ (1,743)
Swap	OPIS IsoButane Mont Belvieu Non-TET	3,832,500	$0.80	$ (853)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	3,832,500	$0.80	$ (698)
Swap	OPIS Pentane Mont Belvieu Non-TET	7,665,000	$1.28	$ (1,948)
Swap	OPIS Propane Mont Belvieu Non-TET	22,995,000	$0.72	$ (1,872)

Instrument	Commodity Reference Price	Gallons	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value as of December 31, 2022 (in thousands)
Collar	OPIS IsoButane Mont Belvieu Non-TET	9,198,000	$ 0.95	$ 1.09	$91

Note 8 — Asset Retirement Obligations

The Company has recognized an estimated liability for its asset retirement obligations related to the future costs of plugging, abandonment, and remediation of natural gas producing properties. The present value of the estimated asset retirement obligations has been capitalized as part of the carrying amount of the related natural gas properties. As of December 31, 2022 and 2021, the liability has been accreted to its present value and during the years ended December 31, 2022, 2021, and 2020, accretion expense of $12.8 million, $10.0 million, and $3.2 million, respectively, was recognized and included in depreciation, amortization, depletion, and accretion in the consolidated statements of operations.

The following table summarizes the activities of the Company's asset retirement obligations for the periods indicated:

	Year Ended December 31,		
(in thousands)	2022	2021	2020
Asset retirement obligations, beginning of period	$158,968	$148,826	$ 24,293
Additions through business combination	46,867	—	120,550
Liabilities incurred	303	923	772
Liabilities settled	(156)	(811)	—
Revision of estimates	(36,516)	—	—
Accretion of discount	12,834	10,030	3,211
Asset retirement obligations, end of period	182,300	158,968	148,826
Less current portion	(1,165)	—	—
Asset retirement obligations, long-term	$181,135	$158,968	$148,826

Note 9 — Related Parties

During 2020, the Company entered into a note payable with its majority shareholder BNAC which allowed for a single drawdown in the amount of $10.0 million. On July 1, 2020, BKV Corp drew down $10.0 million with interest at 5.3%. During the years ended December 31, 2021 and 2020, the Company

BKV Corporation

Notes to the Consolidated Financial Statements

recorded interest expense on this loan of $0.1 million and $0.2 million, respectively, in the consolidated statements of operations. The full balance of the loan was repaid during the year ended December 31, 2021.

On September 28, 2020, BKV Corp received $119.0 million in accordance with a separate loan agreement entered into with BNAC. Interest on the outstanding principal was 5.25% plus six-month LIBOR. During the years ended December 31, 2021 and 2020, the Company paid down $100.0 million and $19.0 million, respectively, on this loan, and recorded interest expense of $0.2 million and $1.5 million, respectively, in the consolidated statements of operations.

On October 14, 2021, the Company entered into a loan agreement with its majority shareholder, BNAC and borrowed $116.0 million thereunder. Interest on the outstanding principal was SOFR plus an interest rate margin of 5.25% and payable on a semi-annual basis. As of December 31, 2021, the Company had an interest payable of $1.4 million on this loan. On September 16, 2022, the Company repaid the $116.0 million principal, plus related interest, and terminated this loan agreement. During the years ended December 31, 2022 and 2021, the Company recognized interest expense of $5.5 million and $1.4 million, respectively.

On November 8, 2021, the Company entered into a loan agreement with BNAC and borrowed $50.0 million thereunder. Interest on the outstanding principal was LIBOR plus an interest rate margin of 5.25%. As of December 31, 2021, the Company had an interest payable of $0.4 million on this loan. On June 1, 2022, the Company repaid the principal plus related interest, and terminated this loan agreement. During the years ended December 31, 2022 and 2021, the Company recognized interest expense of $0.9 million and $0.4 million, respectively.

On December 23, 2021, the Company entered into a loan agreement with Temple Generation I LLC (the "Power Plant"), a wholly-owned subsidiary of BKV-BPP Power, LLC (see *Note 14 — Equity Method Investment* for further discussion on BKV-BPP Power, LLC). This loan agreement was subsequently amended on December 1, 2022 to allow the Power Plant to borrow up to $10.0 million from the Company ("Power Plant Loan"). Interest on the outstanding principal is at six-month SOFR plus an interest rate margin of 4.75%. The Power Plant Loan is due for renewal on or before November 30, 2023. As of December 31, 2022 and 2021, there were no borrowings made on the Power Plant Loan.

On March 10, 2022, the Company entered into a loan agreement (the "$75 Million Loan Agreement") with BNAC and borrowed $75.0 million thereunder. Interest on the outstanding principal is SOFR plus an interest rate margin of 5.25% is payable on a semi-annual basis, and as of December 31, 2022, the interest rate was 7.96%. The principal balance of $75.0 million is due on December 31, 2027, including any unpaid interest. On June 15, 2022, the Company entered into a subordination agreement with BNAC whereby the $75.0 million is subordinate to the term loans under the Company's Term Loan Credit Agreement, further discussed in *Note 4 — Debt*. Financial covenants under the $75 Million Loan Agreement are consistent with those of the Term Loan Credit Agreement as discussed in *Note 4 — Debt.* As of and for the year ended December 31, 2022, both interest payable under the $75 Million Loan Agreement and interest expense recognized was $4.3 million.

As of December 31, 2022 and 2021, the Company had payables of $5.2 million and $30.7 million, respectively, to BNAC for current tax expense included in income taxes payable to related party on the consolidated balance sheets. During these periods, these amounts due to BNAC are related to reimbursements for income tax related items. Separately, as of December 31, 2022 and 2021, the Company had a receivable from BNAC of $0.2 million and a $0.5 million, respectively, related to shared general and administrative expenses.

As of December 31, 2022 and 2021, the Company had accounts receivable from BKV-BPP Power, LLC of $0.2 million and $1.8 million, respectively. These receivable balances are related to reimbursement for certain expenses paid on behalf of BKV-BPP Power, LLC and amounts receivable under an Administration Services Agreement ("ASA") between the Company and BKV-BPP Power, LLC. See *Note 14 — Equity Method Investment* for further discussion of the ASA and the Company's equity method investments. During the years ended December 31, 2022 and 2021, the Company recognized $2.7 million and $0.2 million, respectively, of income related to the services provided under the ASA, which is included in related party and other on the consolidated statements of operations.

On February 17, 2023, the Company issued a letter of credit from Facility II on behalf of BKV-BPP Retail LLC in the amount of $3.5 million. See *Note 4 — Debt* for further information on this credit facility. BKV-BPP Retail, LLC is a wholly-owned subsidiary of BKV-BPP Power, LLC, and related party to the Company.

The Company's ultimate parent company, Banpu Public Company Limited, is also the ultimate parent of Banpu Power US Corporation ("BPP US"), the Company's partner in a joint venture which is discussed further in *Note 14 — Equity Method Investment*. As of December 31, 2021, the Company had accounts receivable from BPP US of $1.3 million related to reimbursement for expenses incurred during the formation of the joint venture. As of December 31, 2022, the Company had a negligible accounts receivable balance from BPP US.

Note 10 — Revenue from Contracts with Customers

All of the Company's revenues are generated in the states of Pennsylvania and Texas. Revenues consist of the following:

	Year Ended December 31, 2022		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 246,200	$1,064,139	$1,310,339
NGLs	—	311,542	311,542
Oil	—	11,866	11,866
Total natural gas, NGL, and oil sales	$ 246,200	$1,387,547	$1,633,747
Marketing revenues	—	11,001	11,001
Midstream revenues	5,845	6,831	12,676
Total	$ 252,045	$1,405,379	$1,657,424

	Year Ended December 31, 2021		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 131,207	$465,843	$597,050
NGLs	—	225,135	225,135
Oil	—	7,560	7,560
Total natural gas, NGL, and oil sales	$ 131,207	$698,538	$829,745
Marketing revenues	—	52,616	52,616
Midstream revenues	6,917	—	6,917
Total	$ 138,124	$751,154	$889,278

	Year Ended December 31, 2020		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 45,102	$56,656	$101,758
NGLs	—	11,952	11,952
Oil	—	1,333	1,333
Total natural gas, NGL, and oil sales	$ 45,102	$69,941	$115,043
Midstream revenues	7,458	—	7,458
Total	$ 52,560	$69,941	$122,501

BKV Corporation

Notes to the Consolidated Financial Statements

Accounts receivable from contracts with customers

As of December 31, 2022 and 2021, the Company's receivables from contracts with customers were $114.7 million and $100.4 million, respectively.

Note 11 — Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities included in current liabilities consists of the following:

(in thousands)	December 31, 2022	December 31, 2021
Accounts payable	$ 74,957	$ 32,237
Commodity derivative settlements payable	44,754	43,252
Commodity derivative monetizations payable	56,972	23,175
Oil and gas production and other taxes payable	37,530	29,871
Other accrued liabilities	58,262	38,301
Total	$ 272,475	$ 166,836

Note 12 — Equity-Based Compensation

On January 1, 2021, the BKV Corporation 2021 Long-Term Incentive Plan (the "Plan") was established (the "Initial Incentive Award Date") by the adoption of the Plan by the Board of Directors, which allows for the grant of incentive awards to employees and non-employee Directors of the Company in the form of RSUs. Each RSU represents the contingent right to receive one share of common stock of the Company. As of December 31, 2022, the maximum number of RSUs authorized to be awarded under the Plan was 14,941,176. However, of the total authorized RSUs under the Plan, only 60% may be awarded on or before December 31, 2022 without the written approval of the Board of Directors of the Company. Thereafter, no more than 80% of the total RSUs may be awarded without the written approval of the Board of Directors of the Company. For accounting purposes, management evaluated grants of incentive awards from the Plan in accordance with the FASB's Accounting Standards Codification ("ASC") 718 — *Compensation-Stock Compensation* ("ASC 718") and determined a grant date for all annual incentive awards, including those anticipated to be legally granted in the three years subsequent to the initial incentive award date because all grant date criteria had been satisfied and compensation expense and forfeitures were accounted for accordingly. Under ASC 718, as of December 31, 2022, 15,448,998 were considered to have been granted under the Plan since the Plan's inception when taking into consideration performance RSUs at the maximum performance level and time-based RSUs anticipated to be legally granted in the three years following the Initial Incentive Award Date. As of December 31, 2022, of the awards considered granted under ASC 718, since the Initial Incentive Award Date of the Plan, 1,423,941 RSUs were not considered legally granted.

RSUs are granted in the form of Performance-Based Restricted Stock Units ("PRSUs") and Time-Based Restricted Stock Units ("TRSUs"). The shares of common stock issued in settlement of the RSUs include a put right (the "Plan Put Right") available to the incentive award grant recipients (the "Participants"). If a Participant's employment is terminated due to voluntary resignation, and certain other conditions are met, a Participant is able to elect the Company to purchase the shares issued in settlement of his or her RSUs at fair market value of the Company's common stock at the time the election is made by the Participant. The Plan Put Right is only available to Participants upon the occurrence of certain events as defined in the Plan. As discussed below in *Modification of Terms*, this Plan Put Right was modified on November 5, 2021 to add a 181 day holding period following vesting of the RSUs. In addition, the Company has a purchase right (the "Call Right") which allows for the purchase of shares of common stock issued in the settlement of the RSUs from terminated Participants at fair market value on the date of the purchase, at the Company's discretion. As discussed below in *Modification of Terms*, this Call Right was modified on November 5, 2021 to add a 181 day holding period following vesting of the RSUs. These features, specifically the Plan Put Right, required the Company to treat the incentive awards as cash-settled or liability classified in the consolidated balance sheets of the Company until the Plan was modified as described below.

Under liability treatment, during the year ended December 31, 2021, the Company incurred $26.7 million of equity-based compensation expense, which is included within the consolidated statements of operations as general and administrative expense. Valuation methodologies used were consistent with those described below.

Modification of Terms

On November 5, 2021, the Board of Directors of the Company approved the First Amendment to the BKV Corporation 2021 Long-Term Incentive Plan (the "Plan Amendment"). The Plan Amendment included a provision to require all Participants of the Plan to hold vested shares of common stock issued in settlement of RSUs for a minimum of 181 days (the "Holding Period") prior to having the ability to exercise the Plan Put Right. The Plan Amendment also applied the Holding Period to the Call Right. Upon modification, the RSUs under the Plan are considered to be settled in equity, as the Holding Period is a reasonable period of time to experience the risk and rewards of an equity instrument. However, due to the existence of the Plan Put Right, the Company recognized the incentive awards within mezzanine equity on the consolidated balance sheets as of the date of Plan Amendment. The fair market value of the RSUs prior to the modification was $25.3 million. On the date of the Plan Amendment, this amount was transferred from liabilities into mezzanine equity on the consolidated balance sheets of the Company. All Participants of the plan agreed to the terms of the Plan Amendment. See *Note 13 — Stockholders' Equity and Mezzanine Equity* for additional discussion of the Company's treatment of equity-based compensation within mezzanine equity.

The Plan Amendment also established the Sell Fund Repurchase Program (the "Sell Fund"). Under the Sell Fund, Participants are able to tender for repurchase their vested shares of common stock to the Company after the required Holding Period, to the extent expressly permitted under their respective award agreements. On December 21, 2021, the Board of Directors of the Company approved the opening of the Company's first Sell Fund window, which closed on December 29, 2021. The opening of the Sell Fund window set forth requirements, which limited participants in the number of shares that can be tendered and a limitation whereby, in aggregate, the total value of shares tendered by all Participants cannot exceed $2.0 million per year. Sell Fund windows can be opened twice per year, and the Sell Fund will remain in effect until the earlier of December 31, 2023 or the initial public offering of the Company. During the year ended December 31, 2021, the Company repurchased 9,949 shares at $11.06 per share for a total of $0.1 million. There were no Sell Fund windows opened during the year ended December 31, 2022.

Performance-Based Restricted Stock Units

During the year ended December 31, 2022, the Company granted 466,200 of PRSUs under the Plan taking into consideration performance shares at the maximum performance level. PRSUs cliff vest and are subject to a vesting or performance period beginning January 1, 2021 and ending on the earlier of (i) December 31, 2023 (the "Performance Period"), (ii) the consummation of an IPO, or (iii) change in control of the Company. The table below summarizes the PRSU activity for the year ended December 31, 2022:

(in thousands, except per share amounts)	Shares	Weighted-Average Grant Date Fair Value
Unvested PRSUs as of January 1, 2022	11,589	$ 10.90
Granted[(1)]	466	$ 14.84
Forfeited[(1)]	(235)	$ 11.29
Unvested PRSUs as of December 31, 2022	11,820	$ 11.10

BKV Corporation

Notes to the Consolidated Financial Statements

(1) Granted and forfeited award amounts take into consideration performance shares at the maximum performance level.

PRSUs are eligible to be earned based on three performance conditions: (i) Annualized Total Shareholder Return ("TSR") of fully diluted common stock during the performance period, (ii) Return on Capital Employed ("ROCE") based on the average annual performance over the Performance Period, and (iii) IPO readiness which is based on the Company's capability to be listed on a public stock exchange at certain points during the Performance Period. Between 0% and 100% of the PRSUs at maximum performance level are eligible to be earned based on the Company achieving the following pre-established goals:

		Performance Conditions		
	Weight	Minimum Threshold (0%)	Target Threshold (50%)	Maximum Threshold (100%)
TSR	60%	5%	12.5%	20%
ROCE	20%	0%	7%	14%
IPO readiness (capability dates)	20%	12/31/2024	12/31/2023	12/31/2022

The TSR component of the awards is a market-based condition valued utilizing the Monte Carlo Simulation pricing model, which calculates multiple potential outcomes and establishes grant date fair value based on the most likely outcome. For the purposes of grant date fair value, the TSR component assumed a risk-free rate of 4.64% and volatility of 50% during the year ended December 31, 2022. See *Note 6 — Fair Value Measurements* for the level 3 unobservable input used in the determination of the grant date fair value of the TSR for the year ended December 31, 2022.The weighted average grant date fair value of the TSR component of PRSU awards granted during the year ended December 31, 2022 was $16.40.

ROCE and IPO readiness are considered to be non-market performance conditions. Thus, the likelihood of achievement must be reassessed at every reporting period, and compensation expense is adjusted accordingly. As of December 31, 2022, management estimates IPO readiness will be achieved at the maximum performance level or 100%, and ROCE performance to be greater than the target performance level at approximately 62%. Accordingly, adjustments were made to compensation expense during the year ended December 31, 2022 to reflect the estimated levels of achievement. In addition to the level of achievement, the adjustments take into account the per share grant date fair value of the Company's common stock. The grant date fair value of the PRSUs presented in the activity for year ended December 31, 2022 takes into account the grant date fair value for ROCE and IPO readiness, due to the non-market performance conditions being probable of achievement as of the respective modification date or grant date which establishes a grant date fair value. The weighted average grant date fair value of the ROCE and IPO readiness components of PRSU awards granted during the year ended December 31, 2022 was $13.08.

As of December 31, 2022, there was $28.0 million of unrecognized compensation expense related to the PRSU awards which will be amortized over a weighted average period of one year.

After the modification of terms, during the year ended December 31, 2021, equity-based compensation expense related to the PRSUs was $3.1 million. During the year ended December 31, 2022, equity-based compensation expense was $27.3 million. Both periods are included in general and administrative expenses in the consolidated statements of operations.

Time-Based Restricted Stock Units

During the year ended December 31, 2022, the Company granted 99,900 TRSUs under the Plan. As of December 31, 2022, of the awards considered granted under ASC 718 since the inception of the Plan, 1,423,941 TRSUs were not considered legally granted. Under the applicable provisions of the Plan, the TRSU incentive award was anticipated to be granted in the form of four annual awards. One quarter of the annual award requires no service for vesting and vests immediately upon the grant date. The remaining three quarters of the annual award vest in equal portions upon the subsequent three anniversary dates following the grant date. The remaining annual awards are anticipated to be granted on the first, second, and third anniversaries of the initial TRSU award date, subject to continued employment with the Company and Board of Director approval. Vesting for these anticipated three annual awards is expected to follow the same vesting schedule as the first annual awards based on the legal grant date. Upon an IPO of the Company, all unvested and legally granted and outstanding awards under the Plan will vest immediately. Awards accounted for as granted under ASC 718, but not legally granted at such time, will not vest and will be treated accordingly.

The following table summarizes the TRSU activity for the year ended December 31, 2022:

(in thousands, except per share amounts)	Shares	Weighted-Average Grant Date Fair Value
Unvested TRSUs as of January 1, 2022	2,328	$ 11.06
Granted(1)	100	$ 13.08
Vested	(316)	$ 11.11
Forfeited	(43)	$ 11.30
Unvested TRSUs as of December 31, 2022	2,069	$ 11.16

(1) Represents number of awards considered granted under ASC 718. Of these, 74,925 RSUs were not considered legally granted.

As of December 31, 2022, there was $19.1 million of unrecognized compensation expense related to the TRSU awards, which will be amortized over a weighted average period of 4.4 years.

After the modification of terms, during the year ended December 31, 2021, equity-based compensation expense related to the TRSUs was $0.5 million. During the year ended December 31, 2022 equity-based compensation expense was $4.6 million. Both periods are included in general and administrative expenses in the consolidated statements of operations.

Tax Impact

For the years ended December 31, 2022 and 2021, the Company recognized $6.4 million and $6.6 million, respectively, of tax benefit related to equity-based compensation.

Subsequent Activity

From December 31, 2022 and through the date the consolidated financial statements were available for issuance, of the 1,423,941 of TRSUs considered granted under ASC 718, but not legally granted during the year ended December 31, 2022, 577,998 of those awards have been legally granted since December 31, 2022, and the remaining 845,943 of those awards remain as considered to be granted under ASC 718, but not yet legally granted.

Note 13 — Stockholders' Equity and Mezzanine Equity

On May 1, 2020, as part of the Corporatization Event described in *Note 3 — Acquisitions and Other Related Activity — Corporatization Event*, the Company authorized 150,000,000 shares of common stock at $0.01 par and issued 94,700,000 of those shares in a private exchange with the partners in BKV O&G and the members of KV.

On December 15, 2020, the Company authorized an additional 150,000,000 shares of common stock and 80,000,000 shares of preferred stock, increasing the authorized shares of capital stock to 380,000,000.

BKV Corporation

Notes to the Consolidated Financial Statements

Common Shares Issued and Outstanding

During the year ended December 31, 2020, the Company issued 22,384,000 shares of common stock to investors for $223.8 million. 100,000 of these shares were issued in conjunction with the issuance of 9,900,000 shares of Series A Redeemable Preferred stock to the same investor.

As of December 31, 2022 and 2021, the Company had 117,325,797 and 117,102,214, respectively, of common shares issued and outstanding. See discussion below in the *Treasury Stock* section of this note for discussion of redemptions and purchases of the Company's own common stock during the years ended December 31, 2022 and 2021.

During the year ended December 31, 2021, the Company declared, and paid to the common stockholders, a cash dividend of $0.75 per share of common stock outstanding for a total of $88.1 million. There were no cash dividends declared or paid during the years ended December 31, 2022 and 2020.

Minority Ownership Puttable Shares — Mezzanine Equity

Of the 94,700,000 shares issued on May 1, 2020, 2,228,771 shares were issued to certain non-controlling management shareholders of BKV as a part of the Corporatization Event of BKV, and 2,000,000 shares were issued as part of the merger with KV (collectively, the "Management Shares"). As of December 31, 2022 and 2021, there were 3,953,378 of these minority shares outstanding. The Management Shares include a put and call feature which requires BKV to repurchase shares from these shareholders upon the occurrence of certain events stipulated in the Stockholders' Agreement at either $10.00 per share or the fair market value per share, depending on the type and timing of the triggering event. In addition, BKV may call and repurchase the Management Shares upon the occurrence of certain events stipulated in the Stockholders' Agreement at either $10.00 per share or the fair market value per share, depending on the type and timing of the triggering event. The Stockholders' Agreement, and these put and call features, will terminate upon completion of an IPO by the Company. Since the shares are not mandatorily redeemable, but can become redeemable at the option of the holder, the fair market value of the Management Shares upon issuance was recognized within mezzanine equity. As of December 31, 2022 and 2021, management has determined it is probable that the shares will become redeemable at the end of the three-year period and has elected to carry the shares at redemption value, or fair market value, in mezzanine equity on the consolidated balance sheets. During the years ended December 31, 2022, 2021, and 2020, the Company recognized adjustments of $11.9 million, $6.9 million, and $0.0 million, respectively, to the carrying value of the Management Shares to adjust to redemption value.

During the year ended December 31, 2021, certain shares were redeemed (see*Treasury Stock* section for share counts and redemption prices) causing the specific redeemed shares to no longer retain the previously mentioned rights. Accordingly, upon redemption the redeemed shares and associated carrying values were reclassified to permanent equity. No Management Shares were redeemed during the years ended December 31, 2022 and 2020.

Employee Stock Purchase Plan — Mezzanine Equity

The Company's Employee Stock Purchase Plan (the "ESPP") was adopted on November 1, 2021 and reserves 7,470,588 shares of common stock for purchase by eligible employees of the Company. The number of shares available is subject to adjustment based on anti-dilution provisions in the Stockholders' Agreement. The ESPP allows for certain eligible non-employees and members of the Board of Directors to purchase shares under the ESPP in addition to eligible employees of the Company. During the years ended December 31, 2022 and 2021, the Company issued 5,125 and 287,209, shares of common stock respectively, under the ESPP. The shares sold under the ESPP include a put right which allows for holders of the ESPP shares to require the Company to the purchase the shares upon the occurrence of certain events stipulated by the ESPP. The shares can also be purchased by the Company, at its discretion upon the occurrence of certain events, as stipulated in the ESPP. Because the shares are not mandatorily redeemable but can become redeemable at the option of the eligible employee, non-employee, or Directors, the fair market value of the shares of common stock sold under the ESPP is recognized within mezzanine equity upon issuance. Management has determined it is probable that the shares will become redeemable and has elected to carry the shares at redemption value, or fair value, in mezzanine equity on the consolidated balance sheets. During the years ended December 31, 2022 and 2021, the Company recognized an adjustment of $0.9 million and $0.1 million, respectively, to the carrying value of the ESPP shares.

Equity-Based Compensation — Mezzanine Equity

As discussed in *Note 12 — Equity-Based Compensation,* the Plan includes the Plan Put Right. Accordingly, management has determined it is probable the shares issued in settlement of the RSUs upon vesting will become redeemable and has elected to carry the shares at redemption value which equals fair market value. During the years ended December 31, 2022 and 2021, the Company recognized an adjustment to the pro-rata portion of the RSUs which have vested in the amounts of $24.4 million and $5.0 million, respectively. The maturities related to the redemption feature are in accordance with the vesting terms discussed in *Note 12 — Equity-Based Compensation*, taking into account the three year and 181 day holding periods. During the years ended December 31, 2022 and 2021, the Company issued 218,678 and 116,347, respectively, shares of common stock in settlement of vested incentive awards. As of December 31, 2022 and 2021, the Company has 335,025 and 116,347, respectively, shares of common stock issued in settlement of vested incentive awards outstanding, which are included in equity-based compensation within mezzanine equity on the consolidated balance sheets of the Company at redemption value of $4.9 million and $1.4 million, respectively.

Preferred Shares — Mezzanine Equity

On December 15, 2020, the Company authorized 80,000,000 shares of preferred stock at $10.00 par value. Of the shares of preferred stock authorized, 9,900,000 shares were designated as par Series A Cumulative Redeemable Preferred Stock (“Series A”) and these designated shares were issued during 2020 in a private exchange for $99.0 million. Cost associated with the issuance was $4.1 million. In conjunction with the issuance of the Series A shares, 100,000 shares of common stock were issued.

Series A shares carry quarterly cumulative dividends at a rate of 10% per annum for the first five years, 18% per annum for years 6 through 10, and 20% per annum, thereafter. The holder may only redeem the Series A shares upon the occurrence of liquidation, winding-up, dissolution, or change in control of the Company. The Company may also redeem the Series A shares, in whole or in part, at any time. Upon redemption by either party, the redemption value is at a price equal to $12.25 per share plus unpaid accumulated dividends at the time of redemption. Holders of the preferred shares do not have voting rights with respect to their preferred shares, however they are allowed certain consensual rights. The Series A shares include conversion features allowing for conversion into 7,425,000 shares of a new series of preferred stock and 34,873,941 shares of common stock. However, the shares do not become convertible until 10 years from the date of issuance. The number of conversion shares are adjusted pro-rata for any redemptions prior to conversion. Since the Series A shares can become redeemable at the option of the holder, but are not mandatorily redeemable, the Series A shares are classified as mezzanine equity. Management has determined it is probable the Company will exercise its redemption rights prior to the increase in cumulative dividends after year five; therefore, the carrying value of the shares is being accreted to redemption value over the expected five year period. For the year ended December 31, 2021, the Company recognized $3.7 million in accretion of preferred stock to redemption value within mezzanine equity on the consolidated balance sheets.

During April 2021, the Board of Directors of the Company declared a dividend payable to common stockholders which in turn required payment of the cumulative dividends on the Series A shares. During May 2021, the Company paid $10.3 million in dividends to preferred stock shareholders. The dividend payment represented cumulative dividends for the period of December 15 through December 31, 2020, and the year ended December 31, 2021. In conjunction with the dividend, as required by the Series A shareholders’ agreement, the Company redeemed 501,000 shares of outstanding preferred stock for

$6.1 million, of which $1.3 million represented a deemed dividend to Series A shareholders for required premiums paid upon redemption. The deemed dividend represents the difference between the redemption amount paid by the Company and the carrying value of the preferred stock prior to redemption and is reflected as such within the consolidated statements of stockholders' equity and mezzanine equity for the year ended December 31, 2021.

On October 8, 2021, the Company notified the holders of the remaining outstanding shares of preferred stock that their shares would be redeemed on October 18, 2021. The Company paid $115.1 million in order to redeem the remaining outstanding shares for preferred stock, of which $22.6 million represented a deemed dividend to preferred shareholders for required premiums paid upon redemption. The deemed dividend represents the difference between the redemption amount paid by the Company and the carrying value of the preferred stock prior to redemption and is reflected as such within the consolidated statements of stockholders' equity and mezzanine equity for the year ended December 31, 2021. As of December 31, 2022 and 2021, there were no outstanding shares of preferred stock.

Treasury Stock

On October 18, 2021 the Company purchased 100,000 shares of its common stock in conjunction with the redemption of the remaining outstanding shares of Series A shares on the same date. The shares were repurchased for $1.1 million at a price of $11.06 per share.

As discussed in *Note 12 — Equity-Based Compensation*, on December 31, 2021, the Company purchased 9,949 shares of its common stock for $0.1 million at a price of $11.06 per share.

During February, April, and December of 2021, the Company purchased a total of 275,393 shares of common stock from non-controlling management shareholders for $2.8 million at a price of $10.00 per share.

During the year ended December 31, 2022, the Company purchased 220 shares of its common stock for an immaterial amount at a price of $16.79 per share.

Note 14 — Equity Method Investment

On July 30, 2021, the Company completed the formation of a 50/50 joint venture named BKV-BPP Power, LLC (the "Joint Venture") with BPP US. The Joint Venture was formed for the sole purpose of purchasing and operating a power plant and other related activity. During August 2021, the Company contributed $43.0 million to the Joint Venture in the form of a deposit for the purchase of the Power Plant. On November 1, 2021 the Joint Venture completed the purchase of the Power Plant for $440.9 million. To complete the purchase on November 1, 2021, the Company contributed an additional $44.0 million, and BPP US contributed an equal additional $87.0 million. In addition to the contributions from the members of the Joint Venture, $141.0 million was provided from BPP US in the form of a term loan, and $141.0 million was provided by the Company's majority shareholder BNAC also in the form of a term loan. Both term loans mature on November 1, 2023. Of the total $282.0 million term loans provided by affiliates, $15.0 million was for the purposes of working capital.

In December 2021, the Company entered into the ASA with the Joint Venture, in which the Company provides certain services as required by the ASA, on an annual basis with options to extend. During the years ended December 31, 2022 and 2021, the Company recognized revenues of $2.7 million and $0.2 million, respectively, related to the services provided under the ASA, which is included in related party and other on the consolidated statements of operations.

The Joint Venture is independently operated and jointly owned by BKV Corp and BPP US through a Board of Directors consisting of eight members, four of which are appointed by BKV Corp. The remaining four members of the Board of Directors of the Joint Venture are appointed by BPP US. The Joint Venture was determined to be a variable interest entity due to its need for additional funding from its members. BKV

BKV Corporation

Notes to the Consolidated Financial Statements

Corp is not the primary beneficiary of the Joint Venture; while the majority of the ability to influence the significant activities of the Joint Venture is controlled by the JV Board, certain rights to influence the significant activities of the Joint Venture have been retained solely by BPP US, as defined by the Joint Venture's LLC agreement. Accordingly, the equity method of accounting is used by BKV Corp to account for its interest in the Joint Venture. BKV Corp's initial investment, including direct transaction costs, was $88.5 million, which represents the Company's maximum exposure to loss from the investment.

During the years ended December 31, 2022 and 2021, the Company recognized, based on its 50% ownership interest in the Joint Venture, earnings of $8.5 million and $0.9 million, respectively.

The tables below set forth the summarized financial information of the Joint Venture:

Balance Sheet (in thousands)	**As of December 31, 2022**	**2021**
Current assets	$ 43,688	$ 35,957
Noncurrent assets	434,455	454,333
Total assets	$478,143	$490,290
Current liabilities	$285,374	$ 24,067
Noncurrent liabilities	—	290,440
Total liabilities	285,374	314,507
Members' equity	192,769	175,783
Total liabilities and members' equity	$478,143	$490,290

Income Statement (in thousands)	**Year Ended December 31, 2022**	**2021**
Revenues	$ 290,428	$ 20,186
Variable operating expenses	177,701	13,388
Gross profit	112,727	6,798
Operating expenses	75,653	9,659
Income (loss) from operations	37,074	(2,861)
Net income	$ 16,986	$ 1,819

Note 15 — Credit and Other Risk

Each of the derivative contracts entered into by the Company with counterparties is subject to the terms of an International Swap Dealers Association master agreement ("Master Agreement"). On August 4, 2022, the Company entered into a third amendment to a Master Agreement with a certain counterparty (the "Counterparty"), which includes a cross default provision pursuant to which a default by the Company related to the covenants under the Company's Term Loan Credit Agreement, see *Note 4 — Debt*, would cause a default under the Master Agreement. Under the third amendment, the Company also agreed to terminate or novate, at its election, at least $100.0 million of its derivative contracts. On September 9, 2022, the Company terminated derivative contracts for $100.2 million with the Counterparty to satisfy this requirement. In connection with such termination, the Company made cash payments to the Counterparty of $100.2 million, all of which was paid by the end of 2022. The fair market value of derivative contracts as of December 31, 2022 under the Counterparty's Master Agreement was $35.3 million, which was included in current commodity derivative liabilities on the Company's consolidated balance sheets.

The Company is not currently aware of any exceptional event, dispute, risks, or contingent liabilities that could have a material impact on the assets and liabilities, results, financial position, or operations of the Company.

BKV Corporation

Notes to the Consolidated Financial Statements

The Company is subject to U.S. federal income tax as well as income in various state jurisdictions, and the Company's operating cash flow is sensitive to the amount of income taxes the Company must pay. In the jurisdictions in which the Company operates or previously operated, income taxes are assessed on earnings after consideration of all allowable deductions and credits. Changes in the types of earnings that are subject to income tax, the types of costs that are considered allowable deductions (such as intangible drilling costs) and the timing of such deductions, or the rates assessed on the Company's taxable earnings would all impact the Company's income taxes and resulting operating cash flow. In addition, new taxes are, from time to time, proposed and if enacted, could adversely impact the Company's financial condition and results of operations.

Substantially all of the Company's accounts receivable result from the sale of natural gas and joint interest billings. The Company sells natural gas, NGLs, and oil to fewer than five customers and bills working interest owners for costs related to development of the Company's natural gas properties. The Company does not believe that the loss of any of these customers would have a material adverse effect on the consolidated financial statements because alternative customers are readily available. As of December 31, 2022 and 2021, one purchaser accounted for more than 10% of accounts receivables.

Note 16 — Commitments and Contingencies

From time to time, the Company may be subject to various claims, title matters, and legal proceedings arising in the ordinary course of business, including environmental contamination claims, personal injury and property damage claims, claims related to joint interest billings and other matters under natural gas operating agreements, and other contractual disputes. The Company maintains general liability and other insurance to cover some of these potential liabilities. All known liabilities are fully accrued based on the Company's best estimate of the potential loss. While the outcome and impact on the Company cannot be predicted with certainty, for the periods presented in the consolidated financial statements, the Company believes that its ultimate liability, with respect to any such matters, will not have a significant impact or material adverse effect on its financial positions, results of operations, or cash flows. Results of operations and cash flows, however, could be significantly impacted in the reporting periods in which such matters are resolved.

The Company was involved in an arbitration against an operator related to the breach of various provisions of a certain agreement related to the construction and operation of a midstream gathering system. On February 18, 2022, the Company agreed to settle with the operator, and as a result, received payment of $35.0 million to settle all past disputes and agreed to a midstream gathering rate going forward. Of the $35.0 million, $18.1 million was considered collection of accounts receivable, and the remaining $16.9 million was recognized as a gain on settlement of litigation in the consolidated statements of operations for the year ended December 31, 2022.

The Company has volume commitments in the form of gathering, processing, and transportation agreements with various third parties that require delivery of 827,098,891 dekatherms of natural gas. The majority of the agreements terminate by 2026, with one agreement extending through 2036. As of December 31, 2022, the aggregate undiscounted future payments required under these contracts total $233.5 million. The Company expects to fulfill the commitments from existing productive wells. On March 27, 2023, the Company entered into an amendment to an existing transportation agreement to deliver an additional 249,200,000 dekatherms of natural gas through March 2027. The undiscounted future payments under this contract are $1.4 million in 2023, $8.8 million in 2024, $8.8 million in 2025, $8.7 million in 2026, and $2.2 million in 2027.

The Company may potentially be responsible for remitting lease related payments to certain leaseholders and has recorded a liability of approximately $5.7 million. Of the $5.7 million, $0.4 million was incurred during the year ended December 31, 2021. The Company will continue to evaluate these estimates and revise any recorded obligations and contingencies as necessary. During the year ended December 31, 2022, there

BKV Corporation

Notes to the Consolidated Financial Statements

was no change to the estimated value of $5.7 million of liabilities previously reported in the December 31, 2021 consolidated balance sheet.

As a part of the consideration paid for the Devon Barnett Acquisition (see *Note 3 — Acquisitions and Other Related Activity*), additional cash consideration will be required to be paid by the Company if certain thresholds are met for average Henry Hub natural gas and WTI crude oil prices for each of the calendar years during the period beginning January 2021 through December 31, 2024. Average Henry Hub payouts and threshold are as follows: $2.75/MMBtu $20.0 million, $3.00/MMBtu $25.0 million, $3.25/MMBtu $35.0 million, and $3.50/MMBtu $45.0 million; average WTI payouts and thresholds are as follows for these periods: $50.00/Bbl $10.0 million, $55.00/Bbl $12.5 million, $60/Bbl $15.0 million, and $65.00/Bbl $20.0 million. The maximum amount payable under the arrangement is $195.0 million, or $65.0 million per year for the years ending December 31, 2022 through 2024. Payments are due in the month following the end of the respective measurement period for which the hurdle rates are set. During the year ended December 31, 2022, the Company paid the 2021 portion of the arrangement of $65.0 million on January 18, 2022. As of December 31, 2022, the 2022 portion of the arrangement is considered to be settled resulting in a settlement of $65.0 million, which is reflected as contingent consideration payable within current liabilities on the consolidated balance sheets, and was paid on January 13, 2023. As described in *Note 6 — Fair Value Measurements*, management uses NYMEX forward pricing estimates for both Henry Hub and WTI hurdle rates and Monte Carlo simulations to determine the fair value of the contingent consideration. As of December 31, 2022 and 2021, the Company's estimate of the fair value of the unsettled contingent consideration was $72.5 million and $142.5 million, respectively. The change in the fair value of the contingent consideration, considering the settlements of $65.0 million for years ended December 31, 2022 and 2021 was a gain of $5.0 million and a loss of $194.9 million, respectively. For the year ended December 31, 2020, the change in the fair value of the unsettled contingent consideration was a gain of $7.1 million. These changes in the fair value during these periods impacted the associated liability on the consolidated balance sheets and recognition of the gain or loss was recognized in the gain (loss) on contingent consideration liabilities on the consolidated statements of operations.

In conjunction with the Exxon Barnett Acquisition (see *Note 3 — Acquisitions and Other Related Activity*), additional cash consideration will be required to be paid by the Company if certain thresholds for future Henry Hub natural gas prices are met for the years ended December 31, 2023 and 2024. Payouts and thresholds are as follows for the year ended December 31, 2023: $4.00/MMBtu $10.0 million, $4.50/MMBtu $17.5 million, and $5.00/MMBtu $25.0 million. Payouts and thresholds are as follows for the year ended December 31, 2024: $3.75/MMBtu $10.0 million, $4.25/MMBtu $17.5 million, and $4.75/MMBtu $25.0 million. Payments of the additional cash consideration are due as of January 31 of the calendar year following the applicable threshold measurement periods. The fair value of the contingent consideration as of the acquisition date of June 30, 2022 and as of December 31, 2022 was $17.2 million and $15.6 million, respectively. The change in the fair value of the contingent consideration for the year ended December 31, 2022 was $1.6 million, decreasing the associated liability on the consolidated balance sheets and the Company recognized a gain in gain (loss) on contingent consideration liabilities on the consolidated statements of operations. Refer to *Note 6 — Fair Value Measurements* for the valuation methodology and associated inputs.

On August 22, 2022, the Company entered into a management services agreement with Verde CO2 CCS, LLC ("Verde CO2") to provide general administrative and management services for carbon capture projects to BKVerde. Pursuant to the management services agreement, the Company is required to make fixed quarterly payments to Verde CO2 of $2.0 million, which payments began in August 2022 and end in February 2025. During this time period, Verde CO2 will facilitate the administration and development of carbon capture projects.

BKV Corporation

Notes to the Consolidated Financial Statements

A summary of the Company's commitments, excluding contingent consideration, as of December 31, 2022, is provided in the following table:

(in thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Term loan payments	$114,000	$114,000	$114,000	$114,000	$114,000	$ —	$570,000
Credit facilities	90,000	—	—	—	—	—	90,000
Interest payable	1,867	—	—	—	—	—	1,867
Notes payable to related party	—	—	—	—	75,000	—	75,000
Interest on related party notes	4,321	—	—	—	—	—	4,321
Verde CO2 management fees	8,000	8,000	1,333	—	—	—	17,333
Operating lease payments	1,517	1,029	972	848	804	859	6,029
Volume commitments	62,289	42,640	23,190	21,321	20,021	64,044	233,505
Total	$281,994	$165,669	$139,495	$136,169	$209,825	$ 64,903	$998,055

Note 17 — Income Taxes

The Company's income tax (expense) benefit consisted of the following:

Tax (Expense) Benefit

	Year ended December 31,		
(in thousands)	2022	2021	2020
Current tax (expense) benefit			
United States federal income tax	$ 30,165	$(29,051)	$ (1,232)
Various state income taxes	(3,752)	(3,176)	—
Total current income tax (expense) benefit	26,413	(32,227)	(1,232)
Deferred tax (expense) benefit			
United States federal income tax	(86,772)	66,362	(37,750)
Various state taxes	(2,293)	6,391	—
Total deferred income tax (expense) benefit	(89,065)	72,753	(37,750)
Income tax (expense) benefit	$(62,652)	$ 40,526	$(38,982)

BKV Corporation

Notes to the Consolidated Financial Statements

The following table reconciles the provision for income taxes using the federal statutory rate to the Company's effective tax rate:

Reconciliation of the Effective Tax Rate

(in thousands)	Year ended December 31, 2022	2021	2020
Income (loss) before income taxes	$472,794	$(174,989)	$ (4,364)
Federal statutory rate	21.0%	21.0%	21.0%
Income tax (provision) benefit based on statutory rate	$ (99,287)	$ 36,748	$ 916
(Increase) decrease in income taxes resulting from:			
State tax (expense) benefit, net of federal benefit	(9,948)	4,114	148
Change in state tax rate, net of federal effect	3,005	(227)	8,793
Deferred tax activity	—	520	(45,627)
Bargain purchase gain	38,139	—	—
Marginal well credit	6,417	—	—
Other, including tax credits	(978)	(629)	(3,212)
Income tax (expense) benefit	$ (62,652)	$ 40,526	$(38,982)

Deferred income taxes reflect the impact of temporary differences between assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. The tax effect of the temporary differences giving rise to net deferred tax assets and liabilities is as follows:

Recognized Deferred Income Tax Assets and Liabilities

(in thousands)	As of December 31, 2022	2021
Deferred tax assets		
Fair value of derivative financial instruments	$ 49,869	$ 31,318
Asset retirement obligations	41,315	36,680
Equity-based compensation	13,002	6,592
Contingent consideration	36,203	49,193
Interest expense carryforward	4,959	—
Net operating loss carryforward	4,231	—
Other	9,832	3,482
Total deferred tax asset	$ 159,411	$127,265
Deferred tax liabilities		
Property and equipment	$(215,379)	$ (87,554)
Investment in joint venture	(47,215)	(668)
Other	(947)	(3,539)
Total deferred tax liability	$(263,541)	$ (91,761)
Deferred tax asset (liability), net	$(104,130)	$ 35,504

As of December 31, 2022, the Company has a net operating loss carryforward for federal tax purposes of approximately $4.2 million, which does not expire. In addition, the Company has Section 163(j) interest expense carryforwards of $5.0 million as of December 31, 2022. Section 382 of the Internal Revenue Code

BKV Corporation

Notes to the Consolidated Financial Statements

limits the use of net operating losses, which includes Section 163(j) interest expense carryforwards and tax credit carryforwards in certain situations where changes occur in the stock ownership of a company. If the company should have an ownership change of more than 50% of the value of its capital stock, utilization of these carryforwards could be restricted. As of December 31, 2022, the Company's net operating losses and Section 163(j) interest expense carryforwards are not currently subject to the limits of Section 382.

In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the Company's temporary differences become deductible. Management considers the scheduled reversal of deferred tax assets, projected future taxable income, and tax planning strategies in making this assessment. Accordingly, as of December 31, 2022 and 2021, the Company has not recognized a valuation allowance against its deferred tax assets.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company recognizes those tax positions that it believes are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The Company has no unrecognized tax benefit balances as of December 31, 2022, 2021, and 2020. The Company is generally subject to potential federal and state examination for the tax years on and after December 31, 2020.

Note 18 — Earnings Per Share

The following is a reconciliation of the Company's basic weighted average number of common shares outstanding to the diluted weighted average number of common shares outstanding:

	Year Ended December 31,		
(in thousands)	**2022**	**2021**	**2020**
Basic weighted average common shares outstanding	117,318	116,904	105,275
Add: dilutive effect of TRSUs	702	—	—
Add: dilutive effect of PRSUs	5,960	—	—
Diluted weighted average of common shares outstanding	123,980	116,904	105,275
Weighted average number of outstanding securities excluded from the calculation of diluted loss per share			
TRSUs	—	473	—
PRSUs	—	1,423	—
Preferred shares	—	—	34,849

Note 19 — Subsequent Events

The Company has evaluated its subsequent events occurring after December 31, 2022 through April 13, 2023, which represents the date the consolidated financial statements were available to be issued. All such subsequent events are discussed with their relevant section within these notes to the consolidated financial statements. No further subsequent events have been identified.

Supplemental Oil and Gas Disclosures (unaudited)

The Company's operating natural gas properties are located solely in the United States.

Net Capitalized Costs Relating to Oil and Gas Producing Activities

The following table shows the capitalized costs of natural gas properties and the related accumulated depreciation, depletion, and amortization:

(In thousands)	As of December 31, 2022	2021
Developed properties	$2,252,681	$1,378,629
Undeveloped properties	15,511	16,835
Total capitalized costs	2,268,192	1,395,464
Less: Accumulated depreciation, depletion, and amortization	(363,832)	(267,293)
Net capitalized costs	$1,904,360	$1,128,171

Costs Incurred in Natural Gas and Oil Exploration and Development

The table below sets forth capitalized costs incurred in natural gas property acquisition, exploration, and development activities:

(thousands)	For the year ended December 31, 2022	2021	2020
Undeveloped property acquisition costs	$ 290	$ 3,569	$ 2,064
Acquisitions	431,897	2,928	624,914
Development costs	253,179	77,634	10,711
Total cost incurred	685,366	84,131	637,689
Asset retirement obligations[1]	38,337	923	772
Total costs incurred, including asset retirement obligations	$723,703	$85,054	$638,461

(1) The amount as of December 31, 2022 includes $38.0 million related to the Exxon Barnett Acquisition.

The Company's results of operations from natural gas and oil producing activities are not materially different from the amounts presented within the consolidated statements of operations due to substantially all of the Company's operating activity relating to natural gas and oil producing activities. Accordingly, no supplemental disclosure information for the results of operations from natural gas and oil producing activities is included herein.

Natural Gas, NGL, and Oil Reserve Quantities

Estimates of the Company's total proved reserves are based on studies performed by the Company's internal engineering function and services provided by Ryder Scott, the Company's independent third-party reserve engineer. As of December 31, 2022, 2021, and 2020 the Company's estimates of total proved reserves are based on reserve reports prepared by Ryder Scott. Pricing for natural gas, NGLs and oil is computed using the 12-month average index price, calculated as the unweighted arithmetic average for the first day of the month price for each month during the respective year. The process of estimating quantities of "proved" and "proved developed" and "proved undeveloped" natural gas, NGL, and oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering, and economic data. The Company's reserve reports also include estimates of asset retirement obligations for all properties for which an asset retirement obligation exists. Estimates for asset retirement obligations include all costs associated with abandonment after salvage. The data used in the Company's reserve reports may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data make these estimates generally less precise than other estimates included within the consolidated financial statements.

The following tables illustrate the changes in the Company's quantities of net proved reserves:

	Natural Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Total (MMcfe)
January 1, 2020	948,801	—	—	948,801
Revision of previous estimates	(382,366)	(21)	(3)	(382,510)
Extensions and discoveries	—	—	—	—
Purchase of minerals in place	1,515,255	109,820	755	2,178,705
Improved recoveries	—	—	—	—
Production	(96,158)	(2,565)	(29)	(111,722)
December 31, 2020	1,985,532	107,234	723	2,633,274
Revision of previous estimates	828,360	45,234	258	1,101,312
Extensions and discoveries	645,338	13,722	58	728,018
Purchase of minerals in place	19,511	—	—	19,511
Improved recoveries	152,597	8,794	9	205,415
Production	(186,055)	(9,829)	(123)	(245,767)
December 31, 2021	3,445,283	165,155	925	4,441,763
Revision of previous estimates	(119,200)	(388)	43	(121,270)
Extensions and discoveries	364,492	30,038	786	549,436
Purchase of minerals in place	1,323,059	23,406	255	1,465,025
Improved recoveries	59,621	3,477	—	80,483
Production	(217,585)	(10,187)	(140)	(279,547)
December 31, 2022	4,855,670	211,501	1,869	6,135,890
Proved developed reserves as of:				
January 1, 2021	1,893,158	107,234	723	2,540,900
December 31, 2021	2,494,925	151,433	867	3,408,725
December 31, 2022	3,798,027	170,840	1,111	4,829,733
Proved undeveloped reserves as of:				
January 1, 2021	92,374	—	—	92,374
December 31, 2021	950,358	13,722	58	1,033,038
December 31, 2022	1,057,649	40,660	758	1,306,157

	Developed	Undeveloped	Total
		(MMcfe)	
January 1, 2020	523,240	425,561	948,801
Revision of previous estimates	(49,323)	(333,187)	(382,510)
Extensions and discoveries	—	—	—
Purchase of minerals in place	2,178,705	—	2,178,705
Improved recoveries	—	—	—
Production	(111,722)	—	(111,722)
Undeveloped reserves converted to developed	—	—	—
December 31, 2020	2,540,900	92,374	2,633,274
Revision of previous estimates	855,750	245,562	1,101,312
Extensions and discoveries	15,399	712,619	728,018
Purchase of minerals in place	17,664	1,847	19,511
Improved recoveries	205,415	—	205,415
Production	(245,767)	—	(245,767)
Undeveloped reserves converted to developed	19,364	(19,364)	—
December 31, 2021	3,408,725	1,033,038	4,441,763
Revision of previous estimates	234,914	(356,184)	(121,270)
Extensions and discoveries	74,092	475,344	549,436
Purchase of minerals in place	1,237,142	227,883	1,465,025
Improved recoveries	80,483	—	80,483
Production	(279,547)	—	(279,547)
Undeveloped reserves converted to developed	73,924	(73,924)	—
December 31, 2022	4,829,733	1,306,157	6,135,890

2022 Activity

During the year ended December 31, 2022, the Company’s proved reserves increased by 1,694.1 Bcfe. The increase in proved reserves was primarily due to the acquisition of the 2022 Barnett Assets. Other factors that contributed to the increase in proved reserves during the year ended December 31, 2022 included increasing commodity pricing which improved economics, improved recoveries from application of restimulation technology to producing wells, and the addition of NGL rich locations to the drilling schedule. The Company produced 279.5 Bcfe during the year ended December 31, 2022.

Revisions of previous estimates — Consisted of upward revisions to proved developed reserves of 182.9 Bcfe as a result of higher average pricing during 2022 for natural gas, NGLs, and oil. An additional upward revision of 52.0 Bcfe was made to proved developed reserves for performance adjustments. Upward revisions were offset by downward revisions to proved undeveloped reserves of 246.0 Bcfe relating to 76.0 gross, (53.1 net) locations in the Marcellus and Barnett basins removed from the drilling schedule in exchange for locations with more favorable economics which are discussed in *2022 Activity — Extensions and discoveries*. Additional downward revisions of 67.3 Bcfe and 42.9 Bcfe were made to proved undeveloped reserves related to performance and increased development costs, respectively.

Extensions and discoveries — Primarily consisted of 389.5 Bcfe of proved undeveloped reserves for 71.0 gross (66.4 net) locations recognized as a result of the Company’s revised evaluation of properties acquired through our Devon Barnett Acquisition. These locations are more rich in NGLs than the previously recognized locations removed from the 2021 drilling schedule as discussed in *2022 Activity — Revisions of previous estimates.* Additional extensions consisted of proved undeveloped reserves of 85.8 Bcfe related to 27.0 gross (12.8 net) locations in the Marcellus and Barnett basins recognized from acreage acquired during 2021 and as a result of the revised 2022 drilling plan. Extensions related to proved developed reserves of 74.1 Bcfe consisted of 23.0 gross (13.0 net) newly drilled wells on locations previously classified as unproved.

Purchases of minerals in place— Consisted of 1,237.1 Bcfe and 227.9 Bcfe of proved developed and proved undeveloped reserves, respectively, from the Exxon Barnett Acquisition. The acquired reserves consisted of operated working interests in 2,289.0 gross (1,696.4 net) wells and 53.0 gross (48.7 net) undeveloped locations.

Improved recoveries — Consisted of 80.5 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2022.

Conversions of proved undeveloped reserves to proved developed reserves — Consisted of 73.9 Bcfe related to the completion of 19.0 gross (5.5 net) wells during the year ended December 31, 2022 on proved undeveloped locations previously classified as proved undeveloped.

In early 2023, natural gas commodity prices decreased significantly, and the Company expects this lower natural gas commodity pricing environment to continue at least into the second quarter of 2023. Due to the Company’s desire to be a prudent operator and exercise capital discipline in the lower natural gas pricing environment, in March 2023, the Company decreased its capital expenditures budget for development of natural gas properties for 2023 to $80.8 million from its original budget of $278.3 million, which was the amount applied in connection with the preparation of the estimates of the Company’s reserve report as of December 31, 2022. The Company estimates that this reduction in 2023 capital expenditures would result in a decrease of the Company’s proved reserve quantities and standardized measure of discounted future net cash flows of proved reserves as of December 31, 2022, by approximately 4.1%, and 3.8%, respectively. If the current lower natural gas commodity pricing environment extends beyond 2023, the Company will continue to maintain capital discipline and reflect corresponding capital expenditure changes in the Company’s estimated reserves as of December 31, 2023. These changes would mainly impact proved undeveloped reserve quantities and proved developed non-producing reserve quantities, which collectively represent approximately 27.9% of the Company’s total estimated proved reserves as of December 31, 2022.

2021 Activity

During the year ended December 31, 2021, the Company’s proved reserves increased by 1,808.5 Bcfe. The increase in proved reserves was primarily due to increasing commodity pricing which improved economics, and additions to the drilling schedule for both proved developed and undeveloped reserves. The Company produced 245.8 Bcfe during the year ended December 31, 2021.

Revisions of previous estimates — Primarily consisted of upward revisions to proved developed reserves, and proved undeveloped reserves of 715.9 Bcfe and 245.6 Bcfe, respectively, as a result of higher average pricing during 2021 for natural gas, NGLs, and oil. The remaining upward adjustment of 139.8 Bcfe relates to upward performance adjustments to proved developed reserves of 219.2 Bcfe offset by a downward revision to proved developed reserves of 79.4 Bcfe due to increased production costs.

Extensions and discoveries — Upon completing the evaluation of properties acquired through the Company’s Barnett Asset Acquisition, 550.1 Bcfe of proved undeveloped reserves was recognized for 123.0 gross (94.8 net) locations added to the Company’s revised drilling schedule during 2021. Additional extensions consisted of proved undeveloped reserves of 162.5 Bcfe related to 13.0 gross (9.6 net) locations in the Marcellus Basin recognized from acquired acreage and the revised 2021 drilling plan. Extensions related to proved developed reserves of 15.4 Bcfe consisted of 10.0 gross (3.0 net) newly drilled wells.

Purchases of minerals in place— Consisted of 17.7 Bcfe of proved developed reserves from the acquisition of additional working interests in 601.0 gross (14.6 net) wells and 1.8 Bcfe of proved undeveloped reserves from the acquisition of additional working interest in 18.0 gross (1.0 net) locations, each of which were in addition to the Company’s previously held working interests in wells or working interests in locations in the Barnett.

Improved recoveries — Consisted of 205.4 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2021.

Conversions of proved undeveloped reserves to proved developed reserves— Consisted of 19.4 Bcfe related to the completion of 4.0 gross (3.9 net) wells on proved undeveloped locations during the year ended December 31, 2021.

2020 Activity

During the year ended December 31, 2020, the Company's proved reserves increased by 1,684.5 Bcfe. The increase in proved reserves was due to the Barnett Asset Acquisition offset by downward revision primarily due to lower average pricing for natural gas during 2020.The Company produced 111.7 Bcfe during the year ended December 31, 2020.

Revisions of previous estimates — Proved undeveloped reserves consisted of a downward revision of 146.7 Bcfe due to a combination of performance adjustments and lower average pricing of natural gas during 2020, and a downward revision of 186.5 Bcfe which removed locations due to lower average pricing of natural gas during 2020. Proved developed reserves were adjusted downward by 49.3 Bcfe due to lower average natural gas prices and performance.

Extensions and discoveries — There were no extensions and discoveries of proved developed or proved undeveloped reserves during the year ended December 31, 2020.

Purchases of minerals in place— Consisted of 2,178.7 Bcfe of proved developed reserves from the acquisition of 4,296.0 gross wells (3,867.5 net) from the Devon Barnett Acquisition.

Standardized Measure of Discounted Future Net Cash Flows

The following information has been developed based on natural gas, NGL, and oil reserve cash flows, including production volumes from the Company's reserve reports. It can be used for some comparisons but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas Reserves ("Standardized Measure") be viewed as representative of the current value of the Company.

The following table details the Standardized Measure related to proved reserve as of the periods presented:

Future cash flows (in thousands)	As of December 31,		
	2022	2021	2020
Future cash inflows	$ 34,992,383	$15,029,839	$ 4,414,787
Future production costs	(11,967,176)	(6,840,969)	(2,954,242)
Future development costs[(1)]	(1,859,661)	(1,051,911)	(333,804)
Income tax expense	(4,572,275)	(1,501,984)	(98,882)
Future net cash flows	16,593,271	5,634,975	1,027,859
10% annual discount for estimated timing of cash flows	(9,599,669)	(3,222,086)	(517,449)
Standardized measure of discounted future net cash flows related to proved reserves	$ 6,993,602	$ 2,412,889	$ 510,410

(1) Includes abandonment costs

The following table summarizes the changes in the Standardized Measure:

(in thousands)	For the Year Ended December 31, 2022	2021	2020
Balance, beginning of period	$ 2,412,889	$ 510,410	$ 406,824
Net change in sales and transfer prices and in production (lifting) costs related to future production	4,656,150	1,768,893	(284,282)
Changes in estimated future development costs	43,101	(393,235)	114,330
Sales and transfers of natural gas, NGLs, and oil produced during the period	(1,293,492)	(522,403)	(83,783)
Net change due to extensions, discoveries, and improved recoveries	824,295	183,332	—
Purchase of minerals in place	1,649,737	19,050	513,183
Net change due to revisions in quantity estimates	(86,088)	1,266,086	(161,762)
Previously estimated development costs incurred during the period	37,784	60,406	13,540
Net change in future income taxes	(1,299,320)	(611,031)	(50,548)
Accretion of discount	322,498	56,096	40,682
Changes in timing and other	(273,952)	75,285	2,226
Total discounted cash flow as end of period	$ 6,993,602	$2,412,889	$ 510,410

Report of Independent Auditors

To the Management of XTO Energy Inc.

Opinion

We have audited the accompanying statements of revenues and direct operating expenses of the Barnett Assets of XTO Energy Inc. and Barnett Gathering, LLC (the “Company”), for the years ended December 31, 2021 and 2020, including the related notes (referred to as the “statements of revenues and direct operating expenses”).

In our opinion, the accompanying statements of revenues and direct operating expenses present fairly, in all material respects, the revenues in excess of direct operating expenses of the Company for the years ended December 31, 2021 and 2020 in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit 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 Auditors’ Responsibilities for the Audit of the Statements of Revenues and Direct Operating Expenses 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 audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of Matter

The accompanying statements of revenues and direct operating expenses were prepared in connection with XTO Energy Inc. and Barnett Gathering LLC’s divesture of the Barnett Assets and, as described in Note 1, were prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission. The statements of revenues and direct operating expenses are not intended to be a complete presentation of the financial position, results of operations or cash flows of the Barnett Assets of XTO Energy Inc. and Barnett Gathering LLC. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Statements of Revenues and Direct Operating Expenses

Management is responsible for the preparation and fair presentation of the statements of revenues and direct operating expenses 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 the statements of revenue and direct operating expenses that are free from material misstatement, whether due to fraud or error.

In preparing the statements of revenues and direct operating expenses, 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 statements of revenues and direct operating expenses are available to be issued.

Auditors’ Responsibilities for the Audit of the Statements of Revenues and Direct Operating Expenses

Our objectives are to obtain reasonable assurance about whether the statements of revenues and direct operating expenses as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditors’ 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 statements of revenues and direct operating expenses.

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 statements of revenues and direct operating expenses, 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 statements of revenues and direct operating expenses.
- 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 statements of revenue and direct operating expenses.
- 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/ PricewaterhouseCoopers LLP

Dallas, Texas
September 12, 2022

BARNETT ASSETS

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

(in U.S. Dollars)	Year Ended December 31, 2021	Year Ended December 31, 2020	Six Months Ended June 30, 2022 (Unaudited)	Six Months Ended June 30, 2021 (Unaudited)
REVENUES				
Oil and condensate, gas and NGL sales	307,980,127	183,587,740	219,232,387	117,279,977
Midstream operating revenues	6,243,524	6,400,076	3,620,836	2,788,135
Other revenues	267,540	395,570	247,704	127,602
Total Revenues	314,491,191	190,383,386	223,100,927	120,195,714
DIRECT OPERATING EXPENSES				
Lease operating expense	76,921,954	83,055,070	47,456,160	36,713,078
Overhead costs	20,826,466	20,523,594	10,720,051	10,442,276
Cost of goods sold	49,794,678	50,306,855	25,320,736	22,616,152
Production and property taxes	21,667,036	17,056,948	10,696,307	4,262,571
Total Direct Operating Expenses	169,210,134	170,942,467	94,193,254	74,034,077
REVENUES IN EXCESS OF DIRECT OPERATING EXPENSES	145,281,057	19,440,919	128,907,673	46,161,637

BARNETT ASSETS

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES
Years Ended December 31, 2021 and 2020 and Six Months Ended June 30, 2022 and 2021 (unaudited)

Note 1 — Basis of Presentation

XTO Energy Inc. and Barnett Gathering, LLC (together, the “Company”), wholly-owned subsidiaries of ExxonMobil Corporation owned oil and gas properties located in the Barnett Shale/Fort Worth Basin (the “Properties”), consisting of approximately 160,000 net acres, 2700 gross wells, and certain midstream gathering infrastructure. On May 18, 2022, the Company entered into a purchase and sale agreement with BKV North Texas, LLC and BKV Midstream, LLC (together, “BKV” or the “Buyer”), under which BKV agreed to acquire the Properties from the Company in a cash transaction for aggregate consideration of $750.0 million, subject to customary closing purchase price adjustments and certain additional contingent payments. The transaction closed on June 30, 2022.

The Statements of Revenues and Direct Operating Expenses (the “Statements”) have been derived from the historical financial records of the Company, which represent their interests in revenues and expenses associated with the Properties, and were not accounted for as a separate subsidiary or division during the periods presented. Accordingly, a complete set of financial statements required by Regulation S-X, including a balance sheet and cash flow statement, prepared under U.S. generally accepted accounting principles (“GAAP”) is not available or practicable to prepare for the Properties.

The Statements are not intended to be a complete presentation of the results of operations of the Properties as they do not include depreciation, depletion and amortization, accretion of asset retirement obligations, general and administrative expenses, interest expense, and income taxes. These costs are excluded because they are either not comparable to future operations, or they were not separately allocated to the Properties in the Company’s historical accounting records. In addition to these exclusions, the Statements may not be representative of future operations due to potential changes in the business of the Buyer.

The accompanying Statements for the six months ended June 30, 2022 and 2021 are unaudited. The unaudited interim Statements have been prepared on the same basis as the annual Statements. In the opinion of management, such unaudited interim statements reflect all adjustments necessary for fair statement of the revenues and direct operating expenses of the Properties.

Note 2 — Use of Estimates in Preparation of the Statements

The preparation of these Statements requires management to make estimates and assumptions that affect the reported amounts of revenues and direct operating expenses during the respective reporting periods. Actual results may differ from the estimates and assumptions used in the preparation of the Statements.

Note 3 — Revenue Recognition

The Company generally sells crude oil and natural gas under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions. Revenue is recognized at the amount the Company expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when the price is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days. Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

Note 4 — Direct Operating Expenses

Direct operating expenses are recognized when incurred and consist of direct operating expenses of the Properties. The direct operating expenses include lease operating expenses and deductions. Lease operating

BARNETT ASSETS

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES
Years Ended December 31, 2021 and 2020 and Six Months Ended June 30, 2022 and 2021 (unaudited)
(continued)

expenses include lifting costs, well repair expenses, facility maintenance expenses, well workover costs, and other field-related expenses. Lease operating expenses also include overhead and expenses directly associated with support personnel, support services, equipment, and facilities directly related to oil and gas production activities. Other deductions include cost of goods sold such as gathering and transportation expenses, and purchases of third party gas. Deductions also include the associated production taxes and property taxes associated with the Properties.

Note 5 — Subsequent Events

The Company has evaluated subsequent events through September 12, 2022, the date the Statements of Revenues and Direct Operating Expenses were available to be issued, and has concluded that no events need to be reported.

BARNETT ASSETS

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Estimated Quantities of Proved Oil, Natural Gas, and NGL Reserve Quantities

Estimated quantities of proved natural gas, NGL and oil reserves at December 31, 2021, and December 31, 2020 and changes in the reserves during each period for the Properties, are shown below. For the years ended December 31, 2021 and 2020 all reserves are proved developed.

These estimates have been prepared in accordance with SEC regulations regarding oil and natural gas reserve reporting using the average price during the trailing 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month.

Estimates of proved natural gas, NGL and oil reserves have been completed in accordance with professional engineering standards. The estimates of proved natural gas, NGL and oil reserves were prepared by the Buyer's petroleum engineers for the years ended December 31, 2021 and 2020. Those proved reserves estimates were calculated by adding back production (rolled back) and adjusting for pricing from a reserve report prepared by Ryder Scott Company L.P., an independent petroleum consulting firm engaged by the Buyer, as of June 30, 2022, as this method was deemed to provide the best estimates based on information available.

	Natural Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Total (MMcfe)
January 1, 2020	965,033	18,703	189	1,078,385
Revision of previous estimates[1]	(217,748)	(4,441)	(45)	(244,664)
Production	(85,388)	(1,435)	(19)	(94,112)
December 31, 2020	661,897	12,827	125	739,609
Revision of previous estimates[2]	359,153	6,807	77	400,457
Production	(74,076)	(1,283)	(18)	(81,882)
December 31, 2021	946,974	18,351	184	1,058,184

(1) The downward revisions of previous estimates of 244,664 MMcfe for the year ended December 31, 2020 were the result of lower product pricing.

(2) The upward revisions of previous estimates of 400,457 MMcfe for the year ended December 31, 2021 were the result of higher commodity prices and improved well performance.

BARNETT ASSETS

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) (continued)

Standardized Measure of Discounted Future Net Cash Flows

The Buyer prepared the following summary which sets forth the Buyer's future net cash flows relating to proved natural gas, NGL and oil reserves based on the standardized measure for the years ended December 31, 2021 and 2020. As discussed in Note 1 Basis of Preparation, the effects of federal income taxes are not included in the accompanying Statements, and similarly are not included in the standardized measure presented.

Future cash flows (in thousands)	As of December 31, 2021	2020
Future estimated revenues(1)	$ 2,724,244	$ 686,798
Future estimated production costs(2)	(1,190,931)	(508,748)
Future estimated development costs(2)	(121,966)	(122,467)
Future income tax expense(3)	(14,302)	(3,606)
Future net cash flows	1,397,045	51,977
10% annual discount for estimated timing of cash flows	(688,067)	(25,602)
Standardized measure of discounted future net cash flows related to proved reserves	$ 708,978	$ 26,375

(1) In accordance with SEC regulations regarding oil and natural gas reserve reporting, reserves were estimated using the average price during the trailing 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month.

(2) Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions.

(3) As stated above, no provisions for future federal income taxes were included; however, provisions for future obligations under the Texas gross margin tax are included.

BARNETT ASSETS

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) (continued)

The following table summarizes the changes in the Standardized Measure of discount future net cash flows:

	For the Years Ended December 31,	
(in thousands)	**2021**	**2020**
Balance, beginning of period	$ 26,375	$ 341,528
Net change in sales and transfer prices and in production (lifting) costs related to future production	574,114	(179,269)
Changes in estimated future development costs	148	(782)
Sales and transfers of natural gas, NGLs and oil produced during the period	(188,565)	(62,952)
Net change due to revisions in quantity estimates	278,939	(104,659)
Net change in future income taxes	(4,558)	2,402
Accretion of discount	2,815	34,571
Changes in timing and other	19,710	(4,464)
Total discounted cash flow as end of period	$ 708,978	$ 26,375

The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations involve significant estimates and judgments. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the prices and costs utilized in the computation of reported amounts above. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

PART II INFORMATION

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other Expenses of Issuance and Distribution.

The following table sets forth the various expenses, other than underwriting discounts and commissions, payable by us in connection with the offering of our common stock contemplated by this registration statement. All of the fees set forth below are estimates, except for the SEC registration fee, the Financial Industry Regulatory Authority, Inc. ("FINRA") filing fee and the NYSE listing fee.

SEC registration fee	$11,020
FINRA filing fee	15,500
NYSE listing fees	*
Transfer agent and registrar fees and expenses	*
Printing fees and expenses	*
Legal fees and expenses	*
Accounting fees and expenses	*
Miscellaneous	*
Total	$ *

* To be provided by amendment.

Item 14. Indemnification of Directors and Officers.

Our certificate of incorporation will provide that directors and officers will not be liable to the Company or its stockholders for monetary damages to the fullest extent permitted by the DGCL. In addition, if the DGCL is amended to authorize the further elimination or limitation of the liability of directors and officers, then the liability of a director or officer of the Company, in addition to the limitation on personal liability provided for in our certificate of incorporation, will be limited to the fullest extent permitted by the amended DGCL. Our bylaws will provide that the Company will indemnify, and advance expenses to, any officer or director to the fullest extent authorized by the DGCL.

Section 145 of the DGCL provides that a corporation may indemnify directors and officers as well as other employees and individuals against expenses, including attorneys' fees, judgments, fines and amounts paid in settlement in connection with specified actions, suits and proceedings whether civil, criminal, administrative, or investigative, other than a derivative action by or in the right of the corporation, if they acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe their conduct was unlawful. A similar standard is applicable in the case of derivative actions, except that indemnification extends only to expenses, including attorneys' fees, incurred in connection with the defense or settlement of such action and the statute requires court approval before there can be any indemnification where the person seeking indemnification has been found liable to the corporation. The statute provides that it is not exclusive of other indemnification that may be granted by a corporation's certificate of incorporation, bylaws, disinterested director vote, stockholder vote, agreement or otherwise.

Our certificate of incorporation will also contain indemnification rights for our directors and our officers. Specifically, our certificate of incorporation will provide that we shall defend, indemnify and advance expenses to our officers and directors to the fullest extent authorized by the DGCL. Further, we may maintain insurance on behalf of our officers and directors against expense, liability or loss asserted incurred by them in their capacities as officers and directors.

In addition, we intend to enter into indemnification agreements, to be effective upon the completion of this offering, with our current directors and officers containing provisions that are in some respects broader than the specific indemnification provisions contained in the DGCL. The indemnification agreements will require us, among other things, to indemnify our directors and officers against certain liabilities that may arise by reason of their status or service as directors or officers and to advance their expenses incurred as a result of any proceeding against them as to which they could be indemnified. We also intend to enter into indemnification agreements with our future directors and officers.

We intend to maintain liability insurance policies that indemnify our directors and officers against various liabilities, including certain liabilities arising under the Securities Act or the Exchange Act that may be incurred by them in their capacity as such.

The proposed form of Underwriting Agreement to be filed as Exhibit 1.1 to this registration statement provides for indemnification of our directors and officers by the underwriters against certain liabilities arising under the Securities Act or otherwise in connection with this offering.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling us pursuant to the foregoing provisions, we have been informed that in the opinion of the SEC, such indemnification is against public policy as expressed in the Securities Act and is therefore unenforceable.

Item 15. Recent Sales of Unregistered Securities.

In the three years preceding the filing of this registration statement, we have issued the following unregistered securities.

Corporatization Event

The information set forth in "*Business — Our History — The Corporatization Event*" of the prospectus is incorporated herein by reference. On May 1, 2020, as part of the Corporatization Event, the Company issued 92,700,000 shares of its common stock in exchange for a contribution by the partners of BKV O&G of all of the partnership interests in BKV O&G and 2,000,000 shares of its common stock in exchange for a contribution by the members of Kalnin Ventures of all of the membership interests in Kalnin Ventures. The foregoing issuances were made under an exemption from registration provided by Section 4(a)(2) of the Securities Act, and no underwriters were involved in these transactions.

Other Equity Issuances

On October 1, 2020, the Company issued 22,284,000 shares of its common stock to an existing investor, BNAC, for $222.8 million. The foregoing issuance was made under an exemption from registration provided by Section 4(a)(2) of the Securities Act, and no underwriters were involved in this transaction.

On December 15, 2020, the Company issued 100,000 shares of its common stock to a new investor, OCM BKV Holdings, LLC, an affiliate of Oaktree Capital Management L.P., for $1.0 million, net of associated costs. These shares were issued in connection with the issuance of 9,900,000 shares of Series A Redeemable Preferred Stock, par value $10.00 per share, of the Company (the "Series A preferred stock"), to the same investor in a private placement for $99.0 million. The foregoing issuances were made under an exemption from registration provided by Section 4(a)(2) of the Securities Act and Rule 506(b) of Regulation D promulgated thereunder, and no underwriters were involved in these transactions. The Company redeemed a portion of such shares of Series A preferred stock in May 2021 and the remainder in October 2021.

2021 Plan Issuances

From January 1, 2021 through December 31, 2021, performance restricted stock units (PRSUs) were legally granted under the 2021 Plan, which, assuming vesting at maximum payout, would result in the vesting of 12,256,502 shares of the Company's common stock, and 656,595 time restricted stock units (TRSUs) were legally granted, of which 164,112 TRSUs were vested at the time of grant and 295,731 TRSUs have since vested. From January 1, 2022 through December 31, 2022, additional PRSUs were legally granted, which, assuming vesting at maximum payout, would result in the vesting of 466,200 shares of the Company's common stock, and 645,760 TRSUs were legally granted, of which 306,299 TRSUs were vested as of the date of this registration statement. From January 1, 2023 through the date of this registration statement, 579,498 TRSUs were legally granted, of which 144,841 TRSUs were vested as of the date of this registration statement. Such awards under the 2021 Plan were granted to employees and directors of the Company or its subsidiaries. The foregoing issuances were made under an exemption from registration provided by either (i) Rule 701 under the Securities Act as transactions pursuant to compensatory benefit plans and contracts relating to compensation; or (ii) Section 4(a)(2) of the Securities Act as transactions by an issuer not involving any public offering. Any outstanding and unvested PRSUs and TRSUs will vest in connection with this offering.

2020 ESPP Issuances

In December 2021, the Company issued 287,209 shares of its common stock through sales under the 2020 ESPP and received proceeds of approximately $3.2 million from such sales. In April 2022, the Company issued 5,125 shares of its common stock through sales under the 2020 ESPP and received proceeds of $78,310 from such sales. Such sales under the 2020 ESPP were made to certain employees and directors of the Company. The foregoing issuances were made under an exemption from registration provided by either (i) Rule 701 under the Securities Act as transactions pursuant to compensatory benefit plans and contracts relating to compensation; or (ii) Section 4(a)(2) of the Securities Act as transactions by an issuer not involving any public offering.

Item 16. Exhibits and Financial Statement Schedules.

(a) Exhibits: The list of exhibits set forth under "*Exhibit Index*" at the end of this registration statement is incorporated herein by reference.

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 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.

EXHIBIT INDEX

Exhibit Number	Description
1.1*	Form of Underwriting Agreement
2.1**+‡	Purchase and Sale Agreement, dated December 17, 2019, between Devon Energy Production Company, L.P. and BKV Barnett, LLC
2.2**+	First Amendment to Purchase and Sale Agreement, dated April 13, 2020, among Devon Energy Production Company, L.P., BKV Barnett, LLC and, solely with respect to the sections listed therein, BKV Oil & Gas Capital Partners, L.P.
2.3**+	Purchase and Sale Agreement, dated May 18, 2022, between XTO Energy Inc., Barnett Gathering, LLC, BKV North Texas, LLC and BKV Midstream, LLC
3.1**	Amended and Restated Certificate of Incorporation of BKV Corporation, as currently in effect
3.2**	Bylaws of BKV Corporation, as currently in effect
3.3**	Form of Second Amended and Restated Certificate of Incorporation of BKV Corporation, to be in effect upon completion of this offering
3.4**	Form of Amended and Restated Bylaws of BKV Corporation, to be in effect upon completion of this offering
4.1**	Form of Common Stock Certificate
5.1*	Opinion of Baker Botts L.L.P. as to the legality of the securities being registered
10.1**+	Credit Agreement, dated June 16, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.2**	Amended and Restated Loan Agreement, dated June 15, 2022, between Banpu North America Corporation and BKV Corporation, in the amount of $116,000,000
10.3**	Amended and Restated Loan Agreement, dated June 15, 2022, between Banpu North America Corporation and BKV Corporation, in the amount of $75,000,000
10.4**+	Revolving Credit Agreement, dated August 24, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.5**	Form of Stockholders' Agreement to be entered into between BKV Corporation and Banpu North America Corporation
10.6**	Form of Amended and Restated Tax Sharing Agreement to be entered into between BKV Corporation and Banpu North America Corporation
10.7**†‡	BKV Corporation 2021 Long Term Incentive Plan, adopted January 1, 2021 (the "2021 Plan")
10.8**†	First Amendment to the 2021 Plan, dated November 5, 2021
10.9**†‡	Form of Time Restricted Stock Unit Award and Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2021 Plan
10.10**†	Form of Time Restricted Stock Unit Award Notice and Award Agreement under the 2021 Plan
10.11**†	BKV Corporation 2020 Employee Stock Purchase Plan, adopted July 16, 2020
10.12**†	First Amendment to the BKV Corporation 2020 Employee Stock Purchase Plan, dated November 5, 2021
10.13**†	Second Amendment to the BKV Corporation 2020 Employee Stock Purchase Plan, dated April 21, 2022
10.14**†	BKV Corporation 2022 Equity and Incentive Compensation Plan (the "2022 Plan")
10.15**†‡	Form of Time Restricted Stock Unit Award and Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2022 Plan (CEO)

Exhibit Number	Description
10.16**†‡	Form of Time Restricted Stock Unit Award and Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2022 Plan (Non-CEO Employee)
10.17**†	Form of Restricted Stock Unit Award Notice and Award Agreement under the 2022 Plan (Director)
10.18**†	Form of Director and Officer Indemnity Agreement
10.19**†	Employment Agreement, dated August 4, 2020, between BKV Corporation and Christopher P. Kalnin
10.20**†	Employment Agreement, dated January 11, 2021, between BKV Corporation and John T. Jimenez
10.21**†	Employment Agreement, dated February 18, 2020, between Kalnin Ventures LLC and Eric Jacobsen
10.22**†	Employment Agreement, dated January 15, 2021, between BKV Corporation and Brid Kealey
10.23**†	Employment Agreement, dated October 15, 2018, between Kalnin Ventures LLC and Lindsay B. Larrick
10.24**†	Employment Agreement, dated April 1, 2018, between Kalnin Ventures LLC and An Sao (Ethan) Ngo
10.25**+	Limited Liability Company Agreement of BKV-BPP Power, LLC, dated October 29, 2021
10.26**†	BKV Corporation Non-Employee Director Compensation Program
10.27**+	Credit Facility, dated December 22, 2021, among BKV Corporation, Oversea-Chinese Banking Corporation Limited and the guarantors party thereto
10.28**+	Credit Facility, dated February 7, 2022, among BKV Corporation, Standard Chartered Bank, BKV Chaffee Corners, LLC, BKV Chelsea, LLC, BKV Operating, LLC and BKV Barnett, LLC
10.29**	First Amendment, dated November 11, 2022, to Credit Agreement, dated June 16, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.30**	First Amendment, dated November 11, 2022, to Revolving Credit Agreement, dated August 24, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.31**†	Letter Agreement, dated November 14, 2022, between Kalnin Ventures, LLC and Barry Turcotte
21.1	List of Subsidiaries of BKV Corporation
23.1	Consent of PricewaterhouseCoopers LLP (BKV Corporation)
23.2	Consent of PricewaterhouseCoopers LLP (ExxonMobil Barnett Assets)
23.3	Consent of Ryder Scott Company, L.P.
23.4*	Consent of Baker Botts L.L.P. (included as part of Exhibit 5.1 hereto)
24.1**	Power of Attorney (included on the signature page of the initial filing of the registration statement)
24.2**	Power of Attorney for Barry S. Turcotte
99.1**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2020 (SEC Pricing) (Barnett Assets)
99.2**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2020 (SEC Pricing) (Chaffee Corners Assets)

Exhibit Number	Description
99.3**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2020 (SEC Pricing) (Chelsea Assets)
99.4**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2020 (SEC Pricing) (BKV Assets)
99.5**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (Barnett Assets)
99.6**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (Chaffee Corners Assets)
99.7**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (Chelsea Assets)
99.8**	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (BKV Assets)
99.9	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (Barnett Assets)
99.10	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (Chaffee Corners Assets)
99.11	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (Chelsea Assets)
99.12	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (BKV Assets)
99.13	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (North Texas Assets)
99.14	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (NYMEX Strip Pricing) (Barnett Assets)
99.15	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (NYMEX Strip Pricing) (Chaffee Corners Assets)
99.16	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (NYMEX Strip Pricing) (Chelsea Assets)
99.17	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (NYMEX Strip Pricing) (BKV Assets)
99.18	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (NYMEX Strip Pricing) (North Texas Assets)
107**	Calculation of Filing Fee Table

* To be filed by amendment.

** Previously filed.

† Compensatory plan or arrangement.

\+ Certain schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The registrant undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

‡ Certain portions of this exhibit have been redacted pursuant to Item 601(b)(2)(ii) or Item 601(b)(10)(iv), as applicable, of Regulation S-K. The registrant agrees to furnish supplementally an unredacted copy of this exhibit to the SEC upon request.

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 Denver, State of Colorado, on this 14th day of April, 2023.

BKV CORPORATION

By: /s/ Christopher P. Kalnin
Christopher P. Kalnin
Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Name	Title	Date
/s/ Christopher P. Kalnin Christopher P. Kalnin	Chief Executive Officer and Director (Principal Executive Officer)	April 14, 2023
* John T. Jimenez	Chief Financial Officer (Principal Financial Officer)	April 14, 2023
* Barry S. Turcotte	Chief Accounting Officer (Principal Accounting Officer)	April 14, 2023
* Chanin Vongkusolkit	Chairman of the Board	April 14, 2023
* Somruedee Chaimongkol	Director	April 14, 2023
* Joseph R. Davis	Director	April 14, 2023
* Akaraphong Dayananda	Director	April 14, 2023
* Carla S. Mashinski	Director	April 14, 2023
* Thiti Mekavichai	Director	April 14, 2023
* Charles C. Miller III	Director	April 14, 2023
* Sunit S. Patel	Director	April 14, 2023

Name	Title	Date
* Anon Sirisaengtaksin	Director	April 14, 2023
* Sinon Vongkusolkit	Director	April 14, 2023

*By: /s/ Christopher P. Kalnin
Christopher P. Kalnin
Attorney-in-fact

Exhibit 21.1

List of Subsidiaries of BKV Corporation

Name	**State or Other Jurisdiction of Incorporation or Organization**
BKV Barnett, LLC	Delaware
BKV Chaffee Corners, LLC	Delaware
BKV Chelsea, LLC	Delaware
BKV dCarbon High West, LLC	Delaware
BKV dCarbon Temple, LLC	Delaware
BKV dCarbon Ventures, LLC	Delaware
BKVerde, LLC	Delaware
BKV Midstream, LLC	Delaware
BKV North Texas, LLC	Delaware
BKV Operating, LLC	Delaware
Kalnin Ventures LLC	Colorado

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the use in this Registration Statement on Form S-1 of BKV Corporation of our report dated April 13, 2023 relating to the financial statements of BKV Corporation, which appears in this Registration Statement. We also consent to the reference to us under the heading “Experts” in such Registration Statement.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
April 14, 2023

Exhibit 23.2

CONSENT OF INDEPENDENT AUDITORS

We hereby consent to the use in this Registration Statement on Form S-1 of BKV Corporation of our report dated September 12, 2022 relating to the statements of revenues and direct operating expenses of the Barnett Assets of XTO Energy Inc. and Barnett Gathering, LLC, which appears in this Registration Statement. We also consent to the reference to us under the heading “Experts” in such Registration Statement.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
April 14, 2023

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the references to our firm in this Registration Statement on Form S-1 for BKV Corporation, and to the use of information from, and the inclusion of, our reports, (i) dated October 21, 2022, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of Kalnin Ventures, LLC referred to as the Barnett Assets as of December 31, 2020, (ii) dated October 21, 2022, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold interests of Kalnin Ventures, LLC referred to as the Chaffee Corners Assets as of December 31, 2020, (iii) dated October 21, 2022, with respect to the estimates of proved and probable reserves, future production and income attributable to certain leasehold interests of Kalnin Ventures, LLC referred to as the Chelsea Assets as of December 31, 2020, (iv) dated October 21, 2022, with respect to the estimates of proved and probable reserves, future production and income attributable to certain leasehold interests of Kalnin Ventures, LLC referred to as the BKV Assets as of December 31, 2020, (v) dated October 21, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Barnett Assets as of December 31, 2021, (vi) dated October 21, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chaffee Corners Assets as of December 31, 2021, (vii) dated October 21, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chelsea Assets as of December 31, 2021, (viii) dated October 21, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the BKV Assets as of December 31, 2021, (ix) dated December 17, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Barnett Assets as of December 31, 2022, (x) dated December 17, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chaffee Corners Assets as of December 31, 2022, (xi) dated December 17, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Chelsea Assets as of December 31, 2022, (xii) dated December 17, 2022, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the BKV Assets as of December 31, 2022, (xiii) dated December 17, 2022, with respect to the estimates of proved and probable reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the North Texas Assets as of December 31, 2022, (xiv) dated January 16, 2023, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Barnett Assets, using a NYMEX Alternate Pricing Scheme, as of December 31, 2022, (xv) dated January 16, 2023, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chaffee Corners Assets, using a NYMEX Alternate Pricing Scheme, as of December 31, 2022, (xvi) dated January 16, 2023, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chelsea Assets, using a NYMEX Alternate Pricing Scheme, as of December 31, 2022, (xvii) dated January 16, 2023, with respect to the estimates of proved, probable and possible reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the BKV Assets, using a NYMEX Alternate Pricing Scheme, as of December 31, 2022, and (xviii) dated January 16, 2023, with respect to the estimates of proved and probable reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the North Texas Assets, using a NYMEX Alternate Pricing Scheme, as of December 31, 2022, each in this Registration Statement. We further consent to the reference to our firm under the heading “Experts” in this Registration Statement and related prospectus.

/s/ Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Denver, Colorado
April 14, 2023

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

Exhibit 99.9

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

BARNETT ASSETS

SEC Parameters

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

December 17, 2022

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corp. (BKV) referred to as the Barnett Assets as of December 31, 2022. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Barnett Assets evaluated by Ryder Scott account for a portion of BKV Corp's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 62 percent of the total proved, 89 percent of the total probable and 51 percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corp.
Barnett Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	932	0	698	1,630
Plant Products – Mbbl	140,272	11,757	36,575	188,604
Gas – MMcf	1,925,719	204,712	505,583	2,636,014
Income Data ($M)				
Future Gross Revenue	$ 14,872,705	$ 1,481,877	$ 4,089,392	$ 20,443,974
Deductions	5,222,342	486,733	1,645,107	7,354,182
Future Net Income (FNI)	$ 9,650,363	$ 995,144	$ 2,444,285	$ 13,089,792
Discounted FNI @ 10%	$ 4,228,165	$ 313,096	$ 817,995	$ 5,359,256

	Probable		
	Developed Non-Producing	Undeveloped	Total Probable
Net Reserves			
Oil/Condensate – Mbbl	0	1,556	1,556
Plant Products – Mbbl	25,422	39,319	64,741
Gas – MMcf	356,434	431,946	788,380
Income Data ($M)			
Future Gross Revenue	$ 2,720,817	$ 3,750,050	$ 6,470,867
Deductions	906,106	1,633,039	2,539,145
Future Net Income (FNI)	$ 1,814,711	$ 2,117,011	$ 3,931,722
Discounted FNI @ 10%	$ 363,777	$ 427,549	$ 791,326

	Possible		
	Developed Non-Producing	Undeveloped	Total Possible
Net Reserves			
Oil/Condensate – Mbbl	0	789	789
Plant Products – Mbbl	8,146	16,876	25,022
Gas – MMcf	84,124	161,074	245,198
Income Data ($M)			
Future Gross Revenue	$ 703,086	$ 1,467,399	$ 2,170,485
Deductions	214,910	731,900	946,810
Future Net Income (FNI)	$ 488,176	$ 735,499	$ 1,223,675
Discounted FNI @ 10%	$ 69,700	$ 92,301	$ 162,001

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. All gas reserves volumes are reported on an "as sold" basis. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 73 percent and liquid hydrocarbon reserves account for the remaining 27 percent of total future gross revenue from proved reserves. Gas reserves account for approximately 70 percent and liquid hydrocarbon reserves account for the remaining 30 percent of total future gross revenue from probable reserves. Gas reserves account for approximately 64 percent and liquid hydrocarbon reserves account for the remaining 36 percent of total future gross revenue from possible reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 6,099,770	$ 1,036,569	$ 232,242
12	$ 4,778,036	$ 613,312	$ 114,449
15	$ 4,109,598	$ 427,805	$ 69,125
20	$ 3,334,849	$ 244,898	$ 30,568

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved, probable, and possible developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered." 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." Possible reserves are "those additional reserves which are less certain to be recovered than probable reserves" and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible developed non-producing as well as all of the proved, probable, and possible undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark prices in effect on December 31, 2022. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain gas firm transportation fees, certain NGL fractionation and transportation fees, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices	Average Probable Realized Prices	Average Possible Realized Prices
North America						
United States	Oil/Condensate	WTI Cushing	$93.67/bbl	$86.92/bbl	$86.92/bbl	$86.92/bbl
	NGLs	WTI Cushing	$93.67/bbl	$30.10/bbl	$30.10/bbl	$30.10/bbl
	Gas	Henry Hub	$6.358/MMBTU	$6.03/Mcf	$6.07/Mcf	$6.04/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gas gathering and transportation costs were included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness using information furnished by BKV for this purpose. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved developed non-producing and proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

COLORADO LICENSED
STEPHEN E. GARDNER
S.E.G.
44720
12/20/2022
PROFESSIONAL ENGINEER

SEG (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

CHAFFEE CORNERS ASSETS

SEC Parameters

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

December 17, 2022

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold interests of BKV Corp. (BKV) referred to as the Chaffee Corners Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Chaffee Corners Assets evaluated by Ryder Scott account for a portion of BKV Corp's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 1 percent of the total proved, 1 percent of the total probable and 4 percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
BKV Corp.
Chaffee Corners Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing[1]	Undeveloped	Proved
Net Reserves				
Gas – MMcf	72,789	0	12,695	85,484
Income Data ($M)				
Future Gross Revenue	$ 449,685	$ 0	$ 78,429	$ 528,114
Deductions	71,706	68	14,341	86,115
Future Net Income (FNI)	$ 377,979	$ (68)	$ 64,088	$ 441,999
Discounted FNI @ 10%	$ 174,030	$ (62)	$ 28,971	$ 202,939

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

	Total Probable Undeveloped	Total Possible Undeveloped
Net Reserves		
Gas – MMcf	17,636	31,922
Income Data ($M)		
Future Gross Revenue	$ 108,956	$ 197,213
Deductions	39,801	84,791
Future Net Income (FNI)	$ 69,155	$ 112,422
Discounted FNI @ 10%	$ 14,904	$ 17,348

All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved, probable, and possible reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 226,896	$ 19,518	$ 24,512
12	$ 183,927	$ 11,491	$ 12,317
15	$ 161,792	$ 7,868	$ 7,327
20	$ 135,670	$ 4,221	$ 2,853

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered." 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." Possible reserves are "those additional reserves which are less certain to be recovered than probable reserves" and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved, probable and possible reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark price in effect on December 31, 2022. The initial SEC hydrocarbon price was determined using the 12-month average first-day-of-the-month benchmark price appropriate to the geographic area where the hydrocarbons are sold. The benchmark price is prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark price" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark price for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Proved Realized Price	Average Probable Realized Price	Average Possible Realized Price
North America	Gas	Henry Hub	$6.358/MMBTU	$6.18/Mcf	$6.18/Mcf	$6.18/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating costs. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

COLORADO LICENSED
STEPHEN E. GARDNER
S.E.G.
44720
12/20/2022
PROFESSIONAL ENGINEER

SEG (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.11

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

CHELSEA ASSETS

SEC Parameters

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

December 17, 2022

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corp. (BKV) referred to as the Chelsea Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Chelsea Assets evaluated by Ryder Scott account for a portion of BKV Corp's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 6 percent of the total proved, 4 percent of the total probable and 28 percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corp.
Chelsea Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing[1]	Undeveloped	Proved
Net Reserves				
Gas – MMcf	209,818	0	143,054	352,872
Income Data ($M)				
Future Gross Revenue	$ 1,182,519	$ 0	$ 808,029	$ 1,990,548
Deductions	357,599	376	264,370	622,345
Future Net Income (FNI)	$ 824,920	$ (376)	$ 543,659	$ 1,368,203
Discounted FNI @ 10%	$ 403,882	$ (345)	$ 220,551	$ 624,088

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

	Total Probable Undeveloped	Total Possible Undeveloped
Net Reserves		
Gas – MMcf	60,440	215,821
Income Data ($M)		
Future Gross Revenue	$ 341,372	$ 1,214,137
Deductions	129,692	509,341
Future Net Income (FNI)	$ 211,680	$ 704,796
Discounted FNI @ 10%	$ 58,991	$ 136,113

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved, probable, and possible reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 701,737	$ 73,200	$ 181,490
12	$ 561,862	$ 48,114	$ 103,463
15	$ 488,768	$ 36,075	$ 69,978
20	$ 401,763	$ 23,125	$ 38,003

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.” 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.” Possible reserves are “those additional reserves which are less certain to be recovered than probable reserves” and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark price in effect on December 31, 2022. The initial SEC hydrocarbon price was determined using the 12-month average first-day-of-the-month benchmark price appropriate to the geographic area where the hydrocarbons are sold. The benchmark price is prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark price" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark price for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Proved Realized Price	Average Probable Realized Price	Average Possible Realized Price
North America	Gas	Henry Hub	$6.358/MMBTU	$5.64/Mcf	$5.65/Mcf	$5.63/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating costs. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.12

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

BKV ASSETS

SEC Parameters

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

December 17, 2022

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corp. (BKV) referred to as the BKV Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the BKV Assets evaluated by Ryder Scott account for a portion of BKV Corp's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 7 percent of the total proved, 5 percent of the total probable and 17 percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corp.
BKV Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing[1]	Undeveloped	Proved
Net Reserves				
Gas – MMcf	266,438	0	195,552	461,990
Income Data ($M)				
Future Gross Revenue	$ 1,510,469	$ 0	$ 1,110,932	$ 2,621,401
Deductions	448,419	673	392,813	841,905
Future Net Income (FNI)	$ 1,062,050	$ (673)	$ 718,119	$ 1,779,496
Discounted FNI @ 10%	$ 542,822	$ (616)	$ 291,168	$ 833,374

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

	Total Probable Undeveloped	Total Possible Undeveloped
Net Reserves		
Gas – MMcf	62,403	132,061
Income Data ($M)		
Future Gross Revenue	$ 354,158	$ 743,295
Deductions	135,962	319,735
Future Net Income (FNI)	$ 218,196	$ 423,560
Discounted FNI @ 10%	$ 61,941	$ 84,869

All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved, probable, and possible reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 932,534	$ 76,614	$ 112,213
12	$ 753,705	$ 50,670	$ 65,102
15	$ 659,827	$ 38,148	$ 44,706
20	$ 547,565	$ 24,598	$ 25,020

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.” 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.” Possible reserves are “those additional reserves which are less certain to be recovered than probable reserves” and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark price in effect on December 31, 2022. The initial SEC hydrocarbon price was determined using the 12-month average first-day-of-the-month benchmark price appropriate to the geographic area where the hydrocarbons are sold. The benchmark price is prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark price" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Proved Realized Price	Average Probable Realized Price	Average Possible Realized Price
North America	Gas	Henry Hub	$6.358/MMBTU	$5.67/Mcf	$5.68/Mcf	$5.63/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating costs. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

NORTH TEXAS ASSETS

SEC Parameters

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

December 17, 2022

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved and probable reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corp. (BKV) referred to as the North Texas Assets as of December 31, 2022. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the North Texas Assets evaluated by Ryder Scott account for a portion of BKV Corp's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 24 percent of the total proved, 1 percent of the total probable and zero percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests
BKV Corp.
North Texas Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	179	0	60	239
Plant Products – Mbbl	17,313	1,498	4,085	22,896
Gas – MMcf	994,132	124,411	200,773	1,319,316
Income Data ($M)				
Future Gross Revenue	$ 5,797,831	$ 700,063	$ 1,162,341	$ 7,660,235
Deductions	2,423,881	255,181	495,118	3,174,180
Future Net Income (FNI)	$ 3,373,950	$ 444,882	$ 667,223	$ 4,486,055
Discounted FNI @ 10%	$ 1,602,617	$ 125,401	$ 206,827	$ 1,934,845

	Total Probable Non-Producing
Net Reserves	
Oil/Condensate – Mbbl	0
Plant Products – Mbbl	136
Gas – MMcf	10,648
Income Data ($M)	
Future Gross Revenue	$ 60,038
Deductions	22,551
Future Net Income (FNI)	$ 37,487
Discounted FNI @ 10%	$ 7,927

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. All gas reserves volumes are reported on an “as sold” basis. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion and development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 92 percent and liquid hydrocarbon reserves account for the remaining 8 percent of total future gross revenue from proved reserves. Gas reserves account for approximately 94 percent and liquid hydrocarbon reserves account for the remaining 6 percent of total future gross revenue from probable reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022	
Discount Rate Percent	Total Proved	Total Probable
8	$ 2,192,350	$ 10,259
12	$ 1,730,861	$ 6,216
15	$ 1,494,471	$ 4,407
20	$ 1,218,578	$ 2,576

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved and probable reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS and GUIDELINES" in this report. The developed proved and probable non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved and probable gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved and probable reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.” 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.” Possible reserves are “those additional reserves which are less certain to be recovered than probable reserves” and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved and probable reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved and probable non-producing as well as all of the proved undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved and probable production and income, we have relied upon data furnished by BKV with respect to property interests acquired, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved and probable reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved and probable reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark prices in effect on December 31, 2022. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices	Average Probable Realized Prices
North America					
United States	Oil/Condensate	WTI Cushing	$93.67/bbl	$88.12/bbl	N/A
	NGLs	WTI Cushing	$93.67/bbl	$29.05/bbl	$29.07
	Gas	Henry Hub	$6.358/MMBTU	$5.65/Mcf	$5.62/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by BKV. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved and probable developed non-producing and proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

COLORADO LICENSED
STEPHEN E. GARDNER
S.E.G.
44720
12/20/2022
PROFESSIONAL ENGINEER

SEG (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

BARNETT ASSETS

SEC Parameters
(NYMEX Alternate Pricing Scheme)

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 16, 2023

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corp. (BKV) referred to as the Barnett Assets as of December 31, 2022. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations); except that they were based on varying price and constant cost assumptions provided by BKV. This pricing scenario is considered an “Alternate Pricing Scheme” in accordance with the above referenced Final Rule, Section II, Item B, Paragraph 3. Such forecasts were based on projected escalations or other forward-looking changes to current prices as noted. Our third party study, completed on January 16, 2023 and presented herein was prepared for public disclosure by BKV, as an alternate pricing scheme, in filings made with the SEC in accordance with the disclosure requirements set forth by the SEC regulations. The income data for the reserves volumes were estimated using NYMEX Futures Strip prices as of December 31, 2022.

The properties referred to as the Barnett Assets evaluated by Ryder Scott account for a portion of BKV’s total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 61 percent of the total proved, 88 percent of the total probable and 44 percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on varying NYMEX Futures Strip pricing assumptions provided by BKV and are explained in more detail later in this report. As a result of both economic and political forces, there is substantial uncertainty regarding the forecasting of future hydrocarbon prices. Consequently, actual future prices may vary considerably from the prices assumed in this report. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS (NYMEX Alternate Pricing Scheme)
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corp.
Barnett Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	899	0	506	1,405
Plant Products – Mbbl	134,055	11,754	32,852	178,661
Gas – MMcf	1,851,061	203,188	483,211	2,537,460
Income Data ($M)				
Future Gross Revenue	$ 9,932,636	$ 1,030,033	$ 2,668,844	$ 13,631,513
Deductions	4,608,933	467,598	1,477,561	6,554,092
Future Net Income (FNI)	$ 5,323,703	$ 562,435	$ 1,191,283	$ 7,077,421
Discounted FNI @ 10%	$ 2,409,509	$ 136,193	$ 293,375	$ 2,839,077

	Probable		
	Developed Non-Producing	Undeveloped	Total Probable
Net Reserves			
Oil/Condensate – Mbbl	0	1,072	1,072
Plant Products – Mbbl	25,420	29,770	55,190
Gas – MMcf	352,567	375,472	728,039
Income Data ($M)			
Future Gross Revenue	$ 1,899,927	$ 2,179,177	$ 4,079,104
Deductions	866,327	1,260,553	2,126,880
Future Net Income (FNI)	$ 1,033,600	$ 918,624	$ 1,952,224
Discounted FNI @ 10%	$ 170,913	$ 135,066	$ 305,979

	Possible		
	Developed Non-Producing	Undeveloped	Total Possible
Net Reserves			
Oil/Condensate – Mbbl	0	273	273
Plant Products – Mbbl	8,143	7,062	15,205
Gas – MMcf	83,986	103,029	187,015
Income Data ($M)			
Future Gross Revenue	$ 487,018	$ 577,946	$ 1,064,964
Deductions	207,747	356,389	564,136
Future Net Income (FNI)	$ 279,271	$ 221,557	$ 500,828
Discounted FNI @ 10%	$ 35,015	$ 20,093	$ 55,108

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion and development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 77 percent and liquid hydrocarbon reserves account for the remaining 23 percent of total future gross revenue from proved reserves. Gas reserves account for approximately 77 percent and liquid hydrocarbon reserves account for the remaining 23 percent of total future gross revenue from probable reserves. Gas reserves account for approximately 76 percent and liquid hydrocarbon reserves account for the remaining 24 percent of total future gross revenue from possible reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 3,252,965	$ 426,010	$ 82,715
12	$ 2,513,928	$ 221,464	$ 36,922
15	$ 2,140,412	$ 136,900	$ 20,211
20	$ 1,709,588	$ 59,355	$ 6,919

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a), except that they are based on price parameters which allow for future changes in current economic conditions as discussed in other sections of this report, whereas the definition approved by the SEC assumes constant price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved, probable and possible developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered." 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." Possible reserves are "those additional reserves which are less certain to be recovered than probable reserves" and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

It should be noted that the estimated quantities of reserves presented in this report, which were based on NYMEX Futures Strip prices and constant cost parameters, may differ from the quantities of reserves which would be estimated using constant current price and cost parameters as prescribed by the SEC guidelines.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible developed non-producing as well as all of the proved, probable, and possible undeveloped status categories included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on costs and the pricing assumptions provided to us, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined; which for this report, as stated previously, are based on pricing and cost parameters provided by and requested to be used by BKV.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product price assumptions, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations and included as a price sensitivity case as allowed by SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The forecast hydrocarbon price parameters used in this report, based on NYMEX Futures Strip prices as of December 31, 2022, were specified by BKV and are noted below. Estimates of future price parameters have been revised in the past because of changes in governmental policies, changes in hydrocarbon supply and demand, and variations in general economic conditions. The price parameters used in this report may be revised in the future for similar reasons. Gas prices may be subject to seasonal variations and other factors and may lead to periodic curtailments by both buyers and sellers.

BKV furnished us with the forecast of the average benchmark prices assumed to be in effect beginning on December 31, 2022 and throughout the life of the properties.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain gas firm transportation fees, certain NGL fractionation and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the annual net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the annual total future gross revenue before production taxes and the total net reserves, by reserves category for these properties.

Geographic Area	AVERAGE BENCHMARK PRICES		AVERAGE REALIZED PRICES								
			Proved			Probable			Possible		
United States Year	WTI - Cushing $/Bbl	Henry Hub $/MMBtu	Oil/Cond $/Bbl	Plant Products $/Bbl	Gas $/Mcf	Oil/Cond $/Bbl	Plant Products $/Bbl	Gas $/Mcf	Oil/Cond $/Bbl	Plant Products $/Bbl	Gas $/Mcf
2023	$ 79.12	$ 4.26	$ 72.37	$ 24.76	$ 3.86	N/A	N/A	N/A	N/A	N/A	N/A
2024	$ 74.42	$ 4.27	$ 67.67	$ 23.03	$ 3.89	N/A	N/A	N/A	N/A	N/A	N/A
2025	$ 70.16	$ 4.39	$ 63.41	$ 21.47	$ 4.03	N/A	N/A	N/A	N/A	N/A	N/A
2026	$ 66.88	$ 4.46	$ 60.13	$ 20.26	$ 4.11	N/A	N/A	N/A	N/A	N/A	N/A
2027	$ 64.14	$ 4.50	$ 57.39	$ 19.26	$ 4.15	N/A	N/A	N/A	N/A	N/A	N/A
2028	$ 61.82	$ 4.57	$ 55.07	$ 18.41	$ 4.21	$ 55.07	$ 18.41	$ 4.26	N/A	N/A	N/A
2029	$ 59.81	$ 4.71	$ 53.06	$ 17.67	$ 4.35	$ 53.06	$ 17.67	$ 4.43	N/A	N/A	N/A
2030+	$ 58.04	$ 4.93	$ 51.29	$ 17.02	$ 4.57	$ 51.29	$ 17.02	$ 4.63	$ 51.29	$ 17.02	$ 4.58
Total Future Average Prices			$ 56.88	$ 18.46	$ 4.38	$ 51.54	$ 17.09	$ 4.58	$ 51.29	$ 17.02	$ 4.59

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gas gathering and transportation costs were included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness using information furnished by BKV for this purpose. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved developed non-producing and proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV. This report was based on forward looking price forecasts and may be filed as an additional pricing scenario to the SEC constant prices and costs case according to SEC guidelines.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2022 continuing education hours, Mr. Gardner participated in the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner attended the annual SPEE meeting held in Napa Valley, California as well as participated in various local SPEE and SIPES technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, SEC perspectives and other regulatory issues, geothermal energy, SRMS, and more.

Based on his educational background, professional training and more than 17 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.15

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

CHAFFEE CORNERS ASSETS

SEC Parameters
(NYMEX Alternate Pricing Scheme)

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 16, 2023

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold interests of BKV Corp. (BKV) referred to as the Chaffee Corners Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations); except that they were based on varying price and constant cost assumptions provided by BKV. This pricing scenario is considered an "Alternate Pricing Scheme" in accordance with the above referenced Final Rule, Section II, Item B, Paragraph 3. Such forecasts were based on projected escalations or other forward-looking changes to current prices as noted. Our third party study, completed on January 16, 2023 and presented herein was prepared for public disclosure by BKV, as an alternate pricing scheme, in filings made with the SEC in accordance with the disclosure requirements set forth by the SEC regulations. The income data for the reserves volumes were estimated using NYMEX Futures Strip prices as of December 31, 2022.

The properties referred to as the Chaffee Corners Assets evaluated by Ryder Scott account for a portion of BKV's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 1 percent of the total proved, 1 percent of the total probable and 4 percent of the total possible net hydrocarbon reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on varying NYMEX Futures Strip pricing assumptions provided by BKV and are explained in more detail later in this report. As a result of both economic and political forces, there is substantial uncertainty regarding the forecasting of future hydrocarbon prices. Consequently, actual future prices may vary considerably from the prices assumed in this report. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS (NYMEX Alternate Pricing Scheme)
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
BKV Corp.
Chaffee Corners Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing[1]	Undeveloped	Proved
Net Reserves				
Gas – MMcf	72,467	0	12,695	85,162
Income Data ($M)				
Future Gross Revenue	$ 325,901	$ 0	$ 56,328	$ 382,229
Deductions	70,011	68	14,342	84,421
Future Net Income (FNI)	$ 255,890	$ (68)	$ 41,986	$ 297,808
Discounted FNI @ 10%	$ 115,377	$ (62)	$ 16,937	$ 132,252

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

	Total Probable Undeveloped	Total Possible Undeveloped
Net Reserves		
Gas – MMcf	17,636	23,680
Income Data ($M)		
Future Gross Revenue	$ 81,920	$ 111,243
Deductions	39,801	56,669
Future Net Income (FNI)	$ 42,119	$ 54,574
Discounted FNI @ 10%	$ 6,225	$ 6,251

All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved, probable, and possible reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 148,990	$ 9,107	$ 9,772
12	$ 118,998	$ 4,161	$ 3,833
15	$ 103,631	$ 2,070	$ 1,519
20	$ 85,644	$ 147	$ (395)

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a), except that they are based on price parameters which allow for future changes in current economic conditions as discussed in other sections of this report, whereas the definition approved by the SEC assumes constant price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered." 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." Possible reserves are "those additional reserves which are less certain to be recovered than probable reserves" and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

It should be noted that the estimated quantities of reserves presented in this report, which were based on NYMEX Futures Strip prices and constant cost parameters, may differ from the quantities of reserves which would be estimated using constant current price and cost parameters as prescribed by the SEC guidelines.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on costs and the pricing assumptions provided to us, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined; which for this report, as stated previously, are based on pricing and cost parameters provided by and requested to be used by BKV.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, abandonment costs after salvage, product price assumptions, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations and included as a price sensitivity case as allowed by SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The forecast hydrocarbon price parameters used in this report, based on NYMEX Futures Strip prices as of December 31, 2022, were specified by BKV and are noted below. Estimates of future price parameters have been revised in the past because of changes in governmental policies, changes in hydrocarbon supply and demand, and variations in general economic conditions. The price parameters used in this report may be revised in the future for similar reasons. Gas prices may be subject to seasonal variations and other factors and may lead to periodic curtailments by both buyers and sellers.

BKV furnished us with the forecast of the average benchmark prices assumed to be in effect beginning on December 31, 2022 and throughout the life of the properties.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the annual net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the annual total future gross revenue before production taxes and the total net reserves, by reserves category for these properties.

		AVERAGE REALIZED PRICES		
Geographic Area	AVERAGE BENCHMARK PRICES	Proved	Probable	Possible
United States	Henry Hub	Gas	Gas	Gas
Year	$/MMBtu	$/Mcf	$/Mcf	$/Mcf
2023	$ 4.26	$ 4.02	N/A	N/A
2024	$ 4.27	$ 4.03	N/A	N/A
2025	$ 4.39	$ 4.15	N/A	N/A
2026	$ 4.46	$ 4.22	N/A	N/A
2027	$ 4.50	$ 4.26	N/A	N/A
2028	$ 4.57	$ 4.34	$ 4.34	N/A
2029	$ 4.71	$ 4.48	$ 4.48	$ 4.48
2030+	$ 4.93	$ 4.71	$ 4.71	$ 4.71
	Total Future Average Prices	$ 4.49	$ 4.64	$ 4.70

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV. This report was based on a forward looking price forecast and may be filed as an additional pricing scenario to the SEC constant prices and costs case according to SEC guidelines.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2022 continuing education hours, Mr. Gardner participated in the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner attended the annual SPEE meeting held in Napa Valley, California as well as participated in various local SPEE and SIPES technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, SEC perspectives and other regulatory issues, geothermal energy, SRMS, and more.

Based on his educational background, professional training and more than 17 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.16

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

CHELSEA ASSETS

SEC Parameters
(NYMEX Alternate Pricing Scheme)

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 16, 2023

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold interests of BKV Corp. (BKV) referred to as the Chelsea Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations); except that they were based on varying price and constant cost assumptions provided by BKV. This pricing scenario is considered an “Alternate Pricing Scheme” in accordance with the above referenced Final Rule, Section II, Item B, Paragraph 3. Such forecasts were based on projected escalations or other forward-looking changes to current prices as noted. Our third party study, completed January 16, 2023 and presented herein was prepared for public disclosure by BKV, as an alternate pricing scheme, in filings made with the SEC in accordance with the disclosure requirements set forth by the SEC regulations. The income data for the reserves volumes were estimated using NYMEX Futures Strip prices as of December 31, 2022.

The properties referred to as the Chelsea Assets evaluated by Ryder Scott account for a portion of BKV’s total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 6 percent of the total proved, 5 percent of the total probable and 32 percent of the total possible net hydrocarbon reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on varying NYMEX Futures Strip pricing assumptions provided by BKV and are explained in more detail later in this report. As a result of both economic and political forces, there is substantial uncertainty regarding the forecasting of future hydrocarbon prices. Consequently, actual future prices may vary considerably from the prices assumed in this report. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS (NYMEX Alternate Pricing Scheme)
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
BKV Corp.
Chelsea Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing[1]	Undeveloped	Proved
Net Reserves				
Gas – MMcf	205,072	0	142,980	348,052
Income Data ($M)				
Future Gross Revenue	$ 809,926	$ 0	$ 565,912	$ 1,375,838
Deductions	334,709	376	264,023	599,108
Future Net Income (FNI)	$ 475,217	$ (376)	$ 301,889	$ 776,730
Discounted FNI @ 10%	$ 230,065	$ (345)	$ 101,814	$ 331,534

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

	Total Probable Undeveloped	Total Possible Undeveloped
Net Reserves		
Gas – MMcf	59,765	206,937
Income Data ($M)		
Future Gross Revenue	$ 246,357	$ 860,194
Deductions	127,363	478,380
Future Net Income (FNI)	$ 118,994	$ 381,814
Discounted FNI @ 10%	$ 27,853	$ 60,892

All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved, probable, and possible reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 378,283	$ 35,998	$ 85,322
12	$ 294,272	$ 21,752	$ 43,766
15	$ 250,889	$ 15,191	$ 26,825
20	$ 200,106	$ 8,475	$ 11,683

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a), except that they are based on price parameters which allow for future changes in current economic conditions as discussed in other sections of this report, whereas the definition approved by the SEC assumes constant price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category are attributed to shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered." 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." Possible reserves are "those additional reserves which are less certain to be recovered than probable reserves" and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

It should be noted that the estimated quantities of reserves presented in this report, which were based on NYMEX Futures Strip prices and constant cost parameters, may differ from the quantities of reserves which would be estimated using constant current price and cost parameters as prescribed by the SEC guidelines.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on costs and the pricing assumptions provided to us, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined; which for this report, as stated previously, are based on pricing and cost parameters provided by and requested to be used by BKV.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, abandonment costs after salvage, product price assumptions, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations and included as a price sensitivity case as allowed by SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The forecast hydrocarbon price parameters used in this report, based on NYMEX Futures Strip prices as of December 31, 2022, were specified by BKV and are noted below. Estimates of future price parameters have been revised in the past because of changes in governmental policies, changes in hydrocarbon supply and demand, and variations in general economic conditions. The price parameters used in this report may be revised in the future for similar reasons. Gas prices may be subject to seasonal variations and other factors and may lead to periodic curtailments by both buyers and sellers.

BKV furnished us with the forecast of the average benchmark prices assumed to be in effect beginning on December 31, 2022 and throughout the life of the properties.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the annual net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the annual total future gross revenue before production taxes and the total net reserves, by reserves category for these properties.

		AVERAGE REALIZED PRICES		
Geographic Area	AVERAGE BENCHMARK PRICES	Proved	Probable	Possible
United States	Henry Hub	Gas	Gas	Gas
Year	$/MMBtu	$/Mcf	$/Mcf	$/Mcf
2023	$ 4.26	$ 3.49	N/A	N/A
2024	$ 4.27	$ 3.50	N/A	N/A
2025	$ 4.39	$ 3.63	N/A	N/A
2026	$ 4.46	$ 3.70	N/A	N/A
2027	$ 4.50	$ 3.73	$ 3.71	N/A
2028	$ 4.57	$ 3.81	$ 3.81	N/A
2029	$ 4.71	$ 3.95	$ 3.96	$ 3.94
2030+	$ 4.93	$ 4.17	$ 4.18	$ 4.16
	Total Future Average Prices	$ 3.95	$ 4.12	$ 4.16

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV. This report was based on a forward looking price forecast and may be filed as an additional pricing scenario to the SEC constant prices and costs case according to SEC guidelines.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner

COLORADO LICENSED
STEPHEN E. GARDNER
S.E.G.
44720
1/23/2023
PROFESSIONAL ENGINEER

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2022 continuing education hours, Mr. Gardner participated in the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner attended the annual SPEE meeting held in Napa Valley, California as well as participated in various local SPEE and SIPES technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, SEC perspectives and other regulatory issues, geothermal energy, SRMS, and more.

Based on his educational background, professional training and more than 17 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.17

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

BKV ASSETS

SEC Parameters
(NYMEX Alternate Pricing Scheme)

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 16, 2023

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corp. (BKV) referred to as the BKV Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations); except that they were based on varying price and constant cost assumptions provided by BKV. This pricing scenario is considered an "Alternate Pricing Scheme" in accordance with the above referenced Final Rule, Section II, Item B, Paragraph 3. Such forecasts were based on projected escalations or other forward-looking changes to current prices as noted. Our third party study, completed on January 16, 2023 and presented herein was prepared for public disclosure by BKV, as an alternate pricing scheme, in filings made with the SEC in accordance with the disclosure requirements set forth by the SEC regulations. The income data for the reserves volumes were estimated using NYMEX Futures Strip prices as of December 31, 2022.

The properties referred to as the BKV Assets evaluated by Ryder Scott account for a portion of BKV's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 8 percent of the total proved, 5 percent of the total probable and 20 percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on varying NYMEX Futures Strip pricing assumptions provided by BKV and are explained in more detail later in this report. As a result of both economic and political forces, there is substantial uncertainty regarding the forecasting of future hydrocarbon prices. Consequently, actual future prices may vary considerably from the prices assumed in this report. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS (NYMEX Alternate Pricing Scheme)
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corp.
BKV Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing(1)	Undeveloped	Proved
Net Reserves				
Gas – MMcf	261,609	0	195,171	456,780
Income Data ($M)				
Future Gross Revenue	$ 1,036,339	$ 0	$ 779,031	$ 1,815,370
Deductions	424,943	673	391,009	816,625
Future Net Income (FNI)	$ 611,396	$ (673)	$ 388,022	$ 998,745
Discounted FNI @ 10%	$ 306,874	$ (616)	$ 128,604	$ 434,862

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

	Total Probable Undeveloped	Total Possible Undeveloped
Net Reserves		
Gas – MMcf	59,040	124,748
Income Data ($M)		
Future Gross Revenue	$ 244,660	$ 519,363
Deductions	124,374	294,136
Future Net Income (FNI)	$ 120,286	$ 225,227
Discounted FNI @ 10%	$ 29,330	$ 38,947

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved, probable, and possible reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022		
Discount Rate Percent	Total Proved	Total Probable	Total Possible
8	$ 494,085	$ 37,541	$ 53,429
12	$ 387,596	$ 23,147	$ 28,700
15	$ 332,467	$ 16,453	$ 18,434
20	$ 267,745	$ 9,519	$ 9,030

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved, probable and possible reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a), except that they are based on price parameters which allow for future changes in current economic conditions as discussed in other sections of this report, whereas the definition approved by the SEC assumes constant price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category are attributed to shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV’s request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.” 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.” Possible reserves are “those additional reserves which are less certain to be recovered than probable reserves” and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

It should be noted that the estimated quantities of reserves presented in this report, which were based on NYMEX Futures Strip prices and constant cost parameters, may differ from the quantities of reserves which would be estimated using constant current price and cost parameters as prescribed by the SEC guidelines.

BKV’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved, probable, and possible undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on costs and the pricing assumptions provided to us, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined; which for this report, as stated previously, are based on pricing and cost parameters provided by and requested to be used by BKV.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, abandonment costs after salvage, product price assumptions , adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations, and included as a price sensitivity case as allowed by SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The forecast hydrocarbon price parameters used in this report, based on NYMEX Futures Strip prices as of December 31, 2022, were specified by BKV and are noted below. Estimates of future price parameters have been revised in the past because of changes in governmental policies, changes in hydrocarbon supply and demand, and variations in general economic conditions. The price parameters used in this report may be revised in the future for similar reasons. Gas prices may be subject to seasonal variations and other factors and may lead to periodic curtailments by both buyers and sellers.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

BKV furnished us with the forecast of the average benchmark prices assumed to be in effect beginning on December 31, 2022 and throughout the life of the properties.

In addition, the table below summarizes the annual net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the annual total future gross revenue before production taxes and the total net reserves, by reserves category for these properties.

		AVERAGE REALIZED PRICES		
Geographic Area	AVERAGE BENCHMARK PRICES	Proved	Probable	Possible
United States	Henry Hub	Gas	Gas	Gas
Year	$/MMBtu	$/Mcf	$/Mcf	$/Mcf
2023	$ 4.26	$ 3.53	N/A	N/A
2024	$ 4.27	$ 3.54	N/A	N/A
2025	$ 4.39	$ 3.66	N/A	N/A
2026	$ 4.46	$ 3.73	N/A	N/A
2027	$ 4.50	$ 3.77	$ 3.71	N/A
2028	$ 4.57	$ 3.84	$ 3.85	N/A
2029	$ 4.71	$ 3.98	$ 3.99	$ 3.93
2030+	$ 4.93	$ 4.21	$ 4.21	$ 4.16
	Total Future Average Prices	$ 3.97	$ 4.14	$ 4.16

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gas gathering and transportation costs were included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were reviewed by us for their reasonableness using information furnished by BKV for this purpose. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved, probable, and possible undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV. This report was based on a forward looking price forecast and may be filed as an additional pricing scenario to the SEC constant prices and costs case according to SEC guidelines.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2022 continuing education hours, Mr. Gardner participated in the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner attended the annual SPEE meeting held in Napa Valley, California as well as participated in various local SPEE and SIPES technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, SEC perspectives and other regulatory issues, geothermal energy, SRMS, and more.

Based on his educational background, professional training and more than 17 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

<u>POSSIBLE RESERVES (SEC DEFINITIONS)</u>

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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.

(v) 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.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.18

BKV CORP.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

NORTH TEXAS ASSETS

SEC Parameters
(NYMEX Alternate Pricing Scheme)

As of

December 31, 2022

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 16, 2023

BKV Corp.
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved and probable reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corp. (BKV) as of December 31, 2022. The subject properties are located in the state of Texas, referred to herein as the North Texas Assets. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations); except that they were based on varying price and constant cost assumptions provided by BKV. This pricing scenario is considered an "Alternate Pricing Scheme" in accordance with the above referenced Final Rule, Section II, Item B, Paragraph 3. Such forecasts were based on projected escalations or other forward-looking changes to current prices as noted. Our third party study, completed on January 16, 2023 and presented herein was prepared for public disclosure by BKV, as an alternate pricing scheme, in filings made with the SEC in accordance with the disclosure requirements set forth by the SEC regulations. The income data for the reserves volumes were estimated using NYMEX Futures Strip prices as of December 31, 2022.

The properties referred to as North Texas Assets evaluated by Ryder Scott account for a portion of BKV's total net proved, probable and possible reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 24 percent of the total proved, 1 percent of the total probable and zero percent of the total possible net reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on varying NYMEX Futures Strip pricing assumptions provided by BKV and are explained in more detail later in this report. As a result of both economic and political forces, there is substantial uncertainty regarding the forecasting of future hydrocarbon prices. Consequently, actual future prices may vary considerably from the prices assumed in this report. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS (NYMEX Alternate Pricing Scheme)
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corp.
North Texas Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	160	0	59	219
Plant Products – Mbbl	16,418	1,498	4,085	22,001
Gas – MMcf	938,235	124,411	187,689	1,250,335
Income Data ($M)				
Future Gross Revenue	$ 3,793,449	$ 488,980	$ 754,968	$ 5,037,397
Deductions	2,078,262	247,582	444,989	2,770,833
Future Net Income (FNI)	$ 1,715,187	$ 241,398	$ 309,979	$ 2,266,564
Discounted FNI @ 10%	$ 839,449	$ 39,254	$ 58,441	$ 937,144

	Total Probable Developed Non-Producing
Net Reserves	
Oil/Condensate – Mbbl	0
Plant Products – Mbbl	136
Gas – MMcf	10,648
Income Data ($M)	
Future Gross Revenue	$ 42,831
Deductions	21,931
Future Net Income (FNI)	$ 20,900
Discounted FNI @ 10%	$ 2,735

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion and development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 93 percent and liquid hydrocarbon reserves account for the remaining 7 percent of total future gross revenue from proved reserves. Gas reserves account for approximately 95 percent and liquid hydrocarbon reserves account for the remaining 5 percent of total future gross revenue from probable reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022	
Discount Rate Percent	Total Proved	Total Probable
8	$ 1,074,374	$ 4,037
12	$ 828,454	$ 1,822
15	$ 702,965	$ 915
20	$ 558,089	$ 99

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved and probable reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a), except that they are based on price parameters which allow for future changes in current economic conditions as discussed in other sections of this report, whereas the definition approved by the SEC assumes constant price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved and probable developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved and probable gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV’s request, this report addresses the proved and probable reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.” 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.” Possible reserves are “those additional reserves which are less certain to be recovered than probable reserves” and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and are presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserves categories that are included herein have not been adjusted to reflect these varying degrees of uncertainty associated with them and thus are not comparable.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved and probable reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

It should be noted that the estimated quantities of reserves presented in this report, which were based on NYMEX Futures Strip prices and constant cost parameters, may differ from the quantities of reserves which would be estimated using constant current price and cost parameters as prescribed by the SEC guidelines.

BKV’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved and probable developed non-producing as well as all of the proved undeveloped status categories included herein were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved, probable and possible oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on costs and the pricing assumptions provided to us, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined; which for this report, as stated previously, are based on pricing and cost parameters provided by and requested to be used by BKV.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests acquired, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product price assumptions, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved and probable reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved and probable reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations, and included as a price sensitivity case as allowed by SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The forecast hydrocarbon price parameters used in this report, based on NYMEX Futures Strip prices as of December 31, 2022, were specified by BKV and are noted below. Estimates of future price parameters have been revised in the past because of changes in governmental policies, changes in hydrocarbon supply and demand, and variations in general economic conditions. The price parameters used in this report may be revised in the future for similar reasons. Gas prices may be subject to seasonal variations and other factors and may lead to periodic curtailments by both buyers and sellers.

BKV furnished us with the forecast of the average benchmark prices assumed to be in effect beginning on December 31, 2022 and throughout the life of the properties.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain NGL fractionation and transportation fees, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the annual net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the annual total future gross revenue before production taxes and the total net reserves, by reserves category for these properties.

Geographic Area	AVERAGE BENCHMARK PRICES		AVERAGE REALIZED PRICES					
			Proved			Probable		
United States Year	WTI - Cushing $/Bbl	Henry Hub $/MMBtu	Oil/Cond $/Bbl	Plant Products $/Bbl	Gas $/Mcf	Oil/Cond $/Bbl	Plant Products $/Bbl	Gas $/Mcf
2023	$ 79.12	$ 4.26	$ 73.57	$ 23.71	$ 3.47	N/A	N/A	N/A
2024	$ 74.42	$ 4.27	$ 68.87	$ 21.98	$ 3.48	N/A	N/A	N/A
2025	$ 70.16	$ 4.39	$ 64.61	$ 20.42	$ 3.60	N/A	N/A	N/A
2026	$ 66.88	$ 4.46	$ 61.33	$ 19.21	$ 3.67	N/A	N/A	N/A
2027	$ 64.14	$ 4.50	$ 58.59	$ 18.21	$ 3.70	N/A	N/A	N/A
2028	$ 61.82	$ 4.57	$ 56.27	$ 17.36	$ 3.78	N/A	$ 17.36	$ 3.76
2029	$ 59.81	$ 4.71	$ 54.26	$ 16.62	$ 3.93	N/A	$ 16.62	$ 3.92
2030+	$ 58.04	$ 4.93	$ 52.49	$ 15.97	$ 4.17	N/A	$ 16.00	$ 4.14
Total Future Average Prices			$ 56.66	$ 17.35	$ 3.97	N/A	$ 16.23	$ 4.07

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by BKV. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were reviewed by us for their reasonableness using information furnished by BKV for this purpose. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification.

The proved and probable developed non-producing and proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV. This report was based on forward looking price forecasts and may be filed as an additional pricing scenario to the SEC constant prices and costs case according to SEC guidelines.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2022 continuing education hours, Mr. Gardner participated in the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner attended the annual SPEE meeting held in Napa Valley, California as well as participated in various local SPEE and SIPES technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, SEC perspectives and other regulatory issues, geothermal energy, SRMS, and more.

Based on his educational background, professional training and more than 17 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

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.*

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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 required 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.