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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025

OR

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

For the transition period from to

Commission file number 001-42282

BKV CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**85-0886382**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1200 17th Street, Suite 2100 **Denver, Colorado**	**80202**
(Address of Principal Executive Offices)	(Zip Code)

(720) 375-9680

Registrant's telephone number, including area code

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.01 Par Value	BKV	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes x No o

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

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

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

x

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

o

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

o

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

o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes o No x

The aggregate market value of the registrant's voting and non-voting common stock held by non-affiliates of the registrant on June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter, computed by reference to the last sale price of the registrant's common stock as reported by the New York Stock Exchange on such date, was approximately $424.9 million. This computation assumes that all executive officers and directors are affiliates of the registrant. Such assumption should not be deemed conclusive for any other purpose.

The registrant had 102,288,077 shares of common stock outstanding as of February 27, 2026.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report, to the extent not set forth herein, is incorporated by reference from the registrant's definitive 2026 Proxy Statement, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

Table of Contents

Glossary of Commonly Used Terms

The definitions set forth below include indicated terms in this Annual Report. All natural gas referred to in this Annual Report are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit.

"***2025 Equity Offering***" refers to the underwritten public offering of 6,900,000 shares of our common stock completed on December 3, 2025 for net proceeds of $170.1 million.

"***2030 Senior Notes***" refers to the $500.0 million aggregate principal amount of 7.50% senior unsecured notes due 2030 issued by BKV Upstream Midstream.

"***ABR***" refers to the alternative base rate.

"***Adjusted Free Cash Flow***" refers to net cash provided by (used in) operating activities, excluding cash paid for contingent consideration and changes in operating assets and liabilities, less total cash paid for capital expenditures (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.

"***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, BNAC, 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 91.1% of Banpu Power as of December 31, 2025.

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

"***Barnett Zero Project***" refers to BKV dCarbon Barnett Zero, LLC, a Delaware limited liability company and, as of May 8, 2025, a wholly-owned subsidiary of the BKV-CIP Joint Venture.

"***Bbl***" refers to one stock tank barrel, of 42 U.S. gallons liquid volume, used in this Annual Report on Form 10-K 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.

"***Bedrock Acquisition***" refers to the acquisition by BKV Upstream Midstream of 100% of the equity interests of BKV Barnett II (formerly known as Bedrock Production, LLC) from Bedrock Energy Partners, LLC, which closed on September 29, 2025.

"***BKV Barnett II***" refers to BKV Barnett II, LLC (formerly known as Bedrock Production, LLC), a Texas limited liability company and, following its acquisition on September 29, 2025, a wholly-owned subsidiary of BKV Upstream Midstream. BKV Barnett II and its subsidiaries own certain oil and gas producing properties and midstream assets in the Barnett Shale, including approximately 96,000 net acres, 1,121 operated wells, and related natural gas upstream, midstream, and other assets.

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

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

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

"***BKV-BPP Cotton Cove***" or "***BKV-BPP Cotton Cove Joint Venture***" refers to BKV-BPP Cotton Cove, LLC, a Delaware limited liability company and the joint venture between BKV dCarbon Ventures and BPPUS, in which we own an indirect 51% interest.

"***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 owned a 50% interest as of December 31, 2025. Following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, the BKV-BPP Power Joint Venture is owned 75% by BKV and 25% by BPPUS.

"***BKV-BPP Power Joint Venture Transaction***" refers to BKV's acquisition of an additional 25% interest in the BKV-BPP Power Joint Venture from BPPUS, which closed on January 30, 2026.

"***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.

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

"***BKV-CIP Joint Venture***" refers to BKV dCarbon Project, LLC, a Delaware limited liability company and the joint venture between BKV dCarbon Ventures and C Squared Solutions, Inc., in which we currently own a 51% interest.

"***BKV-CIP JV Agreement***" refers to the Limited Liability Company Agreement of BKV dCarbon Project, LLC, entered into on May 8, 2025, by BKV dCarbon Ventures, C Squared Solutions, Inc. and, for the limited purposes specified therein, BKV Corporation.

"***BKV Upstream Midstream***" refers to BKV Upstream Midstream, LLC, a wholly-owned subsidiary of BKV Corporation.

"***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 and a 49% interest in the BKV-BPP Cotton Cove Joint Venture as of December 31, 2025. Following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, BPPUS owns a 25% interest in the BKV-BPP Power Joint Venture.

"***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.

"***bylaws***" refers to the Second Amended and Restated Bylaws of BKV Corporation.

"***Carbon Sequestered Gas***" refers to a Scope 1, 2, and 3 carbon neutral natural gas product.

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

"***Chaffee***" refers to BKV Chaffee Corners, LLC, a Delaware limited liability company and, prior to its sale on June 14, 2024, a wholly-owned subsidiary of BKV Corporation.

"***certificate of incorporation***" refers to the Second Amended and Restated Certificate of Incorporation of BKV Corporation.

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

"***Class B Member***" refers to C Squared Solutions, Inc, a subsidiary of the Energy Transition Fund managed by Copenhagen Infrastructure Partners (CIP).

"CO_2" refers to carbon dioxide.

"CO_2e" refers to carbon dioxide equivalent.

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

"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.

"***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.

"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.

"***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.

"***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.

"***High West***" refers to High West Sequestration, LLC, a Louisiana limited liability company and wholly-owned subsidiary of BKV dCarbon Ventures.

"***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.

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

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

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

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

"***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.

"***MiQ Standard***" refers to a standalone framework to assess the methane emissions intensity and carbon (CO_{2e}) intensity at the asset level from each stage of the natural gas supply chain and some stages of the crude oil and natural gas liquids supply chain.

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

"***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.

"***Mt***" refers to million metric tons.

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

"***natural gas midstream business***" refers to the natural gas gathering, processing, and transportation business line.

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

"***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.

"***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.

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

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

"***NOL***" refers to net operating loss.

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

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

"***OPIS***" refers to a Dow Jones Company that surveys and collects price information and publishes benchmarks for various energy commodities.

"***Pad of the Future***" refers to our program of converting natural gas-powered instrument pneumatics to compressed air or electric power instruments on existing pads, combined with emission and leak surveys.

"***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.

"***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 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. 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.

"***PUCT***" refers to the Public Utility Commission of Texas.

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

"***RBL Credit Agreement***" refers to that certain reserve-based lending agreement dated as of June 11, 2024, as amended from time to time, among BKV Corporation, BKV Upstream Midstream, Citibank, N.A., as administrative agent, and the financial institutions party thereto.

"***Responsibly Sourced Gas***" or "***RSG***" refers to natural gas produced from a well which has gone through a third party environmental assessment and verification process and has a current TrustWell rating.

"***Revolving Credit Agreement***" refers to $100.0 million of commitments of unsecured revolving loans with Bangkok Bank Public Company Limited (New York Branch).

"***Revolving Credit Facilities***" refers to an uncommitted credit facilities with Oversea Chinese Banking Corporation and Standard Chartered Bank of up to $55.0 million and $50.0 million, respectively.

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

"***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 that result from the end use of an organization's products, as estimated per Category 11 (Use of Sold Product), 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.

"***Section 45I tax credits***" refers to tax credits provided under Section 45I of the Code.

"***Section 45Q tax credits***" refers to tax credits provided under Section 45Q of the Code.

"***SOFR***" refers to the secured overnight financing rate.

"***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 owner's Scope 2 emissions. For every 1,000 kilowatt-hours of electricity produced by an eligible solar facility, one renewable energy credit and one compliance premium is awarded. The combination of a renewable energy credit and a compliance premium is known as an SREC. 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.

"***Temple II***" refers to a second combined gas turbine and steam turbine power plant located in Temple, Texas, which power plant sits on the same site as Temple I and is owned by the BKV-BPP Power Joint Venture.

"***Temple Plants***" refers to Temple I and Temple II, collectively.

"***Term Loan Credit Agreement***" refers to a credit agreement with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent, which included $600.0 million of commitments for term loans used to solely to fund a portion of the purchase price for the Exxon Barnett Acquisition.

"***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***" refers to 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.

"***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.

SUMMARY OF RISK FACTORS

The following is a summary of some of the risks that could materially and adversely effect our business, financial condition, or results of operations. We describe these and other risks in greater detail under Item 1A., "*Risk Factors*."

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 reserves 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;
- integrating the assets held by BKV Barnett II into our business or achieving the anticipated benefits of the Bedrock Acquisition;

Risks Related to Our Power Generation Business

- extreme weather, transmission congestion, and changes to the regulatory environment;
- the operation of our power generation business through a joint venture that requires the consent of BPPUS for certain material actions;
- risks and hazards related to the operation or maintenance of electric generation facilities, including disruption of the fuel supplies necessary to generate power at the Temple Plants;
- the lack of long-term power sales agreements for the Temple Plants;

Risks Related to Our Retail Power Business

- the operation of our retail power business through a joint venture that requires the consent of BPPUS for certain material actions;
- market price risk and changes in law, regulation, or market structure resulting in unanticipated costs;
- our ability to maintain our retail electric provider certification;

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;

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;
- 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;
- 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 ventures 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;
- exemptions from certain reporting requirements for as long as we are an emerging growth company;

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 changing sentiments towards ESG matters and environmental conservation measures;
- reductions in demand for natural gas, NGL, and oil;
- risks related to climate change, including transitional, legal, political, financial, and physical risks;
- significant costs and liabilities related to environmental, health and safety laws, and regulations;
- potential tax law changes;
- complex and evolving laws and regulations regarding privacy and data protection;
- changes in U.S. foreign trade policies and international trade agreements;

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 are a “controlled company” within the meaning of the New York Stock Exchange ("NYSE") rules and, as a result, qualify for and 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 officers and/or directors as a result of their positions with, or ownership of common stock of, Banpu;
- the BKV-BPP Joint Venture Transaction is a related party transaction, which may create actual or perceived conflicts of interest;

Risks Related to Our Common Stock

- the impact of our lack of dividend payments on the market price of our common stock;
- we identified a material weakness in our internal control over financial reporting;
- future sales of our common stock could reduce the price of our common stock; and
- the price of our common stock has fluctuated substantially and may fluctuate substantially in the future.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact contained in this Annual Report on Form 10-K, 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 Annual Report on Form 10-K, 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 terms and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Such forward-looking statements include those described in "Item 1A. *Risk Factors*" in this Annual Report on Form 10-K, as well as the following factors, among others: statements about the anticipated benefits, opportunities and results with respect to the BKV-BPP Power Joint Venture Transaction and the Bedrock Acquisition, including any expected value creation from the BKV-BPP Power Joint Venture Transaction or the Bedrock Acquisition, and any reserves additions, midstream opportunities and other anticipated impacts from the Bedrock Acquisition, anticipated efficiencies, power plant reliability, and strategic growth and power purchase agreement opportunities relating to the BKV-BPP Power Joint Venture and the BKV-BPP Power Joint Venture Transaction, as well as guidance, projected or forecasted financial and operating results, future liquidity, leverage, results in certain basins, objectives, project timing, expectations and intentions, regulatory and governmental actions and other statements that are not historical facts. 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.

Forward-looking statements contained in this Annual Report on Form 10-K include, but are not limited to, statements about:

- our business strategy;
- our reserves;
- our financial strategy, liquidity, and capital required for our development programs;
- our relationship with our sponsor, Banpu and its affiliates, including future agreements with Banpu;
- actual and potential conflicts of interest relating to Banpu, its affiliates, and other entities in which members of our officers and directors are or may become involved;
- volatility in natural gas, NGL, and oil prices;
- our dividend policy;
- our drilling plans and the timing and amount of future production of natural gas, NGL, and oil;
- our hedging strategy and results;
- competition and government regulation;
- changes in trade regulation, including tariffs and other market factors;
- legal, regulatory, or environmental matters;
- marketing of natural gas, NGL, and oil;
- business or leasehold acquisitions and integration of acquired businesses, including the Bedrock Acquisition, with our business;
- 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 the Temple Plants;
- our plan to continue to build out our power generation business and to expand into retail power;
- our ability to develop, produce, and sell Carbon Sequestered Gas;
- our ability to effectively operate and grow our CCUS business;
- our ability to forecast annual CO_2 sequestration rates for our CCUS projects;
- our ability to reach final investment decision 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 ability to effectively operate and grow our retail power business;

- our anticipated Scope 1, 2, and 3 emissions from our owned and operated upstream and natural gas midstream businesses and our sustainability plans and goals, including our plans to offset our Scope 1, 2, and 3 emissions from our owned and operated upstream and natural gas midstream businesses;
- our ESG strategy and initiatives, including those relating to the generation and marketing of environmental attributes or new products seeking to benefit from ESG-related activities, and the continuation of government tax incentives applicable thereto;
- 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 weakness;
- the Bedrock Acquisition and the anticipated benefits thereof;
- BKV-BPP Power Joint Venture Transaction and the anticipated benefits thereof;
- the impact of the One Big Beautiful Bill Act of 2025 (the "OBBBA"); and
- our plans, objectives, expectations, and intentions.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur.

Undue reliance should not be placed on any forward-looking statement, which are based on predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We undertake no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the Securities and Exchange Commission (the "SEC").

PART I

ITEM 1. BUSINESS

Overview

BKV Corporation ("BKV," the "Company," "our," "we," and "us") is a forward-thinking, growth-driven energy company focused on creating long-term risk-adjusted stockholder value through the development of natural gas producing assets, the ownership and operation of natural gas-fired power generation assets, and selective accretive acquisitions. Our core businesses are the production of natural gas and the generation of natural gas-fired power from our owned and operated assets, supported by a closed-loop strategy enabled by our upstream, midstream, power, and CCUS businesses.

Our operations are supported by four business lines: natural gas production, natural gas midstream, power generation, and CCUS. Our operating approach is designed around a closed-loop model that aligns these business lines to support cost efficiency, commercial optimization, and operational reliability across the value chain. Through this approach, we retain operational control over the production, transportation, and processing of natural gas and provide multiple platforms for disciplined capital deployment, while meeting growing demand for low carbon natural gas and power.

For example, in the Barnett Shale, natural gas produced from our upstream assets is gathered and transported in part through our midstream systems. In November 2023, we commenced sequestration operations at our first CCUS project, and we currently expect our second and third CCUS projects to commence sequestration activities during the first and second quarter of 2026 with additional CCUS growth opportunities beyond 2026. Further, we are pursuing a power growth strategy that aligns with both our natural gas and CCUS businesses.

As part of our ongoing operations, we expect our owned and operated upstream and natural gas midstream businesses to achieve net-zero Scope 1 and Scope 2 greenhouse gas emissions during the early 2030s and net-zero Scope 1, Scope 2, and Scope 3 emissions by the late 2030s.

We believe our business model, experienced management team, and disciplined technology-enabled operations support our ability to create long-term, risk-adjusted stockholder value.

Initial Public Offering

On September 27, 2024, we completed our initial public offering ("IPO") of 15,000,000 shares of our common stock at a price to the public of $18.00 per share. We also granted the underwriters of our IPO a 30-day option to purchase up to 2,250,000 additional shares of common stock on the same terms. The underwriters partially exercised the option and, on October 28, 2024, purchased 701,003 additional shares of common stock. These sales of our common stock resulted in net proceeds of $265.7 million after deducting underwriter fees and offering expenses of $17.0 million. All shares sold were registered pursuant to a registration statement on Form S-1 (File No. 333-268469), as amended, which was declared effective by the SEC on September 25, 2024. We used $200.0 million to pay down a portion of our outstanding borrowings, including interest, under our RBL Credit Agreement, and $50.0 million to repay the outstanding balance, including interest, under our related party loan with BNAC, our majority stockholder. The remaining amounts were used for growth capital expenditures and other general corporate purposes.

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. We believe the following strategic priorities will help drive value creation and long-term success.

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. Our Pad of the Future program, which includes conversion of natural gas-powered instrument pneumatics to compressed air or electric power instruments on existing pads, combined with emission and leak surveys, is expected to significantly reduce our annual GHG emissions and improve pad efficiencies and operating revenue. We have also improved pad efficiencies and reduced lease operating costs through improvements including leveraging of data analytics to coordinate the workforce, prioritize high-value activity, and assess individual well profitability; automating critical plunger set points; in-sourcing key services such as slick-line, value re-builds, compression overhaul, and location repair and maintenance; and entering water share arrangements to reduce disposal and trucking cost. By combining our reserves into a growing asset base with vertically integrated components, we believe we can enhance margins and create a "closed-loop" emissions reduction strategy that reduces Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses and captures margin across the value chain.

Grow through opportunistic, synergistic acquisitions. A significant element of our business strategy is gaining scale through accretive acquisitions. We believe our business model, management team experience, and application of technology enable us to quickly and efficiently integrate additional upstream, midstream, power, and CCUS 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 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.

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 emissions from our owned and operated upstream and natural gas midstream businesses during the early 2030s. We believe we can achieve this through reductions in and offsets to our owned and operated upstream and natural gas midstream emissions from our Pad of the Future emissions reductions program and emissions monitoring and leak surveys, the retirement of SRECs generated by the BKV-BPP Power Joint Venture's solar facility, 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 and natural gas midstream businesses, CCUS for third parties is a focus of our business plan.

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 refracturing, 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" support our core values and provide us with confidence in our ability to successfully manage and grow our business.

Deliver robust returns to stockholders. We intend to prioritize delivering strong returns to our stockholders through our focus on creating stockholder value. 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 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. As of December 31, 2025, our total acreage position was approximately 563,000 net acres, substantially all of which was held by production. For the year ended December 31, 2025, our net daily production (after giving effect to the Bedrock Acquisition) averaged 835.5 MMcfe/d, consisting of approximately 80% natural gas and approximately 20% NGLs. As of December 31, 2025, our total proved reserves of 5,921 Bcfe had an estimated 7.4% year-over-year average base decline rate over the next 10 years.

As of December 31, 2025, our Barnett acreage position was approximately 544,000 net acres, substantially all of which was held by production. Our average daily Barnett production of approximately 742.0 MMcfe/d for the year ended December 31, 2025 consisted of approximately 77% natural gas and approximately 23% NGLs. We had an average working interest in our operated wells in the Barnett of approximately 96.5% as of December 31, 2025 and an Effective NRI in the Barnett of approximately 80.2%. As of December 31, 2025, our NEPA acreage position was approximately 19,100 net acres, 97% of which was held by production. Our average net daily production of 93.6 MMcfe/d for the year ended December 31, 2025 consisted entirely of natural gas. As of December 31, 2025, we had an average working interest in our operated wells in NEPA of 87.8%.

On September 29, 2025, BKV Upstream Midstream acquired 100% of the equity interests of Bedrock Production, LLC (now known as BKV Barnett II, LLC ("BKV Barnett II")), a Texas limited liability company (such transaction, the "Bedrock Acquisition"). BKV Barnett II and its subsidiaries own certain oil and natural gas producing properties and midstream assets in the Barnett Shale. As a result of the Bedrock Acquisition, we acquired approximately 96,000 net acres and gas gathering lines, 1,121 producing locations with low 1- and 5-year base decline rates of approximately 7%, and nearly 1 Tcfe of proved reserves (>70% PDP reserves) using NYMEX strip pricing. The Bedrock Acquisition is expected to increase our production over 100 MMcfe/d and enhance our inventory in the Barnett Shale, aligning with our strategic position in the Fort Worth Basin.

*Certification and Market Positioning***.** As of December 31, 2025, we re-certified approximately 72% of our NEPA production and 46% of our Barnett production under the TrustWell environmental assessment program of Project Canary, an environmental certification and ESG data company. All of our TrustWell-certified production received a Gold or Silver rating from Project Canary. Since our initial certification in 2021, the RSG market has not materialized, and during 2026, Project Canary will be closing down its TrustWell program. We may seek to certify our production against the MiQ Standard and/or align with the Oil & Gas Methane Partnership 2.0 (OGMP 2.0) of the United Nations ("UN") Environment Programme. Because there has yet to be a U.S. domestic standard for certification, we intend to position ourselves for a variety of competitive landscapes to promote market access and advance our own market for low carbon, and carbon neutral gas products by utilizing our "Carbon Sequestered Gas," which is a Scope 1, 2, and 3 carbon neutral natural gas product.

*Carbon Sequestered Gas***.** We expect that production of Carbon Sequestered Gas will be achieved by bundling our low carbon intensity produced natural gas with carbon credits sufficient to offset the estimated emissions associated with the production, gathering, and boosting of such gas, as well as the estimated emissions from its transmission, distribution (if applicable), and ultimate combustion, with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We have an agreement with a third party to establish the blockchain ledger and tokens; however, this process is dependent upon the development of the necessary technology by such third party. In addition, we expect to utilize the blockchain ledger and tokens for carbon offset produced natural gas developed by existing carbon registries such as ACR (formerly American Carbon Registry) or Verra, as those methodologies are currently being established. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects, as described below in "- *Path to Net Zero Emissions*" and retired against our Scope 1 and/or Scope 3 emissions. We believe Carbon Sequestered Gas could potentially provide a decarbonized, certified, and qualified fuel and retired credits bundle that is a differentiated and premium product.

We have a contract with Kiewit Infrastructure South Co., a subsidiary of Kiewit Corporation ("Kiewit"), for the sale and purchase of up to 100 MMBtu/d of our Carbon Sequestered Gas. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects and will be third party verified. We plan to commence delivery of Carbon Sequestered Gas upon completion of our certification process with the ACR (see "- *Carbon Capture, Utilization and Sequestration*" below).

In August 2025, BKV entered into a deal with Gunvor Group, Ltd. ("Gunvor"), a leading commodities trader for Carbon Sequestered Gas. This deal covers up to 10,000 MMBtu/d and allows Gunvor to purchase, market, and sell this premium commodity market product.

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.

Barnett

In the Barnett, during the year ended December 31, 2025, approximately 202 MMcf/d of our gross production (approximately 20% of our total gross Barnett production) was gathered and processed by our owned Barnett midstream system, which includes approximately 870 miles of gathering pipeline, 61 midstream compressors, and one amine processing unit. Our remaining Barnett production was gathered and processed primarily under an agreement with ONEOK (formerly EnLink) with no minimum volume commitments ("MVC").

For the assets we acquired in the Bedrock Acquisition, the substantial majority of our natural gas is gathered and transported by third parties, with less than 5% gathered and transported by us. 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 wholly-owned subsidiary, BKV Midstream, LLC, 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. For the assets we acquired in the Devon Barnett Acquisition, approximately 95% of our natural gas is gathered and transported by ONEOK 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 ONEOK 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.

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.

NEPA

In NEPA, we own and operate approximately 16 miles of natural gas gathering pipelines, 14 miles of freshwater distribution pipelines, and ten gas compression units in NEPA. As part of our sale of Chaffee in June 2024, we sold our minority non-operated ownership interest in a Repsol Oil & Gas operated midstream system in NEPA. Our gross operated production volumes in NEPA are contractually gathered and treated primarily by three third-party providers. For the year ended December 31, 2025, approximately 52%, 41%, and 7% of our gross operated volumes in NEPA were further gathered, treated, and transported to sales on the gathering systems of UGI Energy Services Midstream Services, Williams Companies, and Energy Transfer, 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 MVC terms, which expire in the second quarter of 2029. As of December 31, 2025, 82 MMcf/d of MVC related to the gathering, central delivery point aggregation, and intra-basin transport.

The terms of these contracts range from 10 and 20 years from original execution date, with an average term of three years remaining between the various contracts, as of December 31, 2025. 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.

Power Generation

As of December 31, 2025, we owned a 50% ownership interest in the BKV-BPP Power Joint Venture, which owns the Temple Plants, modern combined cycle gas and steam turbine power plants located in the ERCOT North Zone in Temple, Texas. As of December 31, 2025, the remaining 50% interest in the BKV-BPP Power Joint Venture was owned by BPPUS, a wholly-owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu.

Temple I and Temple II have annual average power generation capacities of 752 MW and 747 MW, respectively, and each power plant delivers power to customers on the ERCOT power network in Texas. Temple I and Temple II have baseload design heat rates of approximately 6,904 Btu/kWh and 6,950 Btu/kWh, respectively, which are below the ERCOT Combined Cycle Gas Turbines average. The modern technology utilized at the Temple Plants enables them to respond to rapidly changing market signals in real time, ensuring the highest operational readiness during the time when electricity consumption peaks (in winter and summer), making the power plants well-suited to serve the various needs of the ERCOT market. We continue to explore potential additional acquisitions to expand our power generation business. We expect our power generation assets will be synergistic with our base upstream business, and 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 February 2023, the BKV-BPP Power Joint Venture 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. As of December 31, 2025, BKV Energy has a portfolio of over 58,000 customers and is licensed to serve throughout the deregulated portions of Texas.

Following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, the BKV-BPP Power Joint Venture is owned 75% by BKV and 25% by BPPUS. Refer to *Note 14 - Investments* and *Note 19 - Subsequent Events* to our consolidated financial statements for more information.

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.

As part of our "closed-loop" approach to our net zero emissions goal, we expect to apply a portion of the CO_2 emissions that are sequestered through our CCUS business to offset GHG emissions from our owned and operated upstream and natural gas midstream businesses. We have engaged third parties to analyze and report the CO_2 injection volumes and environmental attributes of our sequestration projects, and we are working with the ACR and Verra to certify and register the environmental attributes associated with our CCUS projects as tradeable carbon credits. We expect our CCUS business to contribute in significant part to our goals to fully offset our Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses during the early 2030s, and our Scope 1, 2, and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. However, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the ability to purchase such environmental attributes BKV would not otherwise receive. We may also provide development and support services for third-party owned CCUS projects on a fee-for-service model, although such projects will not be included in our path to net zero. In addition, in the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside of our value chain. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives (and retains) or purchases. 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.

We expect to fund the majority of our CCUS business from a variety of external sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to fund the anticipated capital requirements for the potential projects that we have identified and described below through external funding and revenues from our upstream business, as well as on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. For CCUS facilities placed in service after December 31, 2022, Section 45Q of the Code generally provides the capturing parties a tax credit of $85.00 per ton for CO_2 directly stored in geologic formations, subject to satisfaction or non-application of certain prevailing wage and apprenticeship requirements (or $17.00 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. We may not receive 100% of the Section 45Q tax credits associated with projects funded by third parties and, in such cases, we will receive a certain fee for CO_2 transportation and/or sequestration services we provide for such projects, or we will receive only a corresponding percentage of the anticipated Section 45Q tax credits associated with such projects.

CCUS Projects

On May 8, 2025, BKV dCarbon Ventures, together with the Class B Member, and for the limited purposes specified therein, BKV Corporation, entered into the BKV-CIP JV Agreement forming BKV dCarbon Project, LLC (the "BKV-CIP Joint Venture") for the purpose of developing CCUS projects. On May 8, 2025, BKV dCarbon Ventures contributed to the BKV-CIP Joint Venture $40.3 million of CCUS assets that included BKV dCarbon Barnett Zero, LLC and BKV dCarbon Las Tiendas, LLC and related assets (including the Barnett Zero and Eagle Ford CCUS projects), and $4.1 million of Section 45Q accrued receivables at carrying value, and committed to future contributions of certain CCUS projects, related assets, and/or cash in exchange for an interest in the BKV-CIP Joint Venture and 4,796,421 Class A Units at $10.00 per share. The Class B Member committed up to an initial $500.0 million in cash for use by the BKV-CIP Joint Venture in construction and operating new CCUS projects across the U.S. in exchange for no more than a 49% interest in the BKV-CIP Joint Venture. As of December 31, 2025, the Class B Member contributed $17.9 million.

Currently, we have one operational CCUS project and are pursuing additional potential CCUS projects that we believe are commercially viable based on economics supported by enhanced Section 45Q tax credits and that we believe can be completed by the late 2030s. We have entered into various letters of intent and definitive contracts that we expect to grant us carbon storage and sequestration rights on over 42,000 acres of leased pore space across seven distinct projects located in three states. Our projected timeline for commercial operations of these projects depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business. Our timeline also depends on a regulatory environment that is favorable to our projects and their development. Our projects can be placed into two categories: (i) Class II (NGP) projects and (ii) Class VI projects. The table below presents actual and forecasted quantities of active sequestration operations for each category for years 2025 through 2028 and the early 2030s.

Project Category [1] [2]	YE 2025 Actual Gross Rate (Mtpy CO_2)	YE 2026 Forecasted Gross Rate (Mtpy CO_2)	YE 2027 Forecasted Gross Rate (Mtpy CO_2) [3]	YE 2028 Forecasted Gross Rate (Mtpy CO_2) [3]	Early 2030s Forecasted Gross Rate (Mtpy CO_2) [3]
Class II	0.1	0.2	0.4	1.3	2.1
Class VI	—	—	—	0.2	16.9
Total	0.1	0.2	0.4	1.5	19.0

[1] Our projected timeline for commencement of sequestration operations for the project categories identified above depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business, as well as a regulatory environment that is favorable to our projects and their development. See "*Risk Factors - Risks Related to Our CCUS Business.*"

[2] We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the ability to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives (and retains) or purchases.

[3] We have not secured external financing, reached FID, or entered into the definitive agreements necessary to execute many of the projects contributing to the YE 2027, YE 2028, and Early 2030s Forecasted Gross Rates above.

However, we have not secured external financing, reached FID, or entered into the definitive agreements necessary to execute many of the projects contributing to the YE 2027, YE 2028, and Early 2030s Forecast Gross Rates identified above, and there can be no guarantee that we will be able to execute and operate any of these potential future CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2 sequestration to achieve our Scope 1, 2, and 3 emissions goals on the timelines we anticipate. There can be no assurance that these potential CCUS projects, the projects further described herein, or any other CCUS project will achieve the forecasted sequestration volumes, and we may not commence sequestration operations for any of the projects identified above by the anticipated timeframe, or at all.

We estimate the aggregate investment required to develop the actual and potential CCUS projects identified above to be between approximately $1.3 - $1.6 billion between now and the end of 2030. We anticipate that some of these project costs will be borne by third-party investors in these projects, including our joint venture partners, owners of sources of CO_2, landowners, and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund the majority of the anticipated cost of these CCUS projects from third-party sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. 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. If sufficient external funding is not available to help fund our CCUS business, 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.

We have achieved notable milestones with respect to certain projects within each category, as more fully described below.

Class II Operational Projects

Barnett Zero Project. In November 2023, our first CCUS project, which we refer to as the Barnett Zero Project, commenced commercial sequestration of CO_2 waste generated by ONEOK's Bridgeport natural gas processing plant and neighboring operations. In the Barnett Zero Project, ONEOK transports our natural gas produced in the Barnett to its natural gas processing plant in Bridgeport, Texas, where the CO_2 waste stream is captured, compressed, and then disposed of, and sequestered via our nearby Class II injection well that complies with standards applicable to Class VI wells. During 2025, our operational projects achieved a total sequestration of approximately 138,000 metric tons of CO_2.

We have used and intend to continue to use the Barnett Zero Project as a prototype for modular NGP projects that can be repeated and quickly scaled. We are currently progressing additional NGP projects based on this model and anticipate that these projects will reach FID and initiate sequestration operations at various points in 2026 through 2028.

Class II FID Projects

Eagle Ford Project. On December 18, 2024, BKV dCarbon Ventures reached internal FID to develop our second CCUS project for the sequestration of CO_2 waste generated by a natural gas processing plant. This CCUS project, which we refer to as the Eagle Ford Project, will capture, compress, and then dispose of and geologically sequester the CO_2 waste stream generated as a byproduct of third-party natural gas processed by the plant. We estimate the Eagle Ford Project will geologically sequester up to approximately 90,000 metric tons of CO_2 per year. We currently estimate the total investment required for the Eagle Ford Project to be approximately $22 million and we expect to be entitled to use 100% of the environmental attributes associated with the project towards our net zero goals. We are targeting commencement of CO_2 sequestration activities during the first quarter of 2026, at which point we expect this project will be the second of our current modular line of identified potential NGP projects.

Cotton Cove Project. On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our third 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 midstream assets to do so. We have secured pore space for CO_2 injection, and we estimate the Cotton Cove Project will geologically sequester up to approximately 32,000 metric tons of CO_2 per year. The Cotton Cove Project is held through the BKV-BPP Cotton Cove Joint Venture, which is owned 51% by BKV dCarbon Ventures and 49% by BPPUS. We currently estimate the total investment required for the Cotton Cove Project to be approximately $18 million, of which we contributed $9.0 million and BPPUS contributed $8.8 million through December 31, 2025. We currently expect to be entitled to use the majority of the environmental attributes associated with such project towards our net zero goals. We are targeting commencement of CO_2 sequestration activities during the first half of 2026, at which point we expect this project will be the third of our current modular line of identified potential NGP projects, in addition to the Barnett Zero Project. Additionally, BKV dCarbon Ventures will manage the BKV-BPP Cotton Cove Joint Venture and leverage our existing organization to provide marketing, engineering, finance, operations, project management, accounting, and other administrative services to the BKV-BPP Cotton Cove Joint Venture, in each case for an annual fee plus expenses.

East Texas Project. On December 11, 2025, BKV dCarbon Ventures reached internal FID to develop our fourth CCUS project for the sequestration of waste emissions from a natural gas processing plant. This CCUS project, which we refer to as the East Texas Project, will capture, compress, and then dispose of and geologically sequester the CO_2 waste stream generated as a byproduct of third-party natural gas processed by the plant. We estimate the East Texas Project will geologically sequester up to approximately 70,000 metric tons of CO_2 per year. We currently estimate the total investment required for the East Texas Project to be approximately $22 million and we expect to be entitled to use 100% of the environmental attributes associated with the project towards our net zero goals. We are targeting commencement of CO_2 sequestration activities in the first half of 2027, at which point we expect this project will be the fourth of our current modular line of identified potential NGP projects.

Other Class II NGP Projects

We have identified other potential NGP projects that we anticipate will achieve FID and commence initial sequestration operations at various points in 2026 through 2028. Much of the carbon capture infrastructure required for these NGP projects is already in place. For example, the NGP facilities have amine towers to capture and concentrate CO_2 emissions to meet natural gas sales specifications. Also, we have secured or are in discussions to secure definitive agreements for pore space leasehold for several projects, and have submitted or are working towards submitting well permit applications. If these projects are approved at FID, definitive agreements are executed on the terms and timeline we believe are obtainable, and sufficient external funding is secured, we expect these projects to start sequestration operations before December 31, 2028.

On February 24, 2026, BKV dCarbon Ventures entered into a definitive agreement in connection with our fifth and sixth CCUS projects for the sequestration of waste emissions from natural gas processing plants. We expect these CCUS projects to capture, compress, and then dispose of and geologically sequester the CO_2 waste stream generated as a byproduct of Comstock Resource’s natural gas processing plants in the Western Haynesville region. Although we have not secured external financing, reached FID, or entered into all definitive agreements necessary to execute these projects we have identified, if approved at FID, assuming we are able to execute additional definitive agreements on the terms and timeline we believe are obtainable, and secure sufficient external funding, and subject to receipt of required regulatory approvals, these projects are expected to include the development of two Class II injection wells and further expand our current modular line of identified potential NGP projects. For more information about the risks involved in our CCUS business, see “*Risk Factors - Risks Related to Our CCUS Business*.”

Class VI Projects

We are also evaluating potential medium to higher concentration industrial projects to sequester third-party emissions, and anticipate these projects will achieve FID and commence initial sequestration operations at various points prior to 2033.

Pore space leaseholds have been secured for our potential industrial projects, including one covering approximately 21,000 acres of state-owned land in Louisiana, which we refer to as the High West Project.

In August 2023, High West entered into a carbon sequestration agreement with the State of Louisiana to develop facilities and permanently sequester CO_2 from local third-party emissions sources. The State of Louisiana granted High West the carbon storage and sequestration rights on approximately 21,000 acres of land in St. Charles and Jefferson Parishes. The acreage is in an ideal location for targeted carbon capture and sequestration efforts, with an estimated 10 Mtpy CO_2 of potential capture and sequestration in Phase I of the development. This site is located within a 20 mile radius from various emissions points. The Class VI permit application for Phase I of the initial five well development was submitted on March 31, 2025, and was deemed administratively complete on August 27, 2025 by the Louisiana Department of Energy and Natural Resources (now the Louisiana Department of Conservation and Energy). The storage site is estimated to have approximately 200 Mt of total CO_2 storage capacity in Phase I of the development, which is expected to support injection volumes of up to 10 Mt per year over an anticipated operating life of approximately 20 years. Additional phases of development may be undertaken as needed. We currently estimate the total investment required for High West to be approximately $163 million with the potential for additional phases of development. Under the agreement, High West will dispose of CO_2 waste from local third-party emissions sources through permanent sequestration via injection wells on the designated acreage.

We have filed applications to seek Class VI permits for three of these industrial projects, two of which are in the State of Louisiana and one of which is in the State of Texas. The U.S. Environmental Protection Agency (the "EPA") recognized our permit applications as being administratively complete in January 2024 and February 2024, respectively, for one of our State of Louisiana projects and the State of Texas project. Both the State of Louisiana and State of Texas applied for, and have been granted, primacy for the EPA's Class VI permitting program and these two applications have been transferred from the EPA to the respective state agencies. In July 2025, the Louisiana Department of Conservation and Energy additionally recognized the permit application originally submitted to the EPA for the State of Louisiana permit as administratively complete. For the other State of Louisiana Class VI location (which BKV has designated as the "High West" project), the Class VI permit application for a five well initial development industrial location was filed with the State of Louisiana on March 31, 2025. On August 27, 2025, the Louisiana Department of Conservation and Energy recognized the initial five well permit applications as being administratively complete. We continue to engage in discussions with additional CO_2 sources regarding a number of potential projects. Subject to FID for each project, the availability of sufficient external financing, and the execution of definitive agreements we believe are obtainable, we expect to initiate sequestration operations prior to 2033.

Our CCUS business and all of our CCUS projects are in the early stages of development. Although we commenced commercial operations with the initial injection of CO_2 waste at the Barnett Zero Project in November 2023, reached FID, and entered into definitive agreements with respect to the Eagle Ford Project, the Cotton Cove Project, and the East Texas Project, we have not reached FID for, or entered into the definitive agreements necessary to execute, any of the other 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 fund the anticipated capital requirements for the potential projects that we have identified through external funding and revenues from our upstream business. We expect to fund the majority of these CCUS projects from a variety of external sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. The commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. 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.*"

We are also currently progressing Front-End Engineering Design (FEED) studies regarding CO_2 capture from combined cycle natural gas power turbines, like those at our Temple location, to further delineate capital and operating costs of such facilities. Implementation of such capture at BKV's existing or developed power facilities would significantly reduce the carbon intensity of the associated power produced from such facilities.

Path to Net Zero Emissions

We conducted an initial assessment of our annual Scope 1 and 2 emissions from our owned and upstream businesses as of December 31, 2021, and subsequently updated that assessment for the upstream and natural gas midstream businesses acquired through the Exxon Barnett Acquisition in 2022 to establish an emissions baseline of 2.49 Mtpy CO_{2e} annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses as of December 31,

2021. Our assessments did not address our GHG emissions from our other business operations. Our emissions estimates presented in this Annual Report on Form 10-K are based on information with respect to our owned and operated upstream and natural gas midstream businesses in the Barnett and NEPA through fiscal year 2024 and reported by BKV pursuant to the requirements of the federal Clean Air Act GHG reporting program regulations for petroleum and natural gas systems, Subpart C and Subpart W, as applicable. These estimates will be updated annually to reflect any changes in activity, inventory, production throughput, and emissions reduction retrofits or equipment modifications, and published in our annual Sustainability Report.

Our path to net zero solely addresses GHG emissions relating to our owned and operated upstream and natural gas midstream businesses and does not address GHG emissions from our other business operations, namely our CCUS and power generation businesses. Although we believe our current path to net zero will be sufficient to reduce emissions related to our existing owned and operated upstream and natural gas midstream businesses, the future growth or expansion of such businesses will result in additional GHG emissions. We believe our approach to reducing the emissions from our owned and operated upstream and natural gas midstream operations is repeatable and scalable in connection with future growth through continued investment and expansion of our Pad of the Future program and our emissions and leak surveys, as well as additional CCUS and solar projects.

We estimate that our annual Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses were approximately 17.0 Mtpy CO_2 as of December 31, 2024. These Scope 3 emissions are currently estimated in accordance with IPIECA's "Sustainability reporting guidance for oil and gas industry," dated March 2020. Specifically, Scope 3 emissions are estimated per the Greenhouse Gas Protocol's "Corporate Value Chain (Scope 3) Accounting and Reporting Standard," released in 2011, under Category 11 (Use of Sold Product). Scope 3 emissions estimated for Category 11 represent over 90% of the Scope 3 emissions from our owned and operated upstream and natural gas midstream 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 uses 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. Effective as of 2024, the Company's Scope 3 CO_{2e} emissions are estimated using AR5 Global Warming Potentials, similar to those used by the EPA. The AR5 Global Warming Potentials supersede the AR4 Global Warming Potentials applied in prior periods. Our annual Scope 3 CO_{2e} emissions for the year ended December 31, 2024 were estimated at an approximated year-end net production volume of 855 MMcfe/d of natural gas (approximately 85% methane, 5% ethane and 10% other) and approximately 113.4 MBbls of NGLs (or approximately 1.7 MMcfe/d), as reported to the EPA for Subpart W. Our NGL constituents are estimated based on average constituent NGL barrel. Allocating the entire 856 MMcfe/d towards combustion as the end use, applying suitable combustion emission factors from the EPA, and using AR5 GWPs, Scope 3 annual emissions from our operated upstream operations are estimated at approximately 17.0 Mtpy CO_2. We currently engage third party consultants to develop and review our Scope 3 emissions estimates.

Planned Path to Net Zero (Scope 1 and 2)

Pad of the Future. Our Pad of the Future program has implemented pad level design improvements to reduce pad level usage of natural gas, reduce GHG emissions, and maintain operational continuity. As of December 31, 2025, we completed the conversion of over 75% of our pneumatic devices and pneumatic pumps in the Barnett and during the year ended December 31, 2025, we successfully completed the program with our upstream owned and operated assets in NEPA. Through December 31, 2025, our total costs incurred to complete the conversions approximated $23.6 million.

Based on the success of this effort, methane is no longer our largest source of GHG emissions on a CO_{2e} emissions-related basis. Due to this success, regulatory updates, and other operational efficiencies, we are evaluating the need for future pneumatic retrofits and will be transitioning investments to other emission reduction technologies more impactful to our assets.

Emissions Monitoring. 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.

Solar Renewable Credits. We expect to purchase the SRECs generated by the BKV-BPP Power Joint Venture's planned 2.5 MW to 5 MW solar facility. The initial 2.5 MW phase was completed and began generating power in August 2024. The BKV-BPP Power Joint Venture has obtained permits for the full 5 MW facility and is evaluating development of the remaining 2.5 MW. Solar facilities may be subject to increasingly arduous regulatory requirements, including additional permitting requirements. 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 BKV-BPP Power Joint Venture's solar facility is expected to generate SRECs sufficient to offset approximately 30% of the Scope 2 emissions from our owned and operated upstream and natural gas midstream business as of December 31, 2025.

CCUS. Further, as discussed under "— *Carbon Capture, Utilization, and Sequestration*" above, we believe that the Barnett Zero Project, together with the Eagle Ford Project, the Cotton Cove Project, the East Texas Project, and the additional pre-FID projects for the capture and sequestration of third-party emissions that we have identified, have a combined annual forecasted sequestration volume of approximately 19.0 Mtpy CO_2 during the early 2030s. Although we have not secured external financing, reached FID, or entered into the definitive agreements necessary to execute any of the additional pre-FID projects we have identified, 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, 2029.

However, we have not secured external financing, reached FID, or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above, and there can be no guarantee that we will be able to execute and operate any of the potential CCUS projects we have identified (or any other CCUS projects) with sufficient volumes of CO_2 sequestration to achieve our Scope 1, 2, and 3 emissions goals on the timelines we anticipate. There can be no assurance that any of the potential projects we have identified or the Barnett Zero Project will achieve forecasted sequestration volumes, and we may not commence sequestration operations for any of the potential projects identified above by the anticipated timeframe, or at all. Furthermore, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. In addition, in the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside our value chain. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives (and retains) or purchases. While we may consider alternatives to offset our owned and operated upstream and natural gas midstream emissions (including the purchase of verified offset credits) in order to meet our Scope 1 and 2 emissions goals, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses during the early 2030s.

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

We also aspire to offset the annual Scope 3 emissions impact of our owned and operated upstream and natural gas midstream businesses by the late 2030s, which we estimated to be approximately 17.0 Mtpy CO_2 annually as of December 31, 2024. Our CCUS business of capturing and sequestering our gas processing-related emissions along with third-party GHG 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 and natural gas midstream businesses by the late 2030s is primarily limited to our Category 11 (Use of Sold Product) emissions, which we believe represents a significant portion of the overall Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses. We will periodically perform materiality assessments on our Scope 3 emissions to ensure the accuracy of our Scope 3 missions footprint. At this time, our Scope 3 emissions estimate does not include our GHG emissions from our other business operations, namely our CCUS and power generation businesses.

As discussed in "— *Carbon Capture, Utilization and Sequestration*," above, we are currently operating the Barnett Zero Project owned by the BKV-CIP Joint Venture and have identified additional potential CCUS projects that we believe are commercially viable and estimate would have a combined forecasted annual volume of carbon capture and sequestration of approximately 19.0 Mtpy CO_2 during the early 2030s, which represents a majority of our current Scope 1, 2, and 3 annual emissions from our owned and operated upstream and natural gas midstream businesses. The BKV-CIP Joint Venture will retain and monetize all environmental attributes associated with CCUS projects contributed to the BKV-CIP Joint Venture, including pursuant to a first right of BKV or its affiliates to purchase such environmental attributes at fair market value. Ultimately, with respect to CCUS projects contributed to the BKV-CIP Joint Venture, we will be able to apply to offset our own GHG emissions only the portion of sequestered emissions attributable to the percentage of environmental attributes that BKV purchases from the BKV-CIP Joint Venture. We will continue to evaluate and identify potential CCUS project opportunities consistent with our goal of offsetting our annual Scope 1, 2, and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. However, we may not purchase, receive, or retain 100% of the environmental attributes associated with our CCUS projects as discussed above, which may negatively impact our net zero strategy, potentially delaying or preventing our progress towards achieving our net zero goals.

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 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. If sufficient external funding is not available to help fund our CCUS business, 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 and natural gas midstream businesses by the late 2030s.

Our Acreage

The following table summarizes our acreage position as of December 31, 2025:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett [1]	760,746	504,815	48,330	39,214	809,076	544,029
NEPA	21,677	18,312	1,467	785	23,144	19,097
Total	782,423	523,127	49,797	39,999	832,220	563,126

The following table summarizes our acreage position as of December 31, 2024:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett [1]	641,923	426,314	40,134	35,496	682,057	461,810
NEPA	21,677	18,312	1,467	785	23,144	19,097
Total	663,600	444,626	41,601	36,281	705,201	480,907

The following table summarizes our acreage position as of December 31, 2023:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett [1]	638,193	421,491	41,113	38,421	679,306	459,912
NEPA	63,739	29,501	18,774	7,364	82,513	36,865
Total	701,932	450,992	59,887	45,785	761,819	496,777

[1] Includes acreage acquired during 2021 from Jamestown Resources, LLC, Larchmont Resources, LLC, and Pelican Energy, LLC, for which acreage the leasehold interest is derived from unit-based assignments and includes 133,470 gross and 3,318 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 0.93% in 2026, 1.14% in 2027, and 0.64% in 2028.

Our Productive Wells

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2025:

Operated Wells	Producing Natural Gas Wells Gross	Producing Natural Gas Wells Net	Producing Oil Wells Gross	Producing Oil Wells Net	Total Gross	Total Net	Average Working Interest
Barnett	6,357	6,132	10	10	6,367	6,142	96.5 %
NEPA	147	129	—	—	147	129	87.8 %
Total	6,504	6,261	10	10	6,514	6,271	96.3 %
Non-Operated Wells							
Barnett	927	89	7	1	934	90	9.6 %
NEPA	36	1	—	—	36	1	2.8 %
Total	963	90	7	1	970	91	9.4 %
Total							
Barnett	7,284	6,221	17	11	7,301	6,232	85.4 %
NEPA	183	130	—	—	183	130	71.0 %
Total	7,467	6,351	17	11	7,484	6,362	85.0 %

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2024:

Operated Wells	Producing Natural Gas Wells Gross	Producing Natural Gas Wells Net	Producing Oil Wells Gross	Producing Oil Wells Net	Total Gross	Total Net	Average Working Interest
Barnett	5,492	5,340	7	7	5,499	5,347	97.2 %
NEPA	142	130	—	—	142	130	91.5 %
Total	5,634	5,470	7	7	5,641	5,477	97.1 %
Non-Operated Wells							
Barnett	924	90	1	—	925	90	9.7 %
NEPA	35	—	—	—	35	—	— %
Total	959	90	1	—	960	90	9.4 %
Total							
Barnett	6,416	5,430	8	7	6,424	5,437	84.6 %
NEPA	177	130	—	—	177	130	73.4 %
Total	6,593	5,560	8	7	6,601	5,567	84.3 %

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2023:

Operated Wells	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Barnett	5,614	5,437	6	6	5,620	5,443	96.9 %
NEPA	142	127	—	—	142	127	89.4 %
Total	5,756	5,564	6	6	5,762	5,570	96.7 %
Non-Operated Wells							
Barnett	993	95	1	—	994	95	9.6 %
NEPA	272	37	—	—	272	37	13.6 %
Total	1,265	132	1	—	1,266	132	10.4 %
Total							
Barnett	6,607	5,532	7	6	6,614	5,538	83.7 %
NEPA	414	164	—	—	414	164	39.6 %
Total	7,021	5,696	7	6	7,028	5,702	81.1 %

Drilling, Refrac, and Restimulation Activity

During the years ended December 31, 2025, 2024, and 2023, we drilled development wells as set forth in the table below:

Development	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Barnett						
Productive	33.0	33.0	6.0	6.0	15.0	15.0
Dry	1.0	0.9	—	—	—	—
NEPA						
Productive	4.0	4.0	—	—	3.0	3.0
Dry	—	—	—	—	—	—
Total	38.0	37.9	6.0	6.0	18.0	18.0

As of December 31, 2025, we had four wells (4.0 net) drilled and uncompleted in the Barnett and three wells (3.0 net) drilled and uncompleted in NEPA. In addition, we had one well (1.0 net) in the process of being drilled in the Barnett, and none in NEPA. During the year ended December 31, 2025, 35 wells (34.9 net) were completed in the Barnett, which included two previously drilled but uncompleted wells that were acquired in the Bedrock Acquisition, and one well was completed in NEPA, all of which were net productive. All drilled and uncompleted wells from prior year programs had been completed and placed into production as of December 31, 2025.

As of December 31, 2024, we had four wells (4.0 net) drilled and uncompleted in the Barnett and no wells drilled and uncompleted in NEPA. During the year ended December 31, 2024, ten wells were completed in the Barnett and three wells were completed in NEPA, all of which were net productive. All drilled and uncompleted wells from prior year programs had been completed and placed into production as of December 31, 2024.

During the year ended December 31, 2023, seven wells were completed in the Barnett (all of which were net productive) and no wells were completed in NEPA.

We also maintain a restimulation program in the Barnett to develop economic incremental reserves in existing wellbores and arrest the overall field production decline. During the years ended December 31, 2025, 2024, and 2023, we completed 56, three, and 32 horizontal and vertical restimulations, respectively. Additionally, as of December 31, 2025, we had 209 proved undeveloped horizontal locations and 323 proved developed non-producing refrac candidates in the Barnett. For a discussion of how we identify drilling locations and refrac candidates, please see "— D*etermination of Identified Drilling and Refracture Locations*."

Production Volumes and Average 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, 2025, 2024, and 2023.

	Year ended December 31,		
	2025	2024	2023
Production Volumes			
Barnett			
Natural gas (MMcf)	208,779.7	185,857.3	198,099.4
Natural gas liquids (MBbl)	10,181.4	9,857.7	10,553.6
Oil (MBbl)	159.3	96.0	118.6
Total Barnett (Bcfe)	270.8	245.6	262.1
NEPA			
Natural gas (MMcf)	34,151.7	42,825.3	51,666.9
Natural gas liquids (MBbl)	—	—	—
Oil (MBbl)	—	—	—
Total NEPA (Bcfe)	34.2	42.8	51.7
Total Company (Bcfe)	305.0	288.4	313.8
Average Sales Prices (excluding impact of derivative settlements)			
Barnett			
Natural gas ($/Mcf)	$ 2.91	$ 1.87	$ 2.28
Natural gas liquids ($/Bbl)	$ 17.00	$ 16.79	$ 17.80
Oil ($/Bbl)	$ 59.38	$ 68.81	$ 71.21
NEPA			
Natural gas ($/Mcf)	$ 1.98	$ 0.91	$ 1.12
Natural gas liquids ($/Bbl)	$ —	$ —	$ —
Oil ($/Bbl)	$ —	$ —	$ —
Total Company ($/Mcfe)	$ 2.81	$ 1.93	$ 2.25
Average Sales Prices (including the impact of derivative prices) [1]			
Natural gas ($/Mcf)	$ 2.75	$ 2.10	$ 2.23
Natural gas liquids ($/Bbl)	$ 16.84	$ 17.19	$ 17.55
Oil ($/Bbl)	$ 59.50	$ 68.81	$ 70.97
Total Company ($/Mcfe)	$ 2.79	$ 2.28	$ 2.39
Average Production Cost ($/Mcfe) [2]			
Barnett	$ 1.45	$ 1.43	$ 1.48
NEPA	$ 0.29	$ 0.20	$ 0.24
Total Company	$ 1.32	$ 1.25	$ 1.27

[1] Impact of derivative prices excludes $13.3 million and $46.7 million of gains on derivative contract terminations for the years ended December 31, 2024 and 2023, respectively.

[2] Excludes natural gas and oil ad valorem and production taxes.

For additional information on pricing see, *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Item 7 of Part II in this Annual Report on Form 10-K.

Determination of Identified Drilling and Refracture Locations

Proved Drilling and Refracture Locations

As of December 31, 2025, we had approximately 209 gross (191 net) proved undeveloped horizontal drilling locations and 323 gross (305 net) proved developed non-producing refrac candidates at SEC reserves pricing. We use production data and experience gains from our development programs to identify and prioritize development of our proved inventory of undeveloped horizontal drilling locations and proved developed non-producing refrac candidates. These drilling locations and refrac candidates are included in our proved inventory only after they have been evaluated technically and are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years. As a result of technical evaluation of geologic and engineering data, it can be estimated with reasonable certainty that reserves from these locations are commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations, and other factors it deems relevant in determining such locations.

Unproved Drilling and Refracture Locations

Our unproved horizontal drilling locations and refrac candidates are specifically identified on a field-by-field basis considering the applicable geologic, engineering, and production data. We analyze past field development practices and identify analogous drilling opportunities taking into consideration historical production performance, estimated drilling and completion costs, spacing, and other performance factors. These horizontal drilling locations and refrac candidates primarily include (i) infill drilling locations, (ii) additional locations due to field extensions, and (iii) restimulations. We believe the assumptions and data used to estimate these horizontal drilling locations and refrac candidates are consistent with established industry practices based on the type of recovery processes we are using.

Summary of Our Reserves Estimates

Ryder Scott, our independent petroleum engineers, prepared estimates of our natural gas, NGL, and oil reserves as of December 31, 2025, 2024, and 2023. These reserves estimates were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserves reporting. For more information about our reserves volumes and values, see "— *Preparation of Reserves Estimates and Internal Controls*" and Ryder Scott's summary reserve reports, which are filed as exhibits to this Annual Report on Form 10-K.

The following table provides our estimated proved reserves information prepared by Ryder Scott as of December 31, 2025, 2024, and 2023 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, 2025, as compared to December 31, 2024, is primarily due to higher commodity pricing. The decrease in our proved reserves and the PV-10 Value of those reserves as of December 31, 2024, as compared to December 31, 2023, was primarily due to lower commodity pricing. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL, and oil reserves and their values, including many factors beyond our control.

Estimated SEC Reserves [1]

	December 31,		
	2025	2024	2023
Estimated proved developed reserves:			
Natural gas (MMcf)	3,097,864	2,059,984	2,443,072
Producing	2,913,523	1,951,322	2,290,025
Non-producing	184,341	108,662	153,047
Natural gas liquids (MBbls)	183,111	134,017	156,399
Producing	162,684	113,739	129,260
Non-producing	20,427	20,278	27,139
Oil (MBbls)	1,763	878	992
Producing	1,600	713	802
Non-producing	163	165	190
Total estimated proved developed reserves (MMcfe)	4,207,108	2,869,354	3,387,418
Producing	3,899,227	2,638,034	3,070,397
Non-producing	307,881	231,320	317,021
Estimated proved undeveloped reserves:			
Natural gas (MMcf)	1,247,900	176,047	539,423
Natural gas liquids (MBbls)	75,545	13,605	27,766
Oil (MBbls)	2,118	813	59
Total estimated proved undeveloped reserves (MMcfe) [2], [3]	1,713,878	262,555	706,373
Estimated total proved reserves:			
Natural gas (MMcf)	4,345,764	2,236,031	2,982,495
Natural gas liquids (MBbls)	258,656	147,622	184,165
Oil (MBbls)	3,881	1,691	1,051
Total estimated proved reserves (MMcfe)	5,920,986	3,131,909	4,093,791
Standardized Measure (millions)	$ 2,345	$ 633	$ 1,062
PV-10 (millions) [4], [5]	$ 2,788	$ 672	$ 1,232

[(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, 2025 were $3.39 per MMBtu (Henry Hub), $65.34 per Bbl (WTI Cushing), and NGL pricing equal to 34.4% of WTI Cushing, (ii) at December 31, 2024 were $2.13 per MMBtu (Henry Hub), $75.48 per Bbl (WTI Cushing), and NGL pricing equal to 29.5% of WTI Cushing, and (iii) at December 31, 2023 were $2.637 per MMBtu (Henry Hub), $78.22 per Bbl (WTI Cushing), and NGL pricing equal to 29.5% of WTI Cushing.

[(2)] Proved undeveloped reserves as of December 31, 2025, 2024, and 2023 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 proved undeveloped reserves, which may cause us to decrease the amount of our proved undeveloped reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our proved undeveloped reserves to become uneconomic to develop, which would cause us to remove them from their respective reserves category.

[(4)] 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.

[(5)] The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved reserves as of December 31, 2025, 2024, and 2023:

	December 31,		
	2025	2024	2023
PV-10 (millions)	$ 2,788	$ 672	$ 1,232
Present value of future income taxes discounted at 10%	(443)	(39)	(170)
Standardized Measure	$ 2,345	$ 633	$ 1,062

During the years ended December 31, 2025, 2024, and 2023, we incurred costs of approximately $140.0 million, $22.8 million, and $37.7 million, respectively, to convert 157.9 Bcfe, 57.6 Bcfe, and 31.9 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, 2025, 2024, and 2023, were approximately $1.0 billion, $135.1 million, and $360.7 million, respectively, over the next five years, substantially all of which we expect to finance through cash flow from operations and/or borrowings under our RBL Credit Agreement. Our development programs during the year ended December 31, 2025 focused on refracturing under-stimulated wells and designing and drilling new wells in the Barnett, and designing, completing, and drilling new wells in NEPA. Our proved undeveloped reserves, as of December 31, 2025, are scheduled to be developed within five years of their initial disclosure.

2025 Activity

During the year ended December 31, 2025, our proved reserves increased by 2,789.1 Bcfe. The increase in proved reserves was primarily attributable to increased commodity pricing and drilling activity, which resulted in total upward revisions of 2,201.0 Bcfe. In addition, in September 2025, we acquired 100% of the equity interests of BKV Barnett II (formerly known as Bedrock Production, LLC), increasing reserves by 743.0 Bcfe. Our extensions and discoveries and improved recoveries experienced in 2025 also resulted in net increases to proved reserves of 129.6 Bcfe and 20.6 Bcfe, respectively. We produced 305.0 Bcfe during the year ended December 31, 2025.

Revisions of previous estimates primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 915.8 Bcfe and 679.2 Bcfe, respectively, as a result of higher average pricing during 2025 for natural gas, NGLs, and oil. Additional upward revisions were made to proved undeveloped reserves of 599.2 Bcfe due to increases in capital spend and drilling activity during 2025. Changes to the Company's drilling schedule added 86.0 gross (81.2 net) proved locations in NEPA and the Barnett to be developed within the next five years. The drilling schedule changes reflect the Company's ongoing commitment to optimize the long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries added 129.6 Bcfe of proved undeveloped reserves across 11.0 gross (8.9 net) locations, driven by our optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2025.

Improved recoveries added 20.6 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2025.

Purchases of minerals in place consisted of 494.6 Bcfe and 248.4 Bcfe of acquired proved developed reserves and proved undeveloped reserves, respectively, from the Bedrock Acquisition, which represented 1,002.0 gross (877.6 net) locations in the Barnett.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 211.8 Bcfe related to the completion of 34.0 gross (31.0 net) wells during the year ended December 31, 2025 that were converted to proved developed wells, previously classified as proved undeveloped.

2024 Activity

During the year ended December 31, 2024, our proved reserves decreased by 961.9 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in our planned drilling activity, which resulted in total downward revisions of 714.9 Bcfe. In addition, in June 2024, we sold our wholly-owned subsidiary, Chaffee and certain of our non-operated upstream assets in Chelsea, decreasing reserves by 150.0 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries we experienced in 2024, which resulted in net increases to proved reserves of 139.2 Bcfe and 52.2 Bcfe, respectively. We produced 288.4 Bcfe during the year ended December 31, 2024.

Revisions of previous estimates primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 235.6 Bcfe and 213.7 Bcfe, respectively, as a result of lower average pricing during 2024 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 265.6 Bcfe due to lower capital spend and the resulting reduction in drilling activity during 2024. Changes to our drilling schedule moved the development of 38.0 gross (35.1 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUD reserves five years from initial booking. These 38.0 gross (35.1 net) locations remain in inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect our ongoing commitment to optimize the long-term plan to best develop our assets, maximize cash flow, and produce economic returns.

Extensions and discoveries added 139.2 Bcfe of proved undeveloped reserves across 16.0 gross (14.4 net) locations, driven by our optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2024.

Improved recoveries added 52.2 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2024.

Sale of minerals in place consisted of 103.9 Bcfe and 46.1 Bcfe of divested proved developed reserves and proved undeveloped reserves, respectively, of Chaffee assets and certain non-operating upstream assets in Chelsea, both sold in June 2024, which represented 330.0 gross (39.6 net) locations in NEPA.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 57.6 Bcfe related to the completion of 8.0 gross (7.9 net) wells during the year ended December 31, 2024 that were converted to proved developed wells, previously classified as proved undeveloped.

2023 Activity

During the year ended December 31, 2023, our proved reserves decreased by 2,042.1 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in our drilling activity, which resulted in total downward revisions of 1,986.3 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries in 2023, which resulted in net increases to proved reserves of 227.8 Bcfe and 30.2 Bcfe, respectively. We produced 313.8 Bcfe during the year ended December 31, 2023.

Revisions of previous estimates primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 1,191.9 Bcfe and 273.1 Bcfe, respectively, as a result of lower average pricing during 2023 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 521.3 Bcfe due to lower capital spend and the resulting reduction in drilling activity during 2023. Changes to our drilling schedule moved the development of 112.0 gross (104.8 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUD reserves five years from initial booking. These 112.0 gross (104.8 net) locations remain in inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect our ongoing commitment to optimize the long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries primarily consisted of 226.5 Bcfe of proved undeveloped reserves, of which 197.8 Bcfe was attributable to 22.0 gross (21.2 net) locations recognized as a result of our optimized drilling program, which reduced costs and extended lateral lengths. In addition, 28.7 Bcfe was attributable to extensions related to 3.0 gross (1.1 net) locations in NEPA. Our unitization and combination of acreage with Repsol resulted in the three additional locations.

Improved recoveries consisted of 30.2 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, 2023.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 31.9 Bcfe related to the completion of 22.0 gross (8.1 net) wells during the year ended December 31, 2023 that were converted to proved developed wells, previously classified as proved undeveloped.

Estimated Reserves at NYMEX Strip Pricing

The following table provides our total estimated proved reserves information prepared by Ryder Scott as of December 31, 2025, using NYMEX strip prices as of market close on December 31, 2025 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, 2025. The historical 12-month pricing average in our December 31, 2025 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, 2025. 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. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL, and oil reserves quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserves estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.*"

	December 31, 2025
Estimated proved developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	3,156,787
Producing	2,972,440
Non-producing	184,347
Natural gas liquids (MBbls)	183,504
Producing	163,078
Non-producing	20,426
Oil (MBbls)	1,760
Producing	1,597
Non-producing	163
Total estimated proved developed reserves (MMcfe)	4,268,371
Producing	3,960,490
Non-producing	307,881
Estimated proved undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	1,243,920
Natural gas liquids (MBbls)	74,843
Oil (MBbls)	2,086
Total estimated proved undeveloped reserves (MMcfe) [1], [2]	1,705,494
Estimated total proved reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	4,400,707
Natural gas liquids (MBbls)	258,347
Oil (MBbls)	3,846
Total estimated proved reserves (MMcfe)	5,973,865
Standardized Measure (millions)	$ 2,574
PV-10 (millions) [3]	$ 3,082

[1] Proved undeveloped reserves December 31, 2025 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

[2] Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our proved undeveloped reserves, which may cause us to decrease the amount of our proved undeveloped reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our proved undeveloped reserves to become uneconomic to develop, which would cause us to remove them from their respective reserves category.

[3] 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, 2025:

	December 31, 2025
PV-10 (millions)	$ 3,082
Present value of future income taxes discounted at 10%	(508)
Standardized Measure	$ 2,574

Preparation of Reserves Estimates and Internal Controls

Our reserves estimates as of December 31, 2025, 2024, and 2023 included in this Annual Report on Form 10-K are based on reports prepared by Ryder Scott, our independent reserves 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 reserves 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)." A copy of Ryder Scott's reserve reports are included as exhibits to this Annual Report on Form 10-K.

Prior to our annual reserves process, our internal staff of petroleum engineers, geoscience professionals, operations, land, finance and accounting, and marketing personnel work closely together to ensure the integrity, accuracy, and timeliness of our reserves data. Our reservoir engineering team then reviews such data and provides it to, and works closely with, our independent reserves engineers as part of their reserves 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 reserves engineers to review properties and discuss methods and assumptions used to prepare reserves estimates. Our Chief Corporate Development Officer, Ethan Ngo, is primarily responsible for overseeing the independent reserves engineers during the process. Mr. Ngo has over 17 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 reserves estimates, including such items as 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. The internal reservoir engineering team reports directly to our President of Upstream. Management is responsible for establishing internal controls used in the preparation of our oil and gas reserves, which include verification of data input into reserves forecasting and economics evaluation software and multi-discipline management reviews performed by the corporate reserves team.

Enterprise Risk Management

We have a standing risk management committee (“RMC”), which meets regularly and assesses, mitigates, and provides direction on management of key enterprise risks. Our enterprise risk management function is overseen by the Senior Director of Risk Management, who coordinates our risk assessment and monitoring processes and reports to executive leadership. The RMC is comprised of executives and senior leaders across various functions, including legal, information technology, marketing, regulatory and sustainability, safety, security, operations, finance and accounting, and land.

Customers and Product Marketing

We utilize an unaffiliated third party to market all of our natural gas production to various purchasers, which consist of creditworthy counterparties, including utilities, LNG producers, industrial consumers, major corporations, and super majors in our industry. We rely on the creditworthiness 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. 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). We will periodically enter into longer-term commitments with downstream pipelines for firm transportation service. As of December 31, 2025, we have multiple contracts for firm transportation services including a combined 61,000 MMBtu/d to various locations on Tennessee Gas Pipeline and 27,500 MMBtu/d on Millennium 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 a few months to 10 years, with an average remaining duration of 3.6 years as of December 31, 2025.

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 175,000 MMBtu/d of interstate transport to Transco Zone 4 Station 85, and 60,000 MMBtu/d to NGPL-TxOk with term end dates ranging through 2026 and 2029. We are currently negotiating extensions of several Barnett transportation agreements to preserve optionality to transport volumes out of the Barnett.

We were assigned 205,716 MMBtu/d of firm transport on Energy Transfer and Houston Pipe Line Company LP ("Houston Pipe Line"), which expires in 2027. We also received two firm transport contracts with these same shippers from the Bedrock Acquisition for 23,750 MMBtu/d each, both subject to yearly volume reductions that expire in 2028. These contracts with Energy Transfer and Houston Pipe Line provide access to the NGPL-TxOk market.

As it relates to the Temple Plants, in addition to 2,812,500 MMBtu of storage at Energy Transfer’s Bammel storage facility which expires in December 2027, the Temple Plants hold a combined 200,000 MMBtu/d of firm transport with Atmos and Energy Transfer and its subsidiaries which supports receipt of gas from the Katy Area with delivery to the Temple Facility and expires in December 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. As of December 31, 2025, our minimum aggregate required payments per year under firm gathering and transportation agreements were $70.2 million for 2026, $62.1 million for 2027, $53.9 million for 2028, $34.3 million for 2029, $5.9 million for 2030, and $33.0 million for 2031 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 of our transport contracts for NEPA, the Barnett, and the Temple Plants are at competitive rates.

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 may also have detrimental effects on available supply.

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.

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 our competitors not only engage in the acquisition, exploration, development, and production of oil and gas reserves and electricity generation, but also in 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. Occasionally, such materials, equipment, and labor may be in short supply. 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, inflation may affect us more than it may affect some of our larger competitors.

Ownership by our Directors and Officers in Other Entities

Most of our non-independent directors now own, or our officers and other directors may own in the future, stock and options to purchase stock in one or more of Banpu or its related companies. In addition, certain of our directors or officers may own disproportionate interests (in percentage or value terms) in Banpu or its related companies. These ownership interests and/or such disparity could create, or appear to create, potential conflicts of interest when the applicable individuals are faced with decisions that could have different implications for us, Banpu, or its related companies.

Human Capital Resources

As of December 31, 2025, we had a total of 452 employees. We hire independent contractors on an as-needed basis. 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 meetings 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 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 in 2024 and again in late-2025 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, which 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 various financial, health, and/or wellness programs. We also offer 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.

We have a whistleblower policy supported by a confidential ethics and compliance hotline (available via call-in or an online submission portal) and a required manager and employee online training program that includes topics such as business ethics, human rights and diversity, equity, and inclusion. Completion of this training is tracked on a quarterly basis to ensure accountability.

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 to ensure alignment with the dynamic rights of our workforce. Our Human Rights Policy extends to all our operations, as well as partners, contractors, 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 the disposal or other disposition of produced water;

- 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-up obligations, 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, 2025 we have recorded asset retirement obligations of $233.3 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 management or possible release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, have the potential to be sources of CERCLA liability, 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, including Texas, also have environmental cleanup laws analogous to CERCLA.

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 exemption from regulation as hazardous waste under 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 non-exploration and production industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics or are listed as hazardous under RCRA.

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 Clean Water Act, or 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 promulgated wastewater pretreatment standards that 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. For additional information, see “*Risk Factors - Risks Related to Environmental, Legal Compliance and Regulatory Matters - We may face unanticipated water and other waste disposal costs as a result of increased water-related regulations*.”

Safe Drinking Water Act. The Safe Drinking Water Act, or 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 and other injection 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 the procurement of 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, the 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 or state 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.

Additionally, the EPA has established the Class VI well classification under the SDWA UIC for wells used for long-term geologic sequestration of CO_2. We will be required to obtain a Class VI permit for our CCUS projects that do not meet the criteria for Class II oil and gas related acid gas injection wells. The Class VI UIC permit program is currently administered by the EPA in all states except for Louisiana, Texas, Wyoming, North Dakota, West Virginia, and Arizona, which have assumed primacy for Class VI permitting. Class VI permits currently require a lengthy permitting process, and the costs and regulatory burdens associated with obtaining Class VI permits could delay development of our CCUS projects.

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 rules requiring the disclosure of chemicals used in hydraulic fracturing fluids, 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 (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) 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, former 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. More recently, on March 8, 2024, the EPA published its Methane Rule, which took effect on May 7, 2024 and established requirements for methane emissions from existing and modified oil and gas sources and imposed additional requirements for new sources with respect to methane and volatile organic chemical emissions, including sources not previously regulated under the oil and gas source category. In late 2025, the EPA issued final rules extending certain compliance deadlines in the Methane Rule and the NSPS rules for the oil and gas sector. It remains to be seen what impact the Trump Administration ultimately will have on these and other climate-related measures taken under the Biden Administration. 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.

Collectively, these rulemaking actions, 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, in the past 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, commonly known as the "Endangerment Finding," which underpins the EPA's regulation of greenhouse gas emissions. On February 18, 2026, the EPA published a final rule rescinding the Endangerment Finding. The rescission has been challenged in court, which could result in the rescission being stayed, overturned or limited in scope or effect. If the rescission remains in effect, the EPA may seek in the future to repeal or lessen the stringency of regulations affecting the oil and natural gas industry that are based, at least in part, on the Endangerment Finding. Further, it is possible that efforts to regulate GHGs at the national level in the United States, which could include reconsidering the Endangerment Finding, could occur in the future. The ultimate outcome and long-term effect of the rescission of the Endangerment Finding, as well as its impact on regulation of the oil and natural gas industry, remains uncertain.

The EPA 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. On September 12, 2025, the EPA issued a proposed rule that would rescind the GHG reporting rule, other than for natural gas systems subject to waste emission charges, and would delay requirement or these systems until 2034. It remains to be seen what the ultimate outcome of this proposal will be and what the ultimate impact and long-term effect the Trump Administration rollback initiatives will have on this and other climate-related measures taken under the Biden Administration. 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. The United States officially rejoined the Paris Agreement on February 19, 2021, and in April 2021 submitted its NDC, which set an economy-wide target of net GHG emissions reduction from 2005 levels of 50-52% by 2030. However, effective on January 26, 2026, the Trump Administration again formally exited the Paris Agreement. It remains to be seen what the long-term effect of this action will be.

The United States Congress ("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 Jumpstart Our Business Startups Act of 2012 (the "JOBS Act") 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 imposed several new climate-related requirements on oil and gas operations and the Inflation Reduction Act of 2022 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, if and when they take effect, 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. The Trump Administration has delayed or rolled back most of the climate-related measures taken under the Biden administration, but it is possible that future administrations could again pursue these or other climate-related initiatives.

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 U.S. state governors 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. In addition, California enacted two new climate disclosure laws in September 2023 that (1) require U.S.-based businesses with total annual revenues over one billion dollars and doing business in California to annually report their Scope 1, 2, and 3 GHG emissions, and (2) require U.S.-based businesses with total annual revenues over five hundred million dollars and doing business in California to prepare biennial risk reports disclosing the entity's climate-related financial risk and measures adopted to reduce and adapt to climate-related financial risk. Litigation challenging the California climate disclosure laws is ongoing. Although reporting under both laws was slated to commence in 2026, on November 18, 2025, the U.S. Court of Appeals for the Ninth Circuit issued an injunction prohibiting enforcement of the climate-related financial risk disclosure law pending its consideration of a First Amendment challenge to the law. The California Air Resources Board has issued guidance on compliance with the disclosure laws and is in the process of developing regulations to implement the California climate-related disclosure requirements. Furthermore, if the SEC's climate disclosure requirements remain in place and are ultimately enforced by the SEC or if similar requirements are put in place in the future, we will be required to incur significant time and money to comply with the disclosure requirements and may be required to modify certain of our operations. These compliance costs could adversely impact our future business.

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 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 Endangered Species Act, or 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.

Environmental Justice Considerations. Attention to environmental justice considerations — from activist groups and/or government regulators — may impede or otherwise have an adverse effect on our ability to develop both our fossil fuel assets and our proposed CCUS projects. For example, the Biden Administration created a White House Office of Environmental Justice in April 2023, and all federal agencies were directed to make environmental justice a central part of each agency's mission by publishing an environmental justice strategic plan for the agency. Although this office no longer exists and environmental justice considerations are not a focus of the Trump Administration, a future administration could change course and, if so, the development and application of environmental justice requirements may result in permit uncertainty and delays for our activities that require federal approvals.

Operating Hazards and Insurance

Natural gas and NGL 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. 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.

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.

Address, Internet Website, and Availability of Public Filings

Our principal executive offices are located at 1200 17th Street, Suite 2100, Denver, Colorado 80202, and our telephone number is (720) 375-9680. We also maintain an offices in Fort Worth, Texas as well as several regional field offices. Our website is *www.bkv.com*.

We furnish or file our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K, and amendments to such reports and other documents with the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The SEC also maintains an internet website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC. We also make these documents available free of charge at *www.bkv.com* under the “Investors” link as soon as reasonably practicable after they are filed or furnished with the SEC. Our Sustainability Report is also available on our website.

Information on our website is not incorporated into this Annual Report on Form 10-K or our other filings with the SEC and is not a part of them.

Information about our Executive Officers (as of March 6, 2026)

Name	Age	Current Title (Year Initially Elected an Executive Officer)
Christopher P. Kalnin	48	Chief Executive Officer (2020)
David R. Tameron	58	Chief Financial Officer (2025)
Eric S. Jacobsen	55	President — Upstream (2020)
Barry S. Turcotte	55	Chief Accounting Officer (2022)
Lindsay B. Larrick	43	Chief Legal and Chief Administrative Officer (2022)
Ethan Ngo	44	Chief Corporate Development Officer (2022)
Dilanka Seimon	45	Chief Commercial Officer (2025)

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. In September 2023, he was appointed as a member of a newly established Executive Committee of Banpu, with the delegation of authority to manage all aspects of Banpu’s businesses in North America, among other things, and has served as a member of the board of managers of the BKV-BPP Power Joint Venture since October 2021. He also worked at Kalnin Ventures, the fund manager of BKV Oil and Gas Capital Partners, L.P., 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., 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 an HBA 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.

David R. Tameron has served as Chief Financial Officer of the Company since April 2025. Mr. Tameron previously served as the Company's Vice President, Strategic Finance and Investor Relations from August 2022 to March 2025. Prior to joining BKV in August 2022, Mr. Tameron served in various roles at Wells Fargo & Company, including as Managing Director of Denver-based Corporate Banking, from September 2017 to August 2022, and as Managing Director, Institutional Equity Research, from July 2006 to August 2017. Mr. Tameron earned an MBA from the Fuqua School of Business at Duke University and a BA in Finance from Arizona State University.

Eric S. Jacobsen has served as President — Upstream of the Company since February 2025 and as a member of the board of managers of the BKV-BPP Power Joint Venture since March 2025. Mr. Jacobsen previously served as Chief Operating Officer of the Company from its formation in May 2020 to February 2025. 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.

Lindsay B. Larrick has served as Chief Administrative Officer of the Company since February 2025 and as Chief Legal Officer of the Company since July 2022. She has also served as a member of the board of managers of the BKV-BPP Power Joint Venture since February 2025. Ms. Larrick previously served as Vice President, General Counsel and Corporate Secretary of the Company from its formation in May 2020 to July 2022, and 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 Corporate Development Officer of the Company since February 2025 and as a member of the board of managers of the BKV-BPP Power Joint Venture since June 2024. Mr. Ngo previously served as Chief Technical Resources Officer of the Company from July 2022 to February 2025 and, prior to that, as Senior Vice President, Engineering of the Company from its formation in May 2020 to July 2022. 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.

Dilanka Seimon has served as Chief Commercial Officer of the Company since April 2025. Prior to joining the Company, Mr. Seimon served as Executive Vice President and Chief Commercial Officer at EnLink Midstream (now, ONEOK) from August 2023 to February 2025, and as Vice President of Alternative Energy at Energy Transfer (NYSE: ET), from January 2022 to August 2023. From March 2013 through December 2021, Mr. Seimon served at BHP Group Limited (NYSE: BHP), the world's largest mining company by market capitalization, working his way up to Vice President of Sales and Marketing. Earlier in his career, he held various roles in business development, natural gas trading, marketing, and origination. Mr. Seimon completed the General Management Program at Harvard Business School, earned an MBA from the Fuqua School of Business at Duke University, and received a BS in Economics from Georgia College & State University.

ITEM 1A. RISK FACTORS

The following risk factors should be considered in evaluating our business and future prospects, in addition to other information included in this Annual Report on Form 10-K. Additional risk factors not presently known to us, or currently considered immaterial, may also have an adverse impact on our business, financial condition, and results of operations. If any of the events described below occur, our business, financial condition, or results from operations may suffer and the trading price of our common stock could be adversely affected.

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 and meet our debt service obligations.

Our revenues, operating results, available cash, and the carrying value of our natural gas properties, as well as our ability to make capital expenditures (including amounts we expect to invest in connection with our efforts to develop potential CCUS projects) and meet our debt service obligations and other financial commitments, depend significantly upon the prevailing market prices for natural gas and NGLs. According to the U.S. Energy Information Administration (the “EIA”), the historical high and low Henry Hub natural gas spot prices per MMBtu for the following periods were as follows: in 2023, high of $3.78 and low of $1.74; in 2024, high of $13.20 and low of $1.21; and in 2025, high of $9.86 and low of $2.65.

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 and exports of natural gas and NGLs;
- political conditions or conflicts in or affecting other producing regions or countries, including the Middle East, South America, Russia, Ukraine, and China;
- the ongoing military conflicts between Russia and Ukraine and in the Middle East, as well as the related actions of the United States and other governments and governmental organizations relating to oil, natural gas and NGLs, including through sanctions, embargoes, import restrictions and commodity price caps;
- the threat of terrorism and the impact of military action and civil unrest;
- 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;
- 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 natural disasters, including floods, fires, tornadoes, droughts, hurricanes, tropical storms, and severe cold weather;
- domestic and foreign governmental regulations, including environmental initiatives and taxation;

• tariffs, trade restrictions, and other supply chain constraints;

• 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 of, and other financial market conditions affecting 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 period from January 1, 2023 through December 31, 2025, the Henry Hub natural gas spot price reached a high of $13.20 per MMBtu on January 13, 2024 and a low of $1.21 per MMBtu on November 11, 2024. The average Henry Hub natural gas spot prices in 2023, 2024 and 2025 were$2.57 per MMBtu, $2.21 per MMBtu, and $3.52 per MMBtu, respectively, with 2024 being the lowest on record, adjusted for inflation. During the year ended December 31, 2025, there were record high production and less gas consumption, resulting in lower prices, but in the final months of 2025, natural gas prices rose due to weather impacts such as the polar vortex.

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 64%, 62%, and 61%, for the years ended December 31, 2025, 2024, and 2023, respectively, of our total natural gas and NGL production was gathered, processed, and transported by ONEOK (formerly 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 ONEOK on its systems and in its facilities would materially and adversely affect our financial condition and results of operations.

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 creditworthiness 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, and results of operations 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 reserves quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserves 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 timeframe 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 reserves estimates. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas, NGLs, 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.

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.

The present value of future net revenues from our proved reserves will not necessarily be the same as 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, NGLs, 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, 2025, approximately 2,021.8 Bcfe, or 15.2%, of our total estimated proved reserves were undeveloped or behind pipe. The reserves data included in our reserves 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 estimated reserves, which could have a material adverse effect on our financial condition, future cash flows, and results of operations.

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 and results of operations.

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 the pace of drilling and completion of new wells and our ability to secure necessary services and labor. 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, 2025, we carried unproved natural gas, NGL, and oil property costs of $13.2 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 reserves 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 and cash flows.

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, floods, fires, tornadoes, droughts, hurricanes, tropical storms, and severe cold weather.

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 provides us with a network 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 with Atmos and Energy Transfer and firm storage with Energy Transfer. We are obligated under these arrangements to pay a demand charge for firm transportation and storage capacity rights on most of 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.

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 well operations, 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:

- general economic and industry conditions;
- unexpected drilling conditions;
- potential drainage of natural gas from our properties by operations on adjacent properties;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as floods, fires, tornadoes, droughts, hurricanes, tropical storms and severe cold weather, 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, 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.

We may experience certain issues and encounter risks in our drilling operations, including:

- 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;
- 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; and
- other typical shale basin drilling challenges and risks.

We experience certain issues and encounter risks in our hydraulic fracturing, workover, and completions activities, including:

- 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;
- 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; and
- 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, and we could incur material write-downs of unevaluated properties, which may cause the value of our undeveloped acreage to 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 or may in the future experience 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, and cash flows.

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. Further, supply chain disruptions, tariffs and trade restrictions and other inflationary pressures affecting the United States and global economy and the oil and gas industry may limit our ability to procure the necessary products and services for drilling and completing wells in a timely and cost effective manner, which could result in reduced margins and delays in our drilling and completion activities which, in turn, could adversely affect 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, 2025, we operated approximately 97% of our net (81% of our gross) acreage. With respect to our natural gas midstream business, we do not operate the NEPA midstream entities, and in the Barnett, during the year ended December 31, 2025, approximately 80% of our gross operated production volumes were gathered and processed by a third party. 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 third parties, as well as the midstream operations involving our assets depend upon a number of factors outside of our control. These factors include the operator’s schedule and level of capital investment, expertise, financial resources, collaboration with other participants in drilling wells, and the use of technology.

Even though the Bedrock Acquisition is completed, we may be unable to successfully integrate the assets held by BKV Barnett II into our business or achieve the anticipated benefits of the Bedrock Acquisition.

The success of the Bedrock Acquisition will depend, in part, on our ability to realize the anticipated benefits and cost savings from integrating the assets and operations of Bedrock into our business, and there can be no assurance that we will be able to successfully integrate or otherwise realize the anticipated benefits of the Bedrock Acquisition. Difficulties in integrating Bedrock into our company and our ability to manage the combined company may result in us performing differently than expected, in operational challenges or in the delay or failure to realize anticipated expense-related efficiencies and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Potential difficulties that may be encountered in the integration process include, among others:

- the inability to successfully integrate Bedrock operationally, in a manner that permits us to achieve the full revenue, expected cash flows and cost savings anticipated from the Bedrock Acquisition;
- not realizing anticipated operating synergies; and
- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with the Bedrock Acquisition.

Risks Related to Our Power Generation Business

We incurred significant costs in connection with the BKV-BPP Power Joint Venture Transaction.

We incurred significant costs associated with the BKV-BPP Power Joint Venture Transaction. Our fees and expenses related to the BKV-BPP Power Joint Venture Transaction include financial advisor fees, filing fees, taxes and legal and accounting fees. Following the closing, we expect to consolidate our financial statements with those of the BKV-BPP Power Joint Venture. In addition, we expect that with our increased ownership of the BKV-BPP Power Joint Venture, certain expenses related to operating the BKV-BPP Power Joint Venture will increase. It is difficult to predict the total amount of costs related to the BKV-BPP Power Joint Venture Transaction and the increased ownership of the BKV-BPP Power Joint Venture following the closing. Such costs may be significant and could have an adverse effect on our future results of operations, cash flows and financial condition.

We operate our power generation business through a joint venture that requires the consent of BPPUS for certain material actions.

As of December 31, 2025, we and BPPUS each had a 50% interest in the BKV-BPP Power Joint Venture. For the years ended December 31, 2025, 2024, and 2023, the portion of BKV's earnings in the BKV-BPP Power Joint Venture were $14.9 million, $10.4 million, and $16.9 million, respectively, and our interest in the earnings on the BKV-BPP Power Joint Venture represented approximately 1.5%, 1.8%, and 1.7% of our revenues, which includes derivative gains (losses), net, respectively.

Following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, the BKV-BPP Power Joint Venture is owned 75% by BKV and 25% by BPPUS. In accordance with the terms of the Amended and Restated Limited Liability Company Agreement of the BKV-BPP Power Joint Venture (the "BKV-BPP Power LLC Agreement"), which we entered into with BPPUS at the closing of the BKV-BPP Power Joint Venture Transaction, the BKV-BPP Power Joint Venture is managed by a board of managers (the "BKV-BPP Power Board"), which consists of twelve members, nine of whom are appointed by us and three of whom are appointed by BPPUS. Of the nine members who are appointed by us, one or more may be a director of Banpu.

As of January 30, 2026, the BKV-BPP Power LLC Agreement provides that we are delegated the authority and responsibility for the day-to-day operation of the business affairs of BKV-BPP Power. However, for as long as BPPUS maintains an ownership interest in the BKV-BPP Power Joint Venture of at least 10%, consent from at least one member of the BKV-BPP Power Board appointed by BPPUS is required for, and we are not entitled to unilaterally cause the BKV-BPP Power Joint Venture to take, certain specified actions, such as: (i) any sale of the BKV-BPP Power Joint Venture or certain significant subsidiaries, or transfer of substantially all assets, merger, consolidation, amalgamation or similar business combination of the BKV-BPP Power Joint Venture, subject to certain exceptions; (ii) any winding up, dissolution or liquidation or any commencement of or any filing or petition for a voluntary bankruptcy or reorganization; (iii) any amendment, restatement, or revocation of organizational documents, subject to certain exceptions; (iv) any material change in the nature of the business or purpose of the BKV-BPP Power Joint Venture; (v) entry into certain related party transactions; (vi) the issuance, sale, repurchase, or redemption of any of the equity interests of the BKV-BPP Power Joint Venture; (vii) the admission of any new member to the BKV-BPP Power Joint Venture, subject to certain exceptions; (viii) the early termination without the BKV-BPP Power Board approval of, or the execution or material amendment of, any material contract, subject to certain exceptions; (ix) the incurrence of certain indebtedness beyond certain thresholds; and (x) the making of certain capital calls.

We face certain risks associated with shared control of the BKV-BPP Power Joint Venture, and BPPUS may at any time have economic, business, or legal interests or goals that are inconsistent with ours.

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, and cash flows.

The ongoing operation of the Temple Plants 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 the Temple Plants), 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 the Temple Plants could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

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

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

If we make any major modifications to Temple I or Temple II, 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 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 these facilities based on our assessment that such activity will provide adequate financial returns. The modifications to these facilities require 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, and cash flows.

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

The Temple Plants may operate without long-term power sales agreements for some or all of their 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 either facility will be able to operate profitably. This could lead to less predictable revenues, future impairments of either 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 and cash flows.

We do not currently supply our own natural gas directly to the Temple Plants or their firm natural gas storage service at the Bammel storage facility. We cannot ensure that we will be successful in the future in obtaining the commercial contracts necessary to facilitate direct delivery of our natural gas production to the Temple Plants on commercially reasonable terms or at all.

We cannot ensure 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, Temple II, or their firm natural gas storage service at the Bammel storage facility. Although the physical infrastructure exists to supply our own natural gas directly to the Temple Plants 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, and cash flows.

BKV-BPP Power may enter into financially settled 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 may enter 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 may not be 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, and cash flows.

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 power prices, which could have an adverse effect on our financial condition. For example, as of December 31, 2025, BKV-BPP Power had unrealized losses of $19.6 million on its derivative instruments as a result of increased power prices; of the $19.6 million, $13.3 million of these losses pertain to four open HRCOs. In the event BKV-BPP Power enters into an HRCO and is not able to satisfy its obligations, 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 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, and cash flows.

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

Delivery of natural gas to fuel the Temple Plants is dependent upon the infrastructure (including natural gas pipelines) available to serve such generation facilities 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 the Temple Plants 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, and cash flows.

Risks Related to Our Retail Power Business

We operate our retail power business through a joint venture which we share control.

Our retail energy business is operated through BKV-BPP Retail, a wholly-owned subsidiary of the BKV-BPP Power Joint Venture. As of December 31, 2025, we and BPPUS each owned 50% of the BKV-BPP Power Joint Venture. Following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, the BKV-BPP Power Joint Venture is owned 75% by BKV and 25% by BPPUS.

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. For additional information, see "*— Risks Related to Our Power Generation Business — We operate our power generation business through a joint venture that requires the consent of BPPUS for certain material actions*."

Our retail power business operates in a highly competitive environment, which may make it difficult to grow without reducing prices or incurring additional costs.

Our retail business faces substantial competition from other retail electric providers. As a result, we may be forced to reduce prices or incur increased acquisition costs in order to attract and maintain customers. Present and future competitors may have greater name recognition, long-standing customer and broker relationships, greater-financial strength, or other resources that could put us at a disadvantage.

Our retail power business is subject to market price risk.

Our retail business is required to purchase sufficient energy and ancillary services at wholesale to serve its retail customers. Although wholesale prices fluctuate based on market conditions, our retail business has contracted to provide 100% of our customers with fixed power prices. As a result, BKV-BPP Retail is exposed to fluctuations in wholesale energy and ancillary service prices. BKV-BPP Retail seeks to hedge this exposure whenever possible, but hedging instruments may not be economically feasible or available in the required quantities. Additionally, certain components of energy prices cannot be hedged, and there is risk that hedge providers may fail to fulfill their obligations. BKV-BPP Retail's hedging activities do not prevent it from exposure to risk, primarily price fluctuations, including those caused by transmission congestion or extreme weather, which may result in economic losses and liabilities, which could have a material adverse effect on BKV-BPP Retail.

Our retail power business is vulnerable to changes in law, regulation, or market structure resulting in unanticipated costs that cannot be passed through to customers.

Our retail business operates in a highly regulated environment. It is directly regulated by both the PUCT and ERCOT. Changes in regulation could create increased costs that BKV-BPP Retail might be unable to pass through to customers, particularly those on fixed-priced contracts. For example, ERCOT introduced a new ancillary service product — ERCOT Reserve Contingency Service ("ECRS") — in June 2023. Although ERCOT began assessing ECRS charges to BKV-BPP Retail, the PUCT prevented retail suppliers such as BKV-BPP Retail from passing these costs onto existing customers on fixed price contracts. Future changes in law or regulation resulting in increased costs could impact our retail business.

Our retail business, including our relationship with our supplier, is dependent on access to capital and liquidity.

Our business involves entering into contracts to purchase large quantities of electricity. Because of seasonal fluctuations, we often have to purchase electricity and hedges for future periods and finance the purchases upfront until we can recover such amounts from our customers. We also rely on an energy supplier to facilitate our energy and hedge our purchases. If we are unable to renew this agreement or if our energy supplier's credit rating declines, our ability to economically purchase energy and hedges could be impacted. Further, any challenges in securing credit or liquidity on commercially reasonable terms could adversely impact our retail business.

Our retail business depends on our ability to attract and retain personnel with retail market experience.

Our success depends on the expertise of key members of our management team whose loss could disrupt our business operations. Additionally, the PUCT requires us to have one or more officers or managers with at least 15 years of combined experience in the competitive energy industry. Losing certain key personnel could impact our ability to continue operating a retail electric business and jeopardize our retail electric provider ("REP") certificate.

Our retail business depends on maintaining regulated permits and any loss of these permits would adversely affect our business.

Our business requires a REP certificate from the PUCT and a load serving entity ("LSE") registration and qualified scheduling entity ("QSE") registration with ERCOT. Both the PUCT and ERCOT impose various requirements to maintain these permits. Any negative publicity regarding the retail industry in general could result in agencies or the state legislature imposing additional regulations on the retail business and increasing our compliance obligations. Additionally, customer complaints and compliance violations could damage our relationship with the PUCT and potentially jeopardize our REP certificate. Losing our REP certificate, LSE registration, or QSE registration would prevent us from continuing to operate in the retail business.

Risks Related to Our CCUS Business

Our ability to establish and operate 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 limited experience in the development and operation of a CCUS business, which poses different challenges and risks than our existing upstream and natural gas 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 may 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, the Eagle Ford Project, the Cotton Cove Project, and the East Texas Project face, and any of our potential future CCUS projects, including the pipeline of CCUS projects currently under evaluation, will face operational, technological, regulatory, and financial risks. These risks include the possibility that CIP, ONEOK, BPPUS, or any of our other future counterparties to a CCUS project, may not meet their financial or performance obligations related to the CCUS project. Moreover, the economics of our operational and potential CCUS projects depend on financial and tax incentives, including Section 45Q tax credits. If we are unable to obtain the Section 45Q tax credits included in our financial assumptions for any reason, including as a result of any change in policy changes, government spending measures, or U.S. presidential executive actions, any of our proposed CCUS projects may no longer be commercially viable and may not be completed.

Although we have identified potential CCUS projects in addition to the Barnett Zero Project, the Eagle Ford Project, Cotton Cove Project, and the East Texas Project, these additional potential projects are in different stages of the evaluation process. In most cases, emitters have required extended periods of time to evaluate potential projects and participate in negotiations. We have not entered into the definitive agreements necessary to execute any of the other potential projects we have identified and, as such, we cannot guarantee that any of those potential projects will reach FID or be completed. Additionally, we cannot ensure we will be able to source and identify additional emitters willing to enter into CCUS project agreements with us. We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives (and retains) or purchases. 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 our existing pipeline of CCUS projects.

Further, our ability to successfully operate the Barnett Zero Project with ONEOK, or successfully develop the Eagle Ford Project and the Cotton Cove Project with BPPUS, and the East Texas Project, or any future potential CCUS projects, 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 no 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 needed for the entire geologic formation. 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 any greenhouse gas reporting requirements.

• 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/or state governments may cease supporting carbon capture and sequestration.

• In addition to the BKV-CIP Joint Venture and the BKV-BPP Cotton Cove Joint Venture, 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.

Our CCUS projects are expected to have material capital requirements, and we expect to fund up to 50% of these CCUS projects from a variety of external sources, which may include joint ventures, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. 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 our positive net income 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.

Additionally, the development of CCUS projects through our current or potential future joint ventures involves risks not present in investments in which a third party is not involved, including the possibility that:

• we and a co-venturer or partner may reach an impasse on a major decision that requires the approval of both parties;

• we may not have exclusive control over the development, financing, management, and other aspects of the joint venture, which may prevent us from taking actions that are in our best interest but opposed by a co-venturer or partner;

• a co-venturer or partner may encounter liquidity or insolvency issues or may become bankrupt, which may mean that we and any other remaining co-venturers or partners generally would remain liable for the joint venture's liabilities;

• a co-venturer or partner may at any time have economic or business interests or goals that are or may become inconsistent with ours;

• a co-venturer or partner may be in a position to take action contrary to our instructions, requests, policies, or investment objectives, including our current policy with respect to maintaining our qualification for enhanced Section 45Q tax credits under the Code;

• a co-venturer or partner may take actions that subject us to liabilities in excess of, or other than, those contemplated;

• in certain circumstances, we may be liable for actions of our co-venturer or partner;

• our joint venture agreements may restrict the transfer of a co-venturer's or partner's interest or otherwise restrict our ability to sell the interest when we desire or on advantageous terms;

• our joint venture agreements may contain buy-sell provisions pursuant to which one co-venturer or partner may initiate procedures requiring the other co-venturer or partner to choose between buying the other co-venturer's or partner's interest or selling its interest to that co-venturer or partner;

• if a joint venture agreement is terminated or dissolved, we may not continue to own or operate the interests or investments underlying the joint venture relationship or may need to purchase such interests or investments at a premium to the market price to continue ownership; or

• disputes between us and a co-venturer or partner may result in litigation or arbitration that could increase our expenses and prevent our management from focusing their time and attention on our business.

Any of the above could materially and adversely affect our ability to execute on our CCUS strategy, the value of any CCUS project we develop through a current or potential future joint venture, and 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, and results of operations.

We operate the Barnett Zero Project through a joint venture that requires the consent of CIP for certain material actions.

The BKV-CIP Joint Venture is owned 51% by BKV dCarbon Ventures and 49% by CIP and was formed on May 8, 2025 for the purpose of developing CCUS projects. In accordance with the terms of the Limited Liability Company Agreement of BKV dCarbon Project (the "BKV-CIP LLC Agreement"), the BKV-CIP Joint Venture is governed by a board of managers (the "BKV-CIP Board") consisting of five members, three of whom are designated by dCarbon Ventures and two of whom are designated by CIP. Most operational decisions and activities of the BKV-CIP Joint Venture are reserved for approval by a majority of the members of the BKV-CIP Board, but CIP has customary minority investor rights, including veto rights with respect to, among other things, (i) the amount and timing of distributions to the members of BKV dCarbon Project, (ii) BKV dCarbon Project's annual budget, (iii) any sale or initial public offering of BKV dCarbon Project, (iv) any change in senior management of the BKV dCarbon Project, and (v) other significant and related party transactions entered into by the joint venture. Other than quarterly tax distributions and distributions in respect of a deemed liquidation event (as defined in the BKV-CIP LLC Agreement), distributions will be made in accordance with a waterfall until specified minimum return targets are achieved by CIP.

We have agreed that BKV and its affiliates will develop CCUS projects exclusively through the BKV-CIP Joint Venture except that any CCUS projects that are rejected by CIP for development by the BKV-CIP Joint Venture may be developed solely through dCarbon Ventures outside of the BKV-CIP Joint Venture. In addition, the BKV-CIP Joint Venture will retain and monetize all environmental attributes associated with CCUS projects contributed to the BKV-CIP Joint Venture, including pursuant to a first right of BKV or its affiliates to purchase such environmental attributes at fair market value. Ultimately, with respect to CCUS projects contributed to the BKV-CIP Joint Venture, we will be able to apply to offset our own GHG emissions only the portion of sequestered emissions attributable to the percentage of environmental attributes that BKV purchases from the BKV-CIP Joint Venture, which may negatively impact our net-zero strategy, including by delaying or preventing our achievement of net zero. As of December 31, 2025, dCarbon Ventures has contributed the BKV dCarbon Barnett Zero, LLC and BKV dCarbon Las Tiendas, LLC and related assets (including the Barnett Zero and Eagle Ford CCUS projects) and $4.1 million of Section 45Q accrued receivables at carrying value, and committed to future contributions of certain CCUS projects, related assets, and/or cash to the BKV-CIP Joint Venture.

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 operate the Cotton Cove Project through a joint venture that requires the consent of BPPUS for certain material actions.

The BKV-BPP Cotton Cove Joint Venture is owned 51% by BKV dCarbon Ventures and 49% by BPPUS and was formed on August 25, 2023 to own the Cotton Cove Project. In accordance with the terms of the Limited Liability Company Agreement of BKV-BPP Cotton Cove (the "BKV-BPP Cotton Cove LLC Agreement"), the BKV-BPP Cotton Cove Joint Venture is managed by a board of managers (the "Cotton Cove JV Board") consisting of six members, four of whom are appointed by BKV dCarbon Ventures and two of whom are appointed by BPPUS. Of the four members appointed by BKV dCarbon Ventures, none are employees of Banpu who also serve on our board of directors. Additionally, certain material actions require the unanimous consent of the Cotton Cove JV Board and consequently, BKV-BPP Cotton Cove may not take certain material actions without the consent of BPPUS, such as (i) making certain elections available to BKV-BPP Cotton Cove with respect to the monetization of Section 45Q credits; (ii) approving certain final investment decisions related to the Cotton Cove Project; (iii) directing transfers of BKV-BPP Cotton Cove membership interests to unaffiliated third parties; (iv) entering into any merger, consolidation, amalgamation, conversion of BKV-BPP Cotton Cove or any of its subsidiaries, into another form or entity, or any other business combination of any nature; (v) causing the wind up, dissolution, liquidation, commencement, or any filing or petition for a voluntary bankruptcy, reorganization, debt arrangement involving BKV-BPP Cotton Cove; (vi) authorizing any amendment, restatement or revocation of the organizational documents of BKV-BPP Cotton Cove or its subsidiaries; (vii) authorizing increases or decrease of the required capital contributions; (viii) determining the location of the wells associated with the Cotton Cove Project; (ix) making decisions related to a possible initial public offering of BKV-BPP Cotton Cove; or (x) causing BKV-BPP Cotton Cove to make distributions.

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.

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. In addition, 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 for any reason, including as a result of policy changes, government spending adjustments, or U.S. presidential executive actions, many of our proposed CCUS projects may no longer be commercially viable and may not be completed. As an example, the EPA has proposed to rescind the greenhouse gas reporting program, compliance with which is necessary to qualify for the Section 45Q tax credits; if the EPA proceeds with this proposal, we may not be able to comply with the Section 45Q tax credit requirements that are proposed by the Treasury Department as a replacement. We cannot ensure that we will be successful in obtaining any or all of the Section 45Q tax credits currently available. Additionally, we may not receive 100% of the Section 45Q tax credits associated with CCUS projects funded in whole or in part by third parties and, in such cases, will receive only a corresponding percentage of the anticipated Section 45Q tax credits associated with such projects. Moreover, for CCUS facilities that begin construction after 2025, federal tax legislation enacted on July 4, 2025 provides new foreign entity of concern requirements that restrict availability of Section 45Q credits if the entity that owns the facility has certain relationships with or makes certain payments to foreign entities of concern.

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 in a timely manner, 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 continue to successfully operate the Barnett Zero Project with ONEOK in the Barnett, or successfully develop the Eagle Ford Project and the Cotton Cove Project with BPPUS, or any future CCUS projects and any failure to do so in whole or in any significant part 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, and results of operations.

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, which include the following:

- 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;
- 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; and
- 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.

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 and cash flows.

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 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, and cash flows. 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, and financing for these development projects may not be available on economically acceptable terms or at all. Moreover, our revenues may not increase immediately, or at all, upon the expenditure of funds on a particular project. 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 construct and operate our assets on 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, 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, 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, NGLs, 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 flows 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.

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, and cash flows.

A financial crisis, armed conflict, or deterioration in general economic, business, or industry conditions could materially adversely affect our results of operations and financial condition.

Concerns over global economic conditions, stock market volatility, energy costs, geopolitical issues, inflation and the U.S. Federal Reserve interest rate adjustments in response, the availability and cost of credit, and the 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.

Our business has also been impacted by economic conditions and disruptions in global financial markets such as reduced energy demand, inflation, and labor shortages. There was uncertainty during 2024 and 2025 with potential economic downturns or recessions in parts of the United States and globally, which continues into 2026 with global conflicts involving Russia, Ukraine, the Middle East, among others. Due to uncertainty in inflation, we may continue to see global, industry-wide supply chain disruptions and widespread shortages of labor, materials, and services. Such shortages have resulted in our facing significant cost increases for labor, materials, and services, and we expect these shortages and cost increases to continue. We are currently in a period of marginally increasing natural gas prices; however, the cost of labor, materials, and services remains high and may not adjust in proportion to increases in natural gas prices. We cannot predict the future inflation rate but if inflation elevates, 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 from higher costs through increases in commodity prices or from our current revenue stream, then our estimates of future reserves, impairment assessments of natural gas and oil properties, and values of properties in purchase and sale transactions may all be significantly impacted. Although macroeconomic inflation is easing, these inflationary pressures may have an impact on our liquidity position 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. We will also continue to monitor the impacts of inflation and commodity price volatility and the effects on our business, including to our customers and our partners.

The occurrence or threat of terrorist attacks in the U.S. or any of the major energy producing regions of the world or elsewhere, anti-terrorist efforts and other armed conflicts involving the U.S. or other countries, including the conflicts between Russia and Ukraine and in the Middle East, which may include further sanctions, embargoes, export controls, supply chain disruptions, regional instability and geopolitical shifts, may have adverse effects on global macroeconomic conditions, increase volatility in the price and demand for oil and natural gas, increase exposure to cyberattacks (including cyberattacks targeting energy and pipeline infrastructure), cause disruptions in global supply chains, increase transportation and insurance costs, increase foreign currency fluctuations, cause constraints or disruption in the capital markets and limit sources of liquidity. Additionally, destructive forms of protest and opposition by extremists and other disruptions, including acts of sabotage or eco-terrorism, against oil and natural gas activities could potentially result in personal injury to persons, damages to property, natural resources or the environment, or lead to extended interruptions of our or our customers' operations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and gas. Oil and gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our or our customers' operations is destroyed or damaged. Expenses related to security and costs for insurance may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all. We cannot predict the extent of these events' effects on our business and results of operations as well as on the global economy and energy markets.

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 and financial condition. 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, could have a material adverse effect on our business, liquidity, financial condition, results of operations and cash flows.

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, and cash flows. The extent to which any future pandemic, epidemic, outbreak, or other public health event could impact our business will depend on numerous evolving factors that we may not be able to accurately predict.

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 the BKV-BPP Power Joint Venture's solar facility, are each important factors to our potential ability to achieve our emissions goal of net zero Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses during the early 2030s and aspirations to offset Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. We may not meet our near-term or long-term goals by our target date or at all.

Our estimated sequestration rates from our CCUS business and our emissions reduction expected from our initiatives and our associated expected emission offsets and/or other environmental attributes 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, regulatory changes addressing the use of "net zero" in environmental marketing claims, or new developments related to climate science could impact our ability to claim emissions reductions related to our CCUS business or otherwise. For more information, see "— *Risks Related to Environmental, Legal Compliance, and Regulatory Matters*." 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.

Our ability to develop and operate large-scale CCUS projects involves significant risks and uncertainties, and we may be unable to execute some or all of these projects, including those for which we have reached FID, within the expected timeline, on terms acceptable to us, or at all. Our CCUS business and nearly all of our CCUS projects are in the early stages of development. Although we commenced commercial operations with the initial injection of CO_2 waste at the Barnett Zero Project in November 2023, and have reached FID and entered into definitive agreements with respect to the Eagle Ford Project, the Cotton Cove Project, and the East Texas Project, we have not reached FID with respect to or entered into the definitive agreements necessary to execute any of the other potential projects described 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 fund the anticipated capital requirements for the potential projects that we have identified through external funding and revenues from our upstream business. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. 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.

Even if we are able to successfully develop and operate such projects, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties. In addition, in the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside of our value chain. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives (and retains) or purchases, which may negatively impact our net zero strategy, including by delaying or preventing our achievement of net zero.

We have already had to extend out the timing for our achievement of our net zero goals and we may have to do so again in the future. Any disputes or ambiguities regarding the right to claim environmental attributes, may also increase the risk of double-counting of such attributes, which may negatively affect our ability to reach our net zero goals and negatively affect perceptions of our operations and products. Additionally, we may purchase various credits or offsets that may be deemed to mitigate our emissions impact instead of actual changes in our emissions reduction performance in order to meet our emissions reduction goals. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, that the offsets we do purchase will successfully achieve the emissions reductions they represent or that such offsets will be deemed sufficient by third parties to whom we may seek to market our products with certain environmental attributes or product claims. There can be no assurances that we will be able to execute on our strategy to meet our Scope 1, 2, and 3 owned and operated upstream and natural gas midstream emissions goals.

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

As of March 6, 2026, we had outstanding long-term debt of $610.0 million, which consisted of $110.0 million of borrowings under the RBL Credit Agreement and $500.0 million of borrowings under the 2030 Senior Notes. We intend, from time to time, to use borrowings available under the RBL Credit Agreement for working capital purposes, to fund capital expenditures for the acquisition, development, and exploration of oil and gas properties, and for general company purposes.

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.

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, the syndicated bank market, 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 RBL 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; and/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.

We may be unable to achieve or maintain a low target level of indebtedness, which may limit our liquidity, financial flexibility, and future operations.

Subject to the terms of the agreements governing our existing debt, 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, and increase our interest rates;

• 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 amount available for borrowing under the RBL Credit Agreement is subject to a borrowing base, which is determined by the lenders under the RBL Credit Agreement, taking into account our estimated proved reserves and related properties and is subject to periodic re-determinations based on pricing models determined by the lenders at such time. Declines in natural gas and oil prices adversely impact the value of our oil and gas properties and, in turn, the market values used by our lenders to determine our borrowing base and could result in a determination to lower our borrowing base, reducing our financial flexibility and liquidity.

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 and certain other 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 agreements governing our existing indebtedness 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 agreements governing our existing indebtedness on BKV Upstream Midstream's and its restricted subsidiaries' ability to pay dividends to their stockholders (including to BKV Corporation), see "— *Risks Related to Our Common Stock — The agreements governing our indebtedness impose restrictions on dividend payments*."

In addition, the agreements governing our existing indebtedness require BKV Upstream Midstream and its restricted subsidiaries to maintain, and future debt agreements may require us to maintain, compliance with covenants and, in certain instances, including the RBL Credit Agreement financial ratios.

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 and the foreclosure of liens on our assets.

If we are unable to comply with the restrictions and covenants in any of our existing debt agreements or any future debt agreement, or if we default under the terms of any of our existing debt agreements, or any future debt agreement, there could be an event of default under our debt agreements. Our ability to comply with these restrictions and covenants, including meeting any financial ratios and covenants, may be affected by events beyond our control. Further, if, any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of BKV's equity interests, or if any person or group acquires a greater percentage of BKV's equity interests than are then held by Banpu and its controlled affiliates (excluding portfolio companies and operating companies of Banpu), such event will be an event of default under the RBL Credit Agreement, which may result in amounts owed by us thereunder to become immediately due and payable. In addition, if any person or group (other than Banpu and its controlled affiliates) acquires more than 50% of BKV's equity interests, unless Banpu and its controlled affiliates retain the right to appoint a majority of the directors of BKV Upstream Midstream, and Moody's or S&P decreases their rating of the 2030 Senior Notes as a result thereof within 60 days, holders of the 2030 Senior Notes will be entitled to require BKV Upstream Midstream to repurchase all or any part of that holder's 2030 Senior Notes pursuant to an offer on the terms set forth in the indenture governing the 2030 Senior Notes. Banpu has no obligation to maintain any particular percentage of equity ownership in the Company and 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 our existing debt agreements or any future debt agreement, the debt holders could terminate their commitments to lend or accelerate the debt and declare all amounts borrowed due and payable, as applicable. Our obligations under the RBL Credit Agreement are secured by liens on substantially all of BKV's and BKV Upstream Midstream's assets and those of BKV Upstream Midstream's restricted subsidiaries that guarantee our obligations under the RBL Credit Agreement, and an event of default under the RBL Credit Agreement could result in the foreclosure of such liens. 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 our existing debt agreements or any future debt agreement or obtain needed waivers on satisfactory terms.

Sustained, decreased natural gas prices could cause non-compliance with the Company's financial covenants. Non-compliance with financial debt covenants would limit the Company's ability to draw on its existing credit facility under the RBL Credit Agreement and could also result in our debt agreements being called early, which would move certain noncurrent 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 noncurrent financial obligations based on our current forecasts.

As a result of cross-default provisions in our debt agreements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.

The terms of our existing debt agreements, including the RBL Credit Agreement and the indenture governing the 2030 Senior Notes, contain cross-default provisions which provide that we could be in default under such agreements in the event of certain defaults under our other debt agreements. Accordingly, should an event of default above certain thresholds occur under any of those agreements, we face the prospect of being in default under all of our debt agreements, obligated in such instance to satisfy all of our outstanding indebtedness but in all probability unable to satisfy all of our outstanding obligations simultaneously. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us, which would negatively affect our ability to continue our business plan, make capital expenditures and finance our operations.

Our borrowings under the RBL Credit Agreement expose us to interest rate risk.

Our results of operations are exposed to interest rate risk associated with borrowings under the RBL Credit Agreement, which bear interest at rates based on SOFR or an alternative floating interest rate benchmark. In 2025, the U.S. Federal Reserve lowered interest rates three times. Interest rates are currently expected to continue to decrease in 2026 and possibly into 2027. 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 increase in the future, or such interest rates do not decrease over the next few years, it may have a material adverse effect on our results of operations and financial condition.

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.

We enter into derivatives contracts in connection with our natural gas and NGLs, including, for instance, commodity price swaps, basis swaps, put and call options, and producer 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 consolidated statements of operations 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, 2025, 2024, and 2023, we had realized losses of $8.1 million, and realized gains of $112.5 million, and $90.2 million, respectively, of which $13.3 million of the $112.5 million and $46.7 million of the $90.2 million of gains related to early termination of hedges. For the years ended December 31, 2025, 2024, and 2023, we incurred unrealized gains on derivatives of $113.2 million, unrealized losses on derivatives of $146.7 million, and unrealized gains on derivatives of $148.6 million, respectively. 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, 2025, we have hedged 965,286 MMBtu/d, 305,180 MMBtu/d, and 172,535 MMBtu/d for 2026, 2027, and 2028, respectively, of which 471,105 MMBtu/d, 112,174 MMBtu/d, and 2,541 MMBtu/d, respectively, represented basis swaps. In addition, as of December 31, 2025, we have hedged 16,614 Bbl/d and 7,164 Bbl/d of NGLs for 2026 and 2027, respectively. 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.

Subject to restrictions in the RBL 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, and cash flows. 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 wholly-owned subsidiaries and joint ventures, including the BKV-BPP Power Joint Venture and the BKV-BPP Cotton Cove 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 joint ventures. Our subsidiaries' and joint ventures' respective abilities 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 NGL 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, and the proceeds of any insurance may not be received in a timely manner. 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 natural gas midstream properties, operational control of wells, redrilling expenses, pollution and cleanup, site pollution incidents, damage to lease property, business and contingent business interruption, including cybersecurity, management liability, automobile liability, third-party liability, workers' compensation, employer's liability, 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, and results of operations.

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 have and may continue to 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.

These assessments are 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 liabilities, environmental issues, or other 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, and cash flows.

In addition, the RBL Credit Agreement (solely with respect to BKV Upstream Midstream and its restricted subsidiaries) and the indenture governing the 2030 Senior Notes prohibits us from entering into certain 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.

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. 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 RBL 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 and prevailing basis differentials;
- 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 RBL 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, a 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 RBL Credit Agreement is 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, and results of operations.

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. They may also be better positioned to contract for drilling, production and workover equipment, pay higher wages to secure trained personnel, and absorb the burden of current 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. Additionally, there is strong competition for desirable natural gas, NGL, and oil-producing properties, energy companies, undeveloped leases, drilling rights, and CCUS projects. Further, inflation may affect us more severely 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 and results of operations.

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

Our business faces 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, including but not limited to human error, power outages, computer and telecommunication failures, natural disasters, fraud or malice, social engineering or phishing attacks, viruses or malware, and other cyberattacks, such as denial-of-service or ransomware attacks. Reports indicate that certain entities or groups, including cybercriminals, competitors, and nation state actors, have mounted cyber-attacks on businesses and other organizations solely to disable or disrupt computer systems, disrupt operations, and, in some cases, steal data. While we maintain a robust cybersecurity program, which includes administrative, technical, and organizational safeguards, a significant cyberattack or other cyber incident (whether involving our systems, those of a critical third-party, or both) could disrupt our operations and result in downtime, loss of revenue, harm to the Company's reputation, or the loss, theft, corruption, or unauthorized release of critical data of us or those with whom we do business, as well as result in higher costs to correct and remedy the effects of such incidents, including potential extortion payments associated with ransomware or ransom demands. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may also result in increased capital and operating costs. As of March 6, 2026, we were not aware of any cybersecurity threats or incidents that have materially affected or are reasonably likely to materially affect the Company, including our business strategy, results of operations or financial standing. However, there can be no assurance that our procedures and controls will be sufficient to prevent or mitigate security breaches, which could lead to losses of sensitive information, critical infrastructure, or capabilities essential to our operations, all of which could have a material adverse effect on our business, financial position, results of operations, and cash flows. In addition, to assist in conducting our business, we rely on information technology systems and data hosting facilities, including systems and facilities that are hosted by third parties to which we have limited visibility and control. Even though we carry cyber insurance that may provide insurance coverage under certain circumstances, we might suffer losses as a result of a security breach or cyber incident that exceeds the coverage available under our policy or for which we do not have coverage, and we cannot be certain that cyber insurance will continue to be available to us on commercially reasonable terms, or at all. The use by BKV and its third-party service providers to a hybrid systems model, including on-premises and cloud environments, has transformed how systems interconnect, how data is stored, how users interact with applications, and what end user devices are utilized. This hybrid systems model has resulted in additional cybersecurity risk, and cybersecurity attacks, particularly amidst the increased adoption of artificial intelligence technologies, are becoming more sophisticated. These events could damage our reputation and lead to financial losses from remedial actions, loss of business, or potential liability.

Moreover, the rapid advancement and increased adoption of artificial intelligence and machine learning technologies have given rise to additional vulnerabilities and potential entry points for cyberattacks, including a risk of exposure of confidential, proprietary or other sensitive information through the inadvertent use of open artificial intelligence tools. These technologies can be exploited by malicious actors to enhance the sophistication, scale or intensity of cyberattacks, making it more challenging to detect and mitigate such threats.

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.

Similarly, some activists view CCUS as a means to either promote the fossil fuel industry or avoid transition to other sources of energy, and thus, are often opposed to such projects regardless of any potential environmental benefits. We may need to incur significant costs associated with responding to these or other 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, and results of operations.

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, and cash flows.

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, and cash flows. 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, future business prospects, financial condition, results of operations, and cash flows.

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.

In addition, Christopher Kalnin serves as a member of Banpu's Executive Committee with responsibilities to Banpu to, among other things, manage all aspects of Banpu's business in North America. Although our corporate opportunity policy requires Mr. Kalnin to present applicable business opportunities sourced by him to BKV before such opportunities may be presented to Banpu, Banpu or its affiliates may compete with us for acquisition or other business opportunities. Our independent directors also serve, or may in the future serve, as officers and board members for other entities. If our officers' and directors' other business affairs require them to devote substantial amounts of time to such affairs, it could limit their ability to devote time to our affairs which may have a negative impact on our ability to compete or follow the elements of our business strategy.

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

We are classified as an "emerging growth company" as defined in Section 2(a)(19) of the Securities Act, including as modified by the JOBS Act. In addition, we have reduced Sarbanes-Oxley Act compliance requirements, as discussed elsewhere, for as long as we are an emerging growth company, which may be up to five full fiscal years. Unlike other public companies, we will not be required to, among other things, (i) comply with any new requirements adopted by the Public Company Accounting Oversight Board ("PCAOB") requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (ii) provide certain disclosure regarding executive compensation required of larger public companies, or (iii) hold nonbinding advisory votes on executive compensation.

To the extent that we rely on any of the exemptions available to emerging growth companies, less information will be provided about our executive compensation and internal control over financial reporting compared to non-emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

We expect to lose emerging growth company status as of December 31, 2026.

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 could be adversely affected.

Changing sentiments towards ESG matters and environmental conservation measures may adversely impact our business.

Changing sentiments towards 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. Changing sentiments towards 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 occasionally create and publish voluntary disclosures regarding ESG matters, many of the statements in these disclosures are based on hypothetical expectations and assumptions, which may not be representative of current or actual risks or events, or forecasts of expected risks or events, including the associated costs. 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. ESG programs and disclosures are currently in disfavor at the federal level as well as in some states, which may cause other states to increase levels of ESG-related regulation, along with increased stakeholder and non-governmental organizational engagement in ESG matters. 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 recognize that standards and expectations for carbon accounting as well as the methods for measuring GHG emissions and environmental attributes, such as offsets and renewable energy credits, are evolving. Our current and future approaches to measuring and implementing reductions and achieving goals like "net zero" or a "closed-loop" system may be viewed by some stakeholders as inconsistent with emerging or common best practices depending on individual interpretations or expectations. If our approaches to such matters are inconsistent with particular stakeholder expectations, we may face increased scrutiny, criticism, regulatory actions, and investor concerns, or litigation, any of which may adversely impact our business, financial condition or results of operations. For example, there has been increasing scrutiny on and criticism of the certification or labeling of certain fossil fuel products as “responsible” or similar labels, as well as on various marketing or other claims related to the use of offsets or the emission profile of products, given alleged deficiencies in the monitoring processes used to support such certifications or claims, which may adversely impact demand for, and any premium associated with, such certifications and claims. Our plans and claims regarding our Pad of the Future and RSG programs, and our intent to produce Carbon Sequestered Gas, may come under criticism, expose us to potential litigation, or otherwise impact our reputation and financial performance. For example, our plan to retire carbon credits against our Scope 1 and Scope 3 emissions instead of transferring such credits with our produced natural gas may impact certain customers’ willingness or ability to use Carbon Sequestered Gas to meet their own emissions goals, and thus adversely impact demand for such product. Additionally, disputes or ambiguities regarding the methodologies used to certify and register carbon credits associated with CCUS projects could delay or prevent our efforts to certify and register the environmental attributes associated with our CCUS projects as tradeable carbon credits, including the development of a blockchain ledger and tokens to facilitate the transfer of environmental attributes, which may negatively impact our net zero strategy, including by delaying or preventing our achievement of net zero. Such failure may also otherwise impact our operations to the extent such certification or similar condition is required, such as with our contract with a subsidiary of Kiewit. In certain cases, our emissions reduction and other ESG efforts rely on third parties, whose actions or timelines may not align with our expectations. Additionally, even if we achieve our net zero goals as described herein, we may not fully realize the intended benefits if other stakeholders disagree with our goals, structure, methodology, accounting practices, or data sources in achieving them.

Additionally, various regulators have adopted, or are considering adopting, regulations on environmental marketing claims, including, but not limited to, the use of climate-related language such as “net zero” in product marketing. These requirements may use different criteria or methodologies than we currently use in assessing our net zero strategy or products, such as our intentions to develop Carbon Sequestered Gas. Any new regulations adopted, or reinterpretations of new ones, may require us to change our internal assessment criteria, limit the use of certain marketing claims, reduce the benefit of initiatives we implemented, or adversely affect our operations.

Changing sentiments towards global climate change has resulted in increased investor attention and 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, 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 these allegations cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future.

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 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. 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 and institutional investors who provide financing to fossil-fuel energy companies also have become more attentive to sustainable financing practices and some of them may elect not to provide funding for fossil fuel energy companies, which could result in the restriction, delay, or cancellation of drilling or development programs or production activities and affect our access to capital for potential growth projects. For example, the international community gathered in Glasgow, Scotland, U.K. at the 26th Conference to the Parties ("COP26") on the UN Framework Convention on Climate Change ("UNFCCC"), and 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. On January 7, 2026, President Trump issued a Presidential Memorandum entitled "Withdrawing the United States from International Organizations, Conventions, and Treaties that Are Contrary to the Interests of the United States," which directs executive agencies to take immediate steps to remove the United States from 66 listed treaties or organizations, including the UNFCCC and the Intergovernmental Panel on Climate Change. Although the Trump Administration has shifted policies at the federal level, risks identified in this section resulting from other drivers are expected to persist in any event, and there could be another shift at the federal level in the future.

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, NGLs, and oil.

Energy conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to natural gas, NGLs, 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, and cash flows.

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, floods, and freezes), 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 may include damages to our facilities from powerful winds or rising waters in low lying areas, disruption to production due to climate-related damages or increased operational costs, the need for less efficient or non-routine operating practices caused by climate effects, or increased insurance costs resulting from 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 are continuously implementing plans that address the potential impacts of climate change on our operations, but we cannot guarantee 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. Congress, from time to time, has considered legislation to amend the 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. Such 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 may consider 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, and cash flow.

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 was contemplated, but ultimately rejected in Texas. If Texas were to decide to limit the production of crude oil 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 that apply to our operations 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 reserves 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, 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, political, 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, in August 2022, Congress passed, and former President Biden signed into law, the Inflation Reduction Act of 2022, which, for the first time ever, imposes a fee on GHG emissions from certain facilities. However, the OBBBA delayed implementation of these emissions fees for the oil and gas industry until 2034. The emissions fee requirements, if they ultimately take effect, 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 and the EPA's subsequent Endangerment Finding, 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, former President Biden signed a resolution passed by Congress under the Congressional Review Act nullifying the September 2020 rule, effectively reinstating the prior standards. On March 8, 2024, the EPA published its Methane Rule, which took effect on May 7, 2024 and established requirements for methane emissions from existing and modified oil and gas sources and imposed additional requirements for new sources with respect to methane emissions, including sources not previously regulated under the oil and gas source category. However, on December 3, 2025, the EPA issued a final rule delaying by 18 months key compliance deadlines in the March 8, 2024 Methane Rule. Further, the Methane Rule and the December 2025 rule delaying its implementation are currently being challenged in the federal courts. In addition, on May 6, 2024, the EPA released its revised regulations for GHG emissions reporting ("Subpart W Regulations") that will have an impact on the quantity of GHG emissions reported and the associated payment of fees under the Waste Emissions Charge imposed by the IRA that may be applicable to our operations. However, on September 16, 2025, the EPA proposed a rollback of the GHG reporting regulations that would end reporting under the GHG emissions reporting program for the natural gas distribution industry and for all sectors other than those subject to the Subpart W Regulations and would pause reporting under the Subpart W Regulations until 2034. Separately, on February 18, 2026, the EPA published a final rule rescinding the Endangerment Finding, which underpins the EPA's regulation of GHGs. The rescission has been challenged in court, which could result in the rescission being stayed, overturned, or limited in scope or effect. For more information, see "*Business - Government Regulation and Environmental Matters*." We continue to review additional changes to rules, such as the revised regulations issued by the Bureau of Land Management to reduce flaring and natural gas waste on federal leases or updates to its onshore oil and gas leasing rules that may impact our current or future operations.

While the Trump administration has rolled back or is proposing to roll back many regulations and findings related to GHG emissions and their effects on public health and welfare, a future administration may seek to impose new legislation or rules related to GHG emissions that could impact our operations. Further, 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, the United States was an original party to the Paris Agreement, but withdrew in 2020, rejoined in 2021, and withdrew again, effective January 27, 2026, pursuant a January 2025 order issued by President Trump. It is possible that the United States will rejoin the Paris Agreement in the future and make commitments to reduce GHG emissions and move toward a global net zero economy as it has done in the past. To the extent developments result in new restrictions on natural gas and NGL operations, increase operational costs, or otherwise reduce the demand for natural gas and NGLs, our business could be materially adversely effected. For more information, see "*Business - Government Regulation and Environmental Matters*."

Additionally, in March 2024, the SEC finalized a new rule that would require the reporting of climate-related risks and financial impacts, as well as GHG emissions for larger companies. On April 4, 2024, the SEC issued an order staying implementation of the SEC climate disclosure rule pending judicial review of various legal challenges to the rule, which were consolidated into the Eighth Circuit Court of Appeals. On March 27, 2025, the SEC voted to end the defense of the rules in the litigation and, on July 23, 2025, it filed a status report requesting that the Eighth Circuit proceed with the case and issue an opinion on the challenges to the climate disclosure rule. On September 12, 2025, the Eighth Circuit denied the SEC's request to proceed with the case and indicated that the case would be held in abeyance until the SEC either renews its defense of the rules or revises the rules via notice-and-comment rulemaking. We continue to monitor the status of this rule, but we cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. In addition, other policymakers, including the State of California, have adopted (or are considering adopting) similar or more stringent regulations. 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 CWA, which regulates the discharge 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 RCRA, which imposes requirements for the generation, treatment, storage, transport, disposal, and cleanup of nonhazardous and hazardous wastes;

• the 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 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 depend on these contractors to provide trained labor as well as equipment that is properly designed, maintained, and tailored to their specific 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 delivery requirements and complaint-based state regulation regarding our rates, terms, and conditions of service. Our NGL gathering pipelines and operations may also fall under 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.

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

The Temple Plants are 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, operational, 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. We may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment if any of the following occur: (i) water produced from our projects fails to meet the quality requirements set by relevant regulatory agencies, (ii) our wells produce water in excess of the allowed volumetric permit limits, (iii) the disposal wells fail to comply with applicable regulatory requirements, or (iv) we are unable to secure access to disposal wells with sufficient capacity to handle all of the produced water. 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 U.S., 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. Additionally, regulators in some states have modified their regulations or guidance to mitigate potential causes of induced seismicity. 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 issued a notice of 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. To implement these changes outlined in the 2016 notice of proposed rulemaking, PHMSA promulgated three separate major rules (collectively referred to as the "Gas Mega Rule"), which include rules focused on: the safety of gas transmission pipelines, the safety of hazardous liquid pipelines, and enhanced emergency order procedures.

The first component of the Gas Mega Rule, the gas transmission rule, was finalized in October 2019 and 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. PHMSA promulgated the second component of the Gas Mega Rule in November 2021, extending federal safety requirements to onshore gas gathering pipelines with large diameters and high operating pressures.

The final of the three components of the Gas Mega Rule was published on August 24, 2022 and took effect on May 24, 2023 and 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 2025, the maximum civil penalties PHMSA can impose are $272,926 per pipeline safety violation per day, with a maximum of $2,729,245 for a related series of violations. However, the proposed Pipeline Safety Act of 2025, S. 2975, would increase these maximum civil penalty amounts to $400,000 and $4,000,000, respectively.

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 migratory birds or various threatened or endangered species, 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 as threatened or endangered in areas where we operate 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 are always 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 either determine that we are required to make a mandatory filing, submit to CFIUS review on a voluntary basis, or 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, and cash flows.

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, and cash flows.

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 or implemented, and it is not possible at this time to predict when, or if, this will be accomplished.

Effective March 15, 2021, the CFTC implemented its final rule concerning speculative position limits, adopting new and amended federal spot-month limits for 25 physical commodity derivatives. Under this rule, 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.

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. With the implementation of the final aggregation rules and adoption of the final CFTC position limits rules, our ability to execute our hedging strategies described above could be limited.

The CFTC issued a final rule on margin requirements for uncleared swap transactions on January 6, 2016. This final rule was amended on February 24, 2021 to permit the application of a minimum transfer amount of up to $50,000 for each separately managed account of a legal entity that is a counterparty to a swap dealer or a major swap participant in an uncleared swap transaction and to permit the application of separate minimum transfer amounts for initial margin and variation margin.

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 or amend 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 financial counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which 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, who 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 our cash flows may be 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, and cash flows.

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. 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, 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 cash flows.

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

The regulatory environment surrounding cybersecurity, data privacy and protection, and the unauthorized disclosure of personal or confidential information is constantly evolving and can be subject to significant change. New laws and requirements pose increasingly complex compliance challenges and could potentially elevate our costs. Any failure or perceived failure to comply with these laws and regulations could result in significant penalties, legal liability, judgments, and negative publicity, changes in our business practices, and adverse impacts to our business. We continue to monitor and assess the impact of these laws, such as the California Consumer Privacy Act and the Cyber Incident Reporting for Critical Infrastructure Act, and other similar legislation. If we are not able to adjust to changing laws, regulations, and standards relating to privacy or cybersecurity, our business may be materially harmed. As noted above, we are also subject to the possibility of cyber events, which themselves may result in a violation of these privacy and data security laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable privacy and cybersecurity laws, we may incur significant liabilities and penalties as a result.

Changes in U.S. foreign trade policies, including the imposition of additional tariffs and other trade barriers, and efforts to withdraw from or materially modify international trade agreements, may materially and adversely affect our business, operations and financial condition.

U.S. foreign trade policy continues to evolve, and recent actions have resulted in the imposition of new and increased tariffs, as well as other trade barriers on the foreign import of certain materials and products. For example, in April 2025, the U.S. government announced a new tariff regime that included a 10% baseline tariff on most products imported from other countries and an additional individualized reciprocal tariff on the countries with which the U.S. has the largest trade deficits, including China. Since that time, the U.S. has expanded tariffs on key industrial inputs, including tariffs on steel and aluminum imports, and has at times announced, rescinded, modified and temporarily suspended multiple tariffs on several foreign jurisdictions, which has increased uncertainty regarding the ultimate effect of the tariffs on economic conditions. Additionally, in August 2025, the U.S. Court of Appeals for the Federal Circuit ruled that many of the tariffs imposed under the Trump Administration exceed presidential authority and therefore are invalid, and in February 2026, the U.S. Supreme Court affirmed such decision. Following the ruling, the Trump Administration signed an executive order imposing a 10% “global tariff” and later indicated an intention to increase such “global tariff” to 15%, effective immediately, using presidential powers under certain U.S. trade laws. If implemented, such tariffs can remain in effect for up to 150 days, which may be extended by the U.S. Congress. The Trump Administration may continue to impose additional tariffs under other U.S. trade laws. Moreover, from time to time, certain leaders in the U.S. government, including in the Trump administration, have indicated a willingness to revise, renegotiate or terminate various existing bilateral and multilateral trade agreements. The uncertainty over such policies has caused volatility in commodity, capital and financial markets, increased concerns over domestic and global inflation and adversely impacted consumer confidence in the U.S. and worldwide. Tariffs or other trade restrictions may lead to continuing uncertainty and volatility in U.S. and global financial and economic conditions and commodity markets, declining consumer confidence, significant inflation and diminished expectations for the economy, and ultimately reduced demand for oil and natural gas.

Changes in tariffs and trade restrictions can be announced with little or no advance notice. We cannot predict what additional changes to trade policy or tariffs will be made by the Trump administration or Congress, including whether existing tariff policies will be maintained or modified, what materials or products may be subject to such policies or whether the entry into new bilateral or multilateral trade agreements, or the amendment or termination of existing trade agreements, will occur, nor can we predict the effects that any such changes would have on our business. However, such steps, if adopted, could increase our costs, disrupt supply chains, delay project timelines or otherwise adversely impact our business and operations.

In addition, changes in U.S. trade policy and tariffs have resulted, and could again result, in reactions from U.S. trading partners, including adopting responsive trade policies. For example, in response to the U.S. government's additional tariff on imports from China, on February 4, 2025, the Chinese government announced that it would implement tariffs on certain goods being imported into China from the U.S. Similar responsive measures have been announced or implemented by other countries affected by U.S. trade actions. There can be no assurance that such changes in U.S. or foreign trade policy or tariffs or in laws and policies governing foreign trade, and any resulting negative sentiments or retaliatory trade practices towards the United States as a result of such changes, would not materially and adversely affect our business, financial condition and results of operations.

Risks Related to Our Relationship with Banpu and its Affiliates

Banpu is our controlling stockholder and exercises a significant influence over us, and investors' ability to influence matters requiring stockholder approval may be limited.

As of February 27, 2026, Banpu indirectly owns approximately 67.6% of our outstanding common stock. Our outstanding common stock is entitled to one vote per share. As a result of this ownership, Banpu has a significant influence on our affairs and its voting power constitutes a significant majority 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, under our Stockholders' Agreement, as long as BNAC beneficially owns 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 September 27, 2025 until the first date on which BNAC beneficially owns 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (ii) from and after the first date on which BNAC beneficially owns 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.

Further, if any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of our equity interests, or if any person or group acquires a greater percentage of our equity interests than are then held by Banpu and its controlled affiliates (excluding portfolio companies and operating companies of Banpu), such event will be an event of default under the RBL Credit Agreement, which may result in the amounts owed by us thereunder to become immediately due and payable. Further, if, any person or group (other than Banpu and its controlled affiliates) acquires more than 50% of our equity interests, unless Banpu and its controlled retain the right to appoint a majority of the directors of BKV Upstream Midstream, and Moody's or S&P decreases their rating of the 2030 Senior Notes as a result thereof within 60 days, holders of the 2030 Senior Notes will be entitled to a require BKV Upstream Midstream to repurchase all or any part of that holder's 2030 Senior Notes pursuant to an offer on the terms set forth in the indenture governing the 2030 Senior Notes.

Banpu also exercises significant influence over the BKV-BPP Cotton Cove Joint Venture and the BKV-BPP Power Joint Venture, each of which requires the consent of BPPUS for certain material actions. The BKV-BPP Cotton Cove Joint Venture is controlled by its six-member board of managers, four of whom are appointed by BKV dCarbon Ventures (our wholly-owned subsidiary) and two of whom are appointed by BPPUS. Of the three members appointed by us, none are employees of Banpu who also serve on our board of directors. For additional information, see "*— Risks Related to Our CCUS Business — We operate the Cotton Cove Project through a joint venture that requires the consent of BPPUS for certain material actions.*"

The BKV-BPP Power Joint Venture is controlled by its twelve-member board of managers (the "Power JV Board"), nine of whom are appointed by us and three of whom are appointed by BPPUS. For as long as BPPUS maintains an ownership interest in the BKV-BPP Power Joint Venture of at least 10%, consent from at least one member of the Power JV Board appointed by BPPUS will be required for certain specified actions as detailed in the BKV-BPP Power LLC Agreement. For additional information, see "*— Risks Related to Our Power Generation Business — We operate our power generation business through a joint venture that requires the consent of BPPUS for certain material actions.*"

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, and results of operations. In addition, Banpu's control or significant influence over us may have an adverse effect on the price of our common stock.

Historically, we 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 our IPO on September 27, 2024, we relied on Banpu and its affiliates for the capital investments necessary to fund our business through loan proceeds and other contributions. Following this date, Banpu and its affiliates 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 RBL Credit Agreement. We expect to fund the majority of our CCUS business from a variety of external sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. Our future operating performance and ability 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. Banpu continues 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 are currently a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for and rely on exemptions from certain corporate governance requirements.

Banpu beneficially controls a significant majority of the voting power of our outstanding voting stock. Pursuant to our Stockholders' Agreement, BNAC, through ownership interests in us held by BNAC, has certain rights to designate individuals for nomination to our board of directors. 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. Accordingly, the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements are not afforded to our stockholders.

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 our status as a publicly traded company;
- employee retention and recruiting;
- corporate opportunities that may be attractive to both Banpu and us;

• the arrangements governing the BKV-BPP Power Joint Venture, BKV-BPP Cotton Cove 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 and significantly influenced by Banpu, we may not have the leverage to negotiate amendments to the arrangements governing the BKV-BPP Power Joint Venture or BKV-BPP Cotton Cove Joint Venture (if any are required) on terms as favorable to us as those we would negotiate with an unaffiliated third party. As a result of Banpu's relationship with us, Banpu will have significant influence over our affairs and potentially those of the BKV-BPP Power Joint Venture and could exercise such influence in a manner that is not in the best interests of our stockholders.

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. 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 due to the fact that any such person pursues or acquires any corporate opportunity for, or recommends or transfers any corporate 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. In addition, Christopher Kalnin serves as a member of Banpu's Executive Committee with responsibilities to Banpu to, among other things, manage all aspects of Banpu's business in North America. Although our corporate opportunity policy requires Mr. Kalnin to present applicable business opportunities sourced by him to our Company before such opportunities may be presented to Banpu, Banpu or its affiliates may compete with us for acquisition or other business opportunities.

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

Christopher Kalnin currently serves as a member of Banpu's Executive Committee with responsibilities to Banpu to, among other things, manage all aspects of Banpu's business in North America. Seven of our directors are employees of Banpu or its affiliates. In addition, most of our directors now own, or our officers and other directors may own in the future, capital stock or equity awards in Banpu or its affiliates. For certain of these individuals, their holdings of common stock or equity awards in Banpu or its affiliates 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 or its affiliates 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 of 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.

The BKV-BPP Joint Venture Transaction is a related party transaction, which may create actual or perceived conflicts of interest.

The BKV-BPP Joint Venture Transaction is considered a “Related Party” transaction pursuant to Rule 312.03 of the NYSE Listed Company Manual. BPPUS is a wholly-owned subsidiary of Banpu Power, which is a subsidiary of Banpu, and Banpu is the ultimate parent company of both BKV and BKV’s majority stockholder, BNAC. Although our board of directors implemented procedural safeguards, including the formation of a special committee consisting solely of independent and disinterested directors, these overlapping relationships may create the perception that the BKV-BPP Joint Venture Transaction was not negotiated at arm’s length. Such perceptions could lead to negative stockholder sentiment, potential claims, or increased regulatory scrutiny.

Risks Related to 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 Item 1A, “*Risk Factors*,” and under “*Cautionary Note Regarding Forward-Looking Statements*” included elsewhere herein. Many of these risks and uncertainties are beyond our control, such as declines in commodity prices, the speculative nature of estimating natural gas and NGL reserves, and 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 do not currently plan to, and may not in the future have sufficient available cash to, pay dividends on our common stock.

We do not currently plan to declare dividends on our shares of common stock, and any future determination to pay dividends will be made at the sole discretion of our board of directors after considering our general economic and business conditions, including, among other things, our financial condition and anticipated cash needs. Furthermore, 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. Events may occur, including a reduction in anticipated production volumes or realized prices or other events, which could materially impact the amount of surplus we may have and/or may result in insufficient available cash to enable us to pay dividends to our stockholders.

The payment of dividends on our common stock is subject to the discretion of our board of directors and the lack of dividend payments on our common stock could adversely affect the market price of our common stock.

Our stockholders will have no contractual or other legal right to dividends. The payment of any 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. 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 insufficient cash available for payment of dividends on our common stock. The lack of dividend payments on our common stock could adversely affect the market price of our common stock.

The repurchase of shares of our common stock will be at the discretion of management and subject to numerous factors.

In December 2025, our board of directors authorized a two-year share repurchase program pursuant to which the Company may repurchase from time to time shares of its common stock, for an aggregate purchase price of up to $100.0 million through open market purchases, block trades, 10b5-1 plans, or by means of privately negotiated purchases. However, the timing and total amount of any share repurchases will be determined at the discretion of management based on a variety of factors, including economic and market conditions, the stock price, the Company's liquidity requirements and priorities, regulatory requirements, applicable legal requirements and other factors. The repurchase program does not obligate us to repurchase any specific number of shares and may be suspended, modified, or discontinued at any time at the discretion of our board of directors.

The agreements governing our indebtedness impose restrictions on dividend payments.

The RBL Credit Agreement and the indenture governing the 2030 Senior Notes contain, and any future debt agreement may contain, covenants that prohibit us from paying dividends on our common stock under certain circumstances. The RBL Credit Agreement permits BKV Upstream Midstream and its restricted subsidiaries to pay (a) dividends to their stockholders (including to BKV Corporation) in an amount not to exceed 100% of Distributable Free Cash Flow (as defined in the RBL Credit Agreement) if (1) the net leverage ratio on a pro forma basis is less than or equal to 2.00 to 1.00 and (2) the pro forma available commitments are greater than or equal to 20% of the Loan Limit, and (b) additional unlimited dividends to their stockholders (including to BKV Corporation) if (1) the net leverage ratio (as defined in the RBL Credit Agreement) on a pro forma basis is less than or equal to 1.75 to 1.00 and (2) the pro forma available commitments are greater than or equal to 25% of the Loan Limit (as defined in the RBL Credit Agreement), in each case, subject to no default, event of default or borrowing base deficiency under the RBL Credit Agreement. The indenture governing the 2030 Senior Notes permits BKV Upstream Midstream and its restricted subsidiaries to pay (a) unlimited dividends to their stockholders (including to BKV Corporation) if (1) the consolidated net leverage ratio (as defined in the indenture governing the 2030 Senior Notes) on a pro forma basis is less than or equal to 1.00 to 1.00 and (2) other dividends to their stockholders (including to BKV Corporation) in an amount not to exceed 25.0% of BKV Upstream Midstream's Consolidated EBITDAX (as defined in the indenture governing the 2030 Senior Notes) for the most recently ended four full fiscal quarters, so long as, after giving pro forma effect to the payment of any such dividend, the consolidated net leverage ratio is no greater than 1.25 to 1.00, in each case, subject to no default or event of default under the indenture governing the 2030 Senior Notes. There can be no assurance that we will generate sufficient cash flow to permit us to reduce leverage and pay dividends in compliance with the RBL Credit Agreement, the indenture governing the 2030 Senior Notes, 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.

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

As of December 31, 2024, a material weakness existed in our internal control over financial reporting. 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 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. This material weakness resulted in audit adjustments to income tax benefit, income taxes payable to related party, and deferred tax assets and liabilities in the consolidated financial statements as of December 31, 2021 and for the year then ended.

During the year ended December 31, 2025, we remediated this material weakness related to the accounting for our income taxes primarily by designing and implementing additional internal controls, including those related to 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 addressed the internal control deficiencies that led to this material weakness, the measures we have taken may not be effective.

The material weaknesses described above could have resulted 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.

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 guarantee 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 as a public entity. 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 common stock.

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 66 ⅔% 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 66 ⅔% 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 our sponsor, Banpu, and its affiliates, 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. Banpu is the ultimate parent company of BPPUS and BNAC and, as a result, Banpu's concentration of stock ownership increased upon the issuance of 5,315,390 shares of common stock issued to BPPUS in connection with the closing of the BKV-BPP Power Joint Venture Transaction. 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.

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.

As of February 27, 2026, Banpu, the ultimate parent of BPPUS and BNAC, is the indirect beneficial owner of 69,193,004 shares of common stock, representing approximately 67.6% of our total outstanding common stock, and management, directors, and other employee and non-employee stockholders, collectively, own 33,095,073 shares of common stock, representing approximately 32.4% of our total outstanding common stock.

In addition, our Stockholders’ Agreement provides 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. In accordance with the registration rights granted to BNAC, on October 1, 2025, we filed a resale registration statement on Form S-3 to register the offer and sale of 63,877,614 shares of common stock owned by BNAC, and subsequently amended the resale registration statement on November 25, 2025. As of the date of this Annual Report on Form 10-K, no shares of our common stock have been sold by BNAC pursuant to that resale registration statement.

In connection with the closing of the Bedrock Acquisition, we entered into a Registration Rights Agreement with Bedrock Energy Partners, LLC ("Bedrock Energy Partners"), pursuant to which we agreed to, among other things, provide

Bedrock Energy Partners with certain demand and piggyback registration rights for the 5,233,957 shares of common stock received in the Bedrock Acquisition, subject to customary cutbacks, blackout periods, and other limitations.

In accordance with the registration rights granted to Bedrock Energy Partners, on December 23, 2025, we filed an automatic shelf registration statement on Form S-3 to register the offer and sale of 5,233,957 shares of our common stock owned by Bedrock Energy Partners. As of the date of this Annual Report on Form 10-K, no shares of our common stock have been sold by Bedrock Energy Partners pursuant to that resale registration statement.

In connection with the closing of the BKV-BPP Power Joint Venture Transaction, we also entered into a Registration Rights Agreement with BPPUS, pursuant to which BPPUS received certain demand and piggyback registration rights for the 5,315,390 shares of common stock issued to BPPUS in the BKV-BPP Power Joint Venture Transaction, subject to a 180-day lock-up and customary cutbacks, blackout periods and other limitations.

We also may, in the future, issue additional shares of common stock as some or all of the consideration for future transactions. Furthermore, we may issue additional shares of common stock or convertible securities in subsequent public offerings. 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 of our common stock will have on the market price of our common stock. Issuances of substantial amounts of our common stock or sales of shares owned by Banpu and other stockholders, or the perception that such issuances or sales could occur, may adversely affect prevailing market prices of our common stock.

Our common stock does not entitle the holders thereof 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 or the issuance of preferred stock 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 is not subject to conversion, redemption or sinking fund provisions.

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 designates 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 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 Delaware General Corporation Law 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, and cash flows.

The price of our common stock has fluctuated substantially and may fluctuate substantially in the future.

The market price of our common stock has experienced volatility and may fluctuate significantly in response to a number of factors, many of which we cannot predict or control, including supply of and demand for natural gas and NGLs and the prices of natural gas and NGLs, the level of global drilling, exploration and production activities, general market and economic conditions, disruptions, downgrades, credit events and perceived problems in the credit markets; actual or anticipated variations in our operating results; changes in our investments or asset composition; write-downs or perceived credit or liquidity issues affecting our assets; market perception of our business and our assets; reports by industry analysts; changes in our financial guidance or negative announcements by our customers, competitors or suppliers regarding their own performance; our level of indebtedness or adverse market reaction to any indebtedness that we may incur in the future; our ability to raise capital on favorable terms or at all; loss of any major funding source; additions or departures of our executive officers or key personnel; changes in market valuations of similar companies; and speculation in the press or investment community.

Securities markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. Any broad market fluctuations may adversely affect the trading price of our common stock.

Our ability to utilize U.S. net operating loss and Section 163(j) carryforwards to reduce future U.S. taxable income could be limited.

We and our subsidiaries have U.S. NOL and Section 163(j) interest expense carryforwards for U.S. federal income tax purposes. Our ability to utilize such NOL and Section 163(j) interest expense carryforwards would be limited under Section 382 of the Code ("Section 382"), if we experience an "ownership change," which generally will occur if the direct or indirect ownership of our stock by one or more stockholders or groups of stockholders that are deemed to own at least 5% of our stock cumulatively increases by more than 50 percentage points at any time during a rolling three-year period. As of December 31, 2025, we do not believe that our NOL and Section 163(j) interest expense carryforwards are currently subject to the limits of Section 382. However, future issuances of our stock or the capital stock of Banpu and other sales or exchanges of our stock or the capital stock of Banpu could trigger an ownership change and, thus, a limitation on our ability to utilize NOL carryforwards under Section 382. Such limitation could result in an increase in our U.S. federal income tax liability.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Our processes are designed to identify, assess, and manage cybersecurity risks that could be material to the Company, including risks that could compromise sensitive information, disrupt data or systems, or jeopardize the security of facilities and infrastructure, including third-party processing plants and pipelines.

Managing Material Risks & Integrated Overall Risk Management

We have strategically integrated cybersecurity risk management into our broader enterprise risk management framework to promote a company-wide culture of cyber risk awareness. Our cybersecurity risk management program is supported by a senior technology advisor and the Senior Director of Cybersecurity who work closely with our information technology ("IT") department to continuously evaluate and address cybersecurity risks in alignment with business objectives, operational needs, and industry-accepted standards, such as the Center for Internet Security (CIS) Critical Security Controls, National Institute of Standards and Technology (NIST) frameworks, and the North American Electric Reliability Corporation (NERC) standards.

We have processes and procedures in place to monitor the prevention, detection, mitigation, and remediation of cybersecurity risks. These include but are not limited to:

- Maintaining and regularly updating a defined and practiced incident response plan (“IRP”);
- Maintaining cyber insurance coverage;
- Employing appropriate incident prevention and detection software, such as antivirus, anti-malware, firewall, endpoint detection, and identity and access management;
- Executing scheduled, recurring server and infrastructure vulnerability management and patching processes;
- Maintaining a defined disaster recovery policy with backup/disaster recovery software;
- Educating, training, and testing employees on information security practices and identification of potential cybersecurity risks and threats; and
- Ensuring familiarity and compliance with cybersecurity frameworks.

Engaging Third Parties on Risk Management

Recognizing the complexity and evolving nature of cybersecurity risk, we engage with external experts, including, but not limited to, the Cybersecurity Operations Center (“CSOC”) team to evaluate, monitor, and test our cyber management systems, and to respond to cyber risks. Our third-party CSOC team provides 24-hour monitoring to detect and respond to suspicious activity in real time. Our collaboration with third parties includes audits, threat and vulnerability assessments, IRP testing, company-wide monitoring of cybersecurity risks, and consultation on security enhancements. Third-party experts have assisted us in conducting cross-functional tabletop exercises, IT and operational technology network penetration assessments, and periodically scheduled cybersecurity risk discussions to develop comprehensive identified vulnerability remediation plans.

Managing Third Party Risk

Our cybersecurity approach assesses and manages the risks associated with the use of vendors, service providers, and other third parties that provide information system services, process information on our behalf, or have access to our information systems. BKV maintains ongoing monitoring to support continuous compliance with our cybersecurity standards and requirements, and regularly updates and patches third-party applications and tools when vulnerabilities are discovered.

Risks from Cybersecurity Incidents

As of March 6, 2026, we have not experienced any material cybersecurity incidents and we are not aware of any cybersecurity risks that are reasonably likely to materially affect the Company, its operations, or financial standing. For additional information about cybersecurity risks associated with our business, see Item 1A, “*Risk Factors*.”

Governance

Risk Management Personnel

We have an enterprise risk committee that includes our executive leadership team and other senior members within our legal, IT, finance and accounting, and operational departments, which oversees our operational, strategic, and corporate-level risks, including risk management.

Our comprehensive cybersecurity risk management is led by a senior technology advisor, who brings over 40 years of extensive experience in information technology and over 35 years in the oil and gas industry leading large, complex global technology operating environments. The senior technology advisor works closely with executive management and the Senior Director of Cybersecurity to provide strategic oversight and guidance on cybersecurity risk management. The senior technology advisor and Senior Director of Cybersecurity, who brings over 30 years of cybersecurity and compliance experience in the oil and gas and mining industries as a Certified Information Systems Security Professional (CISSP) and Certified Information Systems Auditor (CISA) in large complex global information technology operating environments, play key roles in assessing, monitoring, and managing the Company's cybersecurity risks. The senior technology advisor and Senior Director of Cybersecurity are supported by our IT department and CSOC. These stakeholders meet monthly to review the current risk trends, vulnerability and threat landscape, improvement programs, and an overall baseline scorecard over our cybersecurity risk. Our cybersecurity team continually conducts extensive reviews of our systems, networks, and data infrastructure to identify potential cybersecurity threats and vulnerabilities and implements systems and tools to remediate perceived risks. These tools are designed to prevent and detect activities or events that could pose a cybersecurity risk to our business and also enable the Company to quickly respond and recover from any potential cybersecurity event.

Monitor Cybersecurity Incidents

The senior technology advisor and Senior Director of Cybersecurity are continually informed and updated about the latest developments in cybersecurity, including emerging threats and innovative risk management techniques. Through the aid of the Company's CSOC, processes are implemented for 24/7/365 monitoring of our information systems and ongoing cybersecurity threat assessment. The deployment of advanced security measures, regular system audits to identify potential vulnerabilities, and periodic cyber assessment exercises support these programmatic efforts. In the event of a cybersecurity incident, the Company is equipped with a defined and practiced IRP. This plan includes immediate actions to mitigate the impact and long-term strategies for remediation and prevention of future incidents.

Board of Director Oversight

Our Audit & Risks Committee provides oversight of cybersecurity risk in connection with BKV's comprehensive cybersecurity strategy and receives regular quarterly updates on our ongoing assessment of cybersecurity risks, threats, and data security programs to prevent and detect breaches and attacks against us. The senior technology advisor and other experts, as necessary, provide the Audit & Risks Committee quarterly cybersecurity updates and risk discussions that encompass a broad range of topics, including but not limited to:

- Current cybersecurity threat landscape and emerging threats;
- Status of ongoing cybersecurity initiatives and strategies;
- Incident reports and learnings from unique cybersecurity events, including those of other companies;
- Compliance status and efforts with regulatory requirements and industry standards; and
- Benchmarked data on the performance of certain aspects of our cybersecurity program relative to our peers.

The Audit & Risks Committee meets quarterly to discuss areas that are potentially high risk to the Company.

ITEM 2. PROPERTIES

Information regarding our properties is included in Item 1. "*Business*" and in *Note 20 - Supplemental Oil and Gas Disclosures (unaudited)* incorporated herein.

ITEM 3. 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.

The information with respect to this Item 3. "*Legal Proceedings*" is set forth in Item 8 of Part II, *Financial Statements and Supplementary Data*, in *Note 16 - Commitments and Contingencies* incorporated herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Common Stock and Shareholders

Our common stock is traded on the NYSE under the symbol “BKV.” Our common stock has been trading on the NYSE since September 26, 2024. Prior to trading on the NYSE, there was no established public trading market for our common stock.

On February 27, 2026, the closing price of our common stock was $31.33 and we had approximately 50 stockholders of record, excluding stockholders for whom shares are held in “nominee” or “street” name.

Dividends

We currently do not pay a fixed cash dividend to holders of our common stock. Our dividend policy is under consideration by our board of directors. Any future determination related to our dividend policy will be made at the sole discretion of our board of directors after considering our general economic and business conditions, including 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.

Securities Authorized for Issuance Under Equity Compensation Plans

Information required by this item is incorporated by reference to our 2026 Proxy Statement, as defined in Part III, Item 10 of this Annual Report on Form 10-K.

Issuer Purchases of Equity Securities

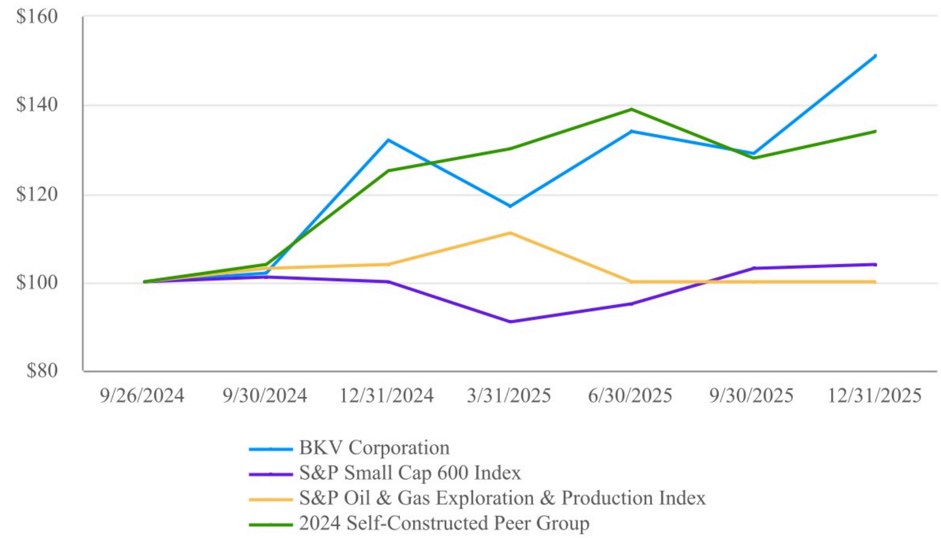
On December 18, 2025, our board of directors authorized a two-year share repurchase program (the "Share Repurchase Program"), pursuant to which we may repurchase, from time to time, shares of our common stock for an aggregate purchase price of up to $100.0 million through open market purchases, block trades, 10b5-1 plans, or by means of privately negotiated purchases, in each case subject to compliance with the applicable provisions of federal and state securities laws and regulations, including Rule 10b-18 under the Exchange Act.

The timing and total amount of any share repurchases will be determined at the discretion of our management based on a variety of factors, including economic and market conditions, the stock price, our liquidity requirements and priorities, regulatory requirements, applicable legal requirements, and other factors. The repurchase program does not obligate us to repurchase any specific number of shares and may be suspended, modified, or discontinued at any time at the discretion of our board of directors. Share repurchases are expected to be funded through available cash or borrowings under our existing reserve-based lending agreement. We made no purchases of common stock under the Share Repurchase Program during the three and twelve months ended December 31, 2025.

Stock Performance Graph

The following Performance Graph and related information shall not be deemed “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filings under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate it by reference into such filings.

The performance graph below illustrates changes over the period of September 26, 2024 through December 31, 2025, in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S&P Small Cap 600, the S&P Oil & Gas Exploration and Production Index, and a customized peer group. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from September 26, 2024 through December 31, 2025.



	9/26/2024	9/30/2024	12/31/2024	3/31/2025	6/30/2025	9/30/2025	12/31/2025
BKV Corporation	$ 100	$ 102	$ 132	$ 117	$ 134	$ 129	$ 151
S&P Small Cap 600	100	101	100	91	95	103	104
S&P 1500 Oil & Gas Exploration & Production	100	103	104	111	100	100	100
Self-Constructed Peer Group [(1)]	100	104	125	130	139	128	134

[(1)] The Self-Constructed Peer Group includes the following companies: EQT Corporation, Range Resources Corporation, Gulfport Energy Corporation, Expand Energy Corporation, and CNX Resources Corporation.

ITEM 6. [RESERVED]

ITEM 7. 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 consolidated financial statements and related notes included in Item 8 of Part II, Financial Statements and Supplementary Data in this Annual Report on Form 10-K. This Annual Report on Form 10-K contains certain statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Certain statements contained in the Management's Discussion and Analysis of Financial Condition and Results of Operations are forward-looking statements that involve risks and uncertainties. The forward-looking statements are not historical facts, but rather are based on current expectations, estimates, assumptions, and projections about our industry, business, and future financial results. Our actual results could differ materially from the results contemplated by these forward-looking statements due to a number of factors, including those discussed in other sections of this Annual Report on Form 10-K. See Item 1A of Part I, "Risk Factors" and under "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are a forward-thinking, growth-driven energy company focused on creating long-term risk-adjusted stockholder value through the development of natural gas producing assets, the ownership and operation of natural gas-fired power generation assets, and selective accretive acquisitions. Our core businesses are the production of natural gas and the generation of natural gas-fired power from our owned and operated assets, supported by a closed-loop strategy enabled by our upstream, midstream, power, and CCUS businesses.

Our operations are supported by four business lines: natural gas production, natural gas midstream, power generation, and CCUS. Our operating approach is designed around a closed-loop model that aligns these business lines to support cost efficiency, commercial optimization, and operational reliability across the value chain. Through this approach, we retain operational control over the production, transportation, and processing of natural gas and provide multiple platforms for disciplined capital deployment, while meeting growing demand for low carbon natural gas and power.

For example, in the Barnett Shale, natural gas produced from our upstream assets is gathered and transported in part through our midstream systems. In November 2023, we commenced sequestration operations at our first CCUS project, and we currently expect our second and third CCUS projects to commence sequestration activities in the first and second quarter of 2026 with additional CCUS growth opportunities beyond 2026. Further, we are pursuing a power growth strategy that aligns with both our natural gas and CCUS businesses.

As part of our ongoing operations, we expect our owned and operated upstream and natural gas midstream businesses to achieve net-zero Scope 1 and Scope 2 greenhouse gas emissions during the early 2030s and net-zero Scope 1, Scope 2, and Scope 3 emissions by the late 2030s.

We believe our business model, experienced management team, and disciplined technology-enabled operations support our ability to create long-term, risk-adjusted stockholder value.

Recent Developments

- **Equity Offering**. On December 3, 2025, we completed an underwritten public offering of 6,900,000 shares of common stock for net proceeds of $170.1 million (the "2025 Equity Offering"). We used the net proceeds from the 2025 Equity Offering to fund the cash consideration for the BKV-BPP Power Joint Venture Transaction and related expenses. For additional information, see *Note 1 - Business and Basis of Presentation* and *Note 13 - Stockholders' Equity and Mezzanine Equity*.
- **BKV-BPP Power Joint Venture Transaction.** On January 30, 2026, we completed the previously announced BKV-BPP Power Joint Venture Transaction for aggregate consideration consisting of $115.1 million in cash and 5,315,390 shares of our common stock. We funded the cash consideration with a combination of cash on hand and the net proceeds from the 2025 Equity Offering. Following the closing of the transaction, the BKV-BPP Power Joint Venture is owned 75% by BKV and 25% by BPPUS, and the financial results of BKV-BPP Power will be consolidated into our financial statements. For additional information, see *Note 14 - Investments* and *Note 19 - Subsequent Events*.

Operational and Financial Highlights

Below are some highlights of our operating and financial results for the year ended December 31, 2025.

- Production of natural gas, NGLs, and oil was 305.0 Bcfe, or 835.5 MMcfe/d.
- Average realized product prices, excluding the impact of settled derivatives, were $2.81 per Mcfe.

- Production revenues were $857.6 million and midstream revenues were $10.5 million.
- Lease operating expense was $145.6 million, or $0.48 per Mcfe.
- Net income attributable to BKV was $173.1 million.
- Net cash provided by operating activities was $242.7 million.
- Accrued capital expenditures were $318.5 million.

Factors That Affect Comparability of Our Financial Condition and Results of Operations

Our business depends on many factors, primarily commodity prices, market supply and demand for natural gas, NGLs, and oil, upstream capital costs, and production costs. We continually monitor domestic and global factors which may cause our actual results of operations to differ from historical results or expected outlook.

Commodity Pricing. The natural gas and NGL industry is cyclical and commodity prices are highly volatile, and we expect these prices to continue to remain volatile in the near future. In order to manage our market exposure of price volatility, we utilize derivative contracts in connection with our natural gas operations to provide an economic hedge of our exposure to commodity price risks associated with anticipated future natural gas and NGL production. However, there are still market risks beyond our control that may impact our financial condition, results of operations, and cash flows.

Supply, Demand, Market Risk, and the Impact on Natural Gas, NGLs, and Oil 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 level of drilling, completion, and production activities by other natural gas production companies, global industry-wide supply chain disruptions, widespread shortages of labor, material, and services, the ability to agree and maintain production levels by members of OPEC and other oil producing countries, and political instability of other energy producing countries, 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.

Upstream Capital Costs. 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.

Production Volumes.

The following table presents our historical production volumes for the periods presented:

	Year Ended December 31,		
	2025	2024	2023
Production Data			
Natural gas (MMcf)	242,935	228,682	249,766
NGLs (MBbls)	10,181	9,858	10,554
Oil (MBbls)	159	96	119
Total volumes (MMcfe)	304,975	288,406	313,804
Average daily total volumes (MMcfe/d)	835.5	788.0	859.7

Impact of Acquisition and Joint Venture Transactions. Our financial condition and results of operations for the periods presented were impacted by acquisitions and joint venture transactions completed during 2025, which changed the scale, composition, and ownership structure of our operations.

In May 2025, as part of our CCUS business strategy, we partnered with the Class B Member to form the BKV-CIP Joint Venture, and beginning in the third quarter of 2025, we consolidated the BKV-BPP Cotton Cove Joint Venture. These transactions resulted in changes to the accounting treatment of certain assets and results, including the recognition of noncontrolling interests and fair value adjustments, further affecting comparability across periods.

In September 2025, we completed the Bedrock Acquisition, with an economic effective date of July 1, 2025. The acquisition significantly expanded our asset base in the Barnett with low-decline proved developed producing reserves, resulting in higher production volumes, revenues, operating expenses, depreciation, depletion and amortization, and asset retirement obligations beginning in the third quarter of 2025. Because the acquired assets were not owned for a full period, results for 2025 are not comparable to prior periods. In addition, the consideration paid, including cash, common stock, and repayment of indebtedness, affected our liquidity, leverage, and weighted-average shares outstanding.

As a result of these transactions, our historical operating, financial, and reserve data may not be comparable between periods presented in this Annual Report on Form 10-K.

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.

Realized Commodity Prices

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. For further discussion on our derivative contracts, see *Note 7 - Derivative Instruments* in Item 8 of Part II, "*Financial Statements and Supplementary Data.*" The following is a comparison of average pricing excluding and including the effects of derivatives:

	Year Ended December 31, 2025	2024	2023
Average prices			
Natural gas ($/Mcf)			
Average NYMEX Henry Hub price	$ 3.43	$ 2.27	$ 2.74
Average natural gas realized price (excluding derivatives)	$ 2.78	$ 1.69	$ 2.04
Average natural gas realized price (including derivatives) (1)	$ 2.75	$ 2.10	$ 2.23
Differential	$ (0.65)	$ (0.58)	$ (0.70)
NGLs ($/Bbl)			
Average NGL realized price (excluding derivatives)	$ 17.00	$ 16.79	$ 17.80
Average NGL realized price (including derivatives) (1)	$ 16.84	$ 17.19	$ 17.55
Oil ($/Bbl)			
Average oil realized price	$ 59.50	$ 68.81	$ 70.97
High and low daily spot prices			
Oil ($/Bbl)			
High NYMEX WTI	$ 80.73	$ 87.69	$ 93.67
Low NYMEX WTI	$ 55.44	$ 66.73	$ 66.61
Natural gas ($/Mcf)			
High NYMEX Henry Hub	$ 9.86	$ 13.20	$ 3.78
Low NYMEX Henry Hub	$ 2.65	$ 1.21	$ 1.74

(1) Impact of derivatives prices excludes $13.3 million and $46.7 million of gains on derivative contract terminations for the years ended December 31, 2024 and 2023, respectively.

Results of Operations

Comparison of the Year Ended December 31, 2025 and 2024

Operating Revenues and Operating Income

Our operating revenues and other income from operations include the revenues from the sale of natural gas, NGLs, and oil, midstream revenues, gains and losses on our derivative contracts and on the sales of our business and assets, marketing revenues, Section 45Q tax credits, related party revenues, and other income from operations. The following table provides information on our revenues and other operating income for the periods presented:

(in thousands, other than percentages)	Year Ended December 31, 2025	2024	$ Change	% Change
Revenues				
Natural gas revenues	$ 675,078	$ 385,456	$ 289,622	75 %
NGL revenues	173,059	165,508	7,551	5 %
Oil revenues	9,460	6,606	2,854	43 %
Midstream revenues	10,456	12,560	(2,104)	(17)%
Derivative gains (losses), net	105,081	(34,152)	139,233	*
Marketing revenues	12,304	10,668	1,636	15 %
Gain on sale of business	—	7,080	(7,080)	(100)%
Gains (losses) on sales of assets, net	(1,805)	3,523	(5,328)	*
Section 45Q tax credits	11,752	14,021	(2,269)	(16)%
Related party revenues	1,760	3,080	(1,320)	(43)%
Other	11,664	6,631	5,033	76 %
Total revenues and other operating income	$ 1,008,809	$ 580,981		

**Percentage not meaningful*

Natural Gas Revenues

Our natural gas revenues increased by $289.6 million, or 75%, to $675.1 million for the year ended December 31, 2025, from $385.5 million for the year ended December 31, 2024. The impact of commodity price increases, excluding the effect of derivative settlements, provided a $265.6 million increase in year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes). The increase was also due to higher production volumes during the year ended December 31, 2025, which accounted for a $24.0 million increase in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price).

NGL Revenues

Our NGL revenues increased by $7.6 million, or 5%, to $173.1 million for the year ended December 31, 2025, from $165.5 million for the year ended December 31, 2024. The increase was due to higher production volumes during the year ended December 31, 2025, which accounted for a $5.5 million increase in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The increase was also due to the impact of commodity price increases, excluding the effect of derivative settlements, which accounted for a $2.1 million increase in year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes).

Oil Revenues

Our oil revenues increased by $2.9 million, or 43%, to $9.5 million for the year ended December 31, 2025, from $6.6 million for the year ended December 31, 2024. The increase was due to higher production volumes during the year ended December 31, 2025, which accounted for a $4.4 million increase in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The increase was offset by the impact of commodity price decreases, excluding the effect of derivative settlements, which accounted for a $1.5 million decrease in the year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes).

Midstream Revenues

Our midstream revenues decreased by $2.1 million, or 17%, to $10.5 million for the year ended December 31, 2025, from $12.6 million for the year ended December 31, 2024. This decrease was primarily due to the divestiture of Chaffee of $2.0 million as we sold our Repsol Midstream Interest in connection with this sale.

Derivative Gains (Losses), Net

For the year ended December 31, 2025, we had net realized and unrealized gains on derivative contracts of $105.1 million compared to net realized and unrealized losses on derivative contracts of $34.2 million for the year ended December 31, 2024. The increase in gains for the year ended December 31, 2025 was primarily attributable to our open derivative positions, which were in more of an unrealized gain position of $113.2 million, compared to an unrealized loss position of $146.7 million for the year ended December 31, 2024, The increase in unrealized gains for the year ended December 31, 2025 reflected decreases in the forward curve of natural gas prices relative to December 31, 2024, whereas the prior year period reflected increases in the forward curve of natural gas prices compared to December 31, 2023. The increased gains on our derivative contracts were also offset by realized losses of $8.1 million during the year ended December 31, 2025, compared to realized gains of $112.5 million during the year ended December 31, 2024, which were due to higher natural gas prices settled in the current period compared to the same period in the prior year.

Marketing Revenues

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. Our marketing revenues increased by $1.6 million to $12.3 million for the year ended December 31, 2025 from $10.7 million for the year ended December 31, 2024. The increase in marketing revenues during the year ended December 31, 2025 was primarily due to a higher pricing environment compared to the year ended December 31, 2024.

Gain on Sale of Business

For the year ended December 31, 2025, we did not sell any businesses or subsidiaries. For the year ended December 31, 2024, we sold our wholly-owned subsidiary, Chaffee, for $104.4 million, net of third-party transaction costs. The assets sold had an approximate carrying value of $97.3 million, which resulted in a gain on the sale of Chaffee of $7.1 million.

Gains (Losses) on Sales of Assets, Net

For the year ended December 31, 2025, we recognized a loss of $1.8 million on sales of assets compared to a gain of $3.5 million on sales of assets during the year ended December 31, 2024. During the year ended December 31, 2025, we wrote-down our Bridgeport office building by $2.4 million to its sale price of $5.5 million. This was offset by other property and equipment sold for $1.3 million in proceeds, which resulted in a gain on sale of these assets of $0.6 million. For the year ended December 31, 2024, we sold other properties for $5.0 million in proceeds, which resulted in a gain on the sale of these properties of $3.5 million.

Section 45Q Tax Credits

Our Section 45Q tax credits relate to CO_2 waste sequestration activities associated with our Barnett Zero Project. Our Section 45Q tax credits decreased by $2.3 million, or 16%, to $11.8 million for the year ended December 31, 2025, from $14.0 million for the year ended December 31, 2024. This decrease was due to lower volumes of CO_2 waste sequestered during the year ended December 31, 2025, reflecting routine fluctuations in activity levels that occur as part of our normal operations.

Related Party Revenues

Our related party revenues were $1.8 million for the year ended December 31, 2025, compared to $3.1 million for the year ended December 31, 2024. The decrease of $1.3 million, or 43%, in related party revenues was due to a decrease in operating fee income with BKV-BPP Power, attributable to lower contracted rates.

Other Revenue

Other revenues, which primarily includes the sale of third party gas, was $11.7 million for the year ended December 31, 2025 compared to $6.6 million for the year ended December 31, 2024. The year-over-year increase was primarily due to an increase in gas prices and contracted rates.

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)	**2025**	**2024**	**$ Change**	**% Change**
Operating expenses				
Lease operating and workover	$ 152,873	$ 136,991	$ 15,882	12 %
Taxes other than income	50,762	35,009	15,753	45 %
Gathering and transportation costs	250,849	222,391	28,458	13 %
Depreciation, depletion, amortization, and accretion	157,464	217,533	(60,069)	(28)%
General and administrative	124,355	104,473	19,882	19 %
Other	54,893	19,385	35,508	*
Total operating expense	$ 791,196	$ 735,782		
Average costs per Mcfe				
Lease operating and workover	$ 0.50	$ 0.47	$ 0.03	6 %
Taxes other than income	0.17	0.12	0.05	42 %
Gathering and transportation costs	0.82	0.77	0.05	6 %
Depreciation, depletion, amortization, and accretion	0.52	0.75	(0.23)	(31)%
General and administrative	0.41	0.36	0.05	14 %
Other	0.18	0.07	0.11	*
Total	$ 2.60	$ 2.54		

**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,					
	2025		2024		$ Change	% Change
(in thousands, other than percentages and average costs)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**		

Lease operating expenses	$ 145,631	$ 0.48	$ 132,317	$ 0.46	$ 13,314	10 %
Workover expenses	7,242	0.02	4,674	0.01	2,568	55 %
Total lease operating and workover expense	$ 152,873	$ 0.50	$ 136,991	$ 0.47	$ 15,882	12 %

Lease operating and workover expenses were $152.9 million, or $0.50 per Mcfe, for the year ended December 31, 2025, an increase of $15.9 million, or 12%, from $137.0 million, or $0.47 per Mcfe, for the year ended December 31, 2024. The increase was primarily attributable to $9.2 million of lease operating and workover expenses associated with BKV Barnett II, which was acquired in connection with the Bedrock Acquisition in September 2025. In addition, lease operating and workover expenses increased due to higher project activity related to our Pad of the Future program of $5.0 million and higher vehicle expenses of $1.0 million during 2025. In addition, during the year ended December 31, 2024, we received a credit of $1.5 million for a water sharing agreement that related to 2023. These increases were partially offset by lower compression and water expenses of $1.5 million and favorable timing of inspection fees of $0.6 million during the year ended December 31, 2025, compared to the year ended December 31, 2024.

Taxes Other Than Income

Taxes other than income were $50.8 million, or $0.17 per Mcfe, for the year ended December 31, 2025, which was an increase of $15.8 million, or 45%, from $35.0 million, or $0.12 per Mcfe, for the year ended December 31, 2024. The increase in taxes other than income during the year ended December 31, 2025, compared to 2024, was due to increases in production taxes of $16.0 million in the Barnett, which includes increases of $1.6 million in production taxes from the BKV Barnett II from the Bedrock Acquisition, and increases of $0.6 million in severance taxes related to our NEPA natural gas properties. BKV Barnett II also incurred $0.5 million of ad valorem taxes during the year ended December 31, 2025. This was offset by decreases in ad valorem and property taxes associated with our operations in the Barnett of $1.4 million. Certain ad valorem and production taxes are not applicable to our NEPA properties.

Gathering and Transportation

Gathering and transportation expenses were $250.8 million, or $0.82 per Mcfe, for the year ended December 31, 2025, which was an increase of $28.5 million, or 13%, from $222.4 million, or $0.77 per Mcfe, for the year ended December 31, 2024. This increase was primarily attributable to higher natural gas and NGL production, which increased gathering and transportation expenses by $21.2 million, including an increase of $6.9 million related to production from BKV Barnett II. In addition, higher gathering and transportation rates for natural gas and NGLs of $8.5 million contributed to the increase in gathering and transportation expenses. This was offset by a $1.3 million decrease in gathering costs associated with our midstream business.

Depreciation, Depletion, Amortization, and Accretion

Depreciation, depletion, amortization, and accretion was $157.5 million, or $0.52 per Mcfe, for the year ended December 31, 2025, which was a decrease of $60.1 million, or 28%, from $217.5 million, or $0.75 per Mcfe, for the year ended December 31, 2024. The decrease in depreciation, depletion, amortization, and accretion during the year ended December 31, 2025, compared to the year ended December 31, 2024, was primarily due to a depletion rate adjustment in 2025, which was driven by higher reserves.

General and Administrative

General and administrative expenses were $124.4 million, or $0.41 per Mcfe, for the year ended December 31, 2025, which was an increase of $19.9 million, or 19%, from $104.5 million, or $0.36 per Mcfe, for the year ended December 31, 2024. The increase in general and administrative expenses during the year ended December 31, 2025, compared to the year ended December 31, 2024, was due to increases from Company-wide growth initiatives of $10.1 million in contract labor, employee-based compensation, and employee expenses, $7.2 million in consulting and information technology-related expenses, and $2.3 million in severance costs.

Other Operating Expenses

Other operating expenses were $54.9 million, or $0.18 per Mcfe, for the year ended December 31, 2025, which was an increase of $35.5 million, from $19.4 million, or $0.07 per Mcfe, for the year ended December 31, 2024. The increase was primarily driven by acquisition and transaction-related costs, including $15.8 million of integration costs associated with the Bedrock Acquisition, $5.5 million of costs and fees related to CCUS transactions, and $1.5 million in transaction costs incurred in connection with the BKV-BPP Power Joint Venture Transaction. In addition, other operating expenses increased due to a $6.0 million increase in gas purchases resulting from higher volumes and natural gas prices, a $5.6 million write-off related to an enterprise resource planning system, a $1.7 million increase in legal matters, and $1.5

million in project write-offs. These increases were partially offset by $2.0 million of waste emissions costs accrued in 2024 under the Inflation Reduction Act that were not accrued in 2025 due to changes in the regulatory environment.

Other Income (Expense)

Gains on contingent consideration liabilities. For the year ended December 31, 2024, 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 $9.7 million for the year ended December 31, 2024, consisting of a gain of $7.5 million and a gain of $2.2 million from the Devon Barnett Acquisition and the Exxon Barnett Acquisition, respectively. The contingent consideration provisions under these purchase agreements expired in 2024.

Earnings (losses) from equity affiliate. Earnings from our equity affiliate was $14.9 million for the year ended December 31, 2025, which was an increase of $4.5 million, from $10.4 million for the year ended December 31, 2024. Earnings from our equity affiliate is related to our investment in, and our proportionate share in the income or losses of the BKV-BPP Power Joint Venture.

Loss on early extinguishment of debt. Loss on early extinguishment of debt was $13.9 million for the year ended December 31, 2024, in connection with the early termination of our Term Loan Credit Agreement and Revolving Credit Agreement that took place in June 2024.

Interest expense. Interest expense was $28.6 million for the year ended December 31, 2025, which was a decrease of $16.9 million, from $45.6 million for the year ended December 31, 2024. The decrease in interest expense during the year ended December 31, 2025, was primarily due to lower interest rates and a lower outstanding balance on our RBL Credit Agreement, which we entered into on June 11, 2024, and subsequently paid down the outstanding balances on our SCB Credit Facility, the Revolving Credit Agreement, and the Term Loan Credit Agreement, which incurred higher interest rates.

Interest expense, related party. Interest expense from our related party borrowings with BNAC was $5.2 million for the year ended December 31, 2024, which was repaid in September 2024. We did not have any related party borrowings during the year ended December 31, 2025.

Interest income. Interest income was $1.6 million for the year ended December 31, 2025, which was a decrease of $2.3 million, from $3.9 million for the year ended December 31, 2024. The decrease was due to the cessation of interest earned on restricted cash following the repayment of the Term Loan Credit Agreement in June 2024, which had previously funded the debt service reserve account.

Income tax benefit (expense). For the year ended December 31, 2025, we had an income tax expense of $35.4 million, which was a change of $79.0 million, from an income tax benefit of $43.6 million for the year ended December 31, 2024. The year-over-year change was primarily due to a pre-tax income for the year ended December 31, 2025 compared to a pre-tax loss for the year ended December 31, 2024.

Results of Operations

Comparison of the Year Ended December 31, 2024 and 2023

Operating Revenues and Operating Income

Our operating revenues and other income from operations include the activity from the sale of natural gas, NGLs, and oil, midstream revenues, gains and losses on our derivative contracts and on the sales of our business and assets, marketing revenues, Section 45Q tax credits, related party revenues, and other income from operations. The following table provides information on our revenues and other operating income for the periods presented:

(in thousands, other than percentages)	Year Ended December 31, 2024	2023	$ Change	% Change
Revenues				
Natural gas revenues	$ 385,456	$ 509,846	$ (124,390)	(24)%
NGL revenues	165,508	187,860	(22,352)	(12)%
Oil revenues	6,606	8,445	(1,839)	(22)%
Midstream revenues	12,560	16,168	(3,608)	(22)%
Derivative gains (losses), net	(34,152)	238,743	(272,895)	*
Marketing revenues	10,668	8,710	1,958	22 %
Gain on sale of business	7,080	—	7,080	*
Gain on sales of assets, net	3,523	2,207	1,316	60 %
Section 45Q tax credits	14,021	701	13,320	*
Related party revenues	3,080	3,593	(513)	(14)%
Other	6,631	3,957	2,674	68 %
Total revenues and other operating income	$ 580,981	$ 980,230		

**Percentage not meaningful*

Natural Gas Revenues

Our natural gas revenues decreased by $124.4 million, or 24%, to $385.5 million for the year ended December 31, 2024, from $509.8 million for the year ended December 31, 2023. The impact of commodity price decreases, excluding the effect of derivative settlements, provided a $81.4 million decrease in year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes). The decrease was also due to lower production volumes during the year ended December 31, 2024, primarily from the assets from the Exxon Barnett Acquisition, and from the sale of Chaffee and certain non-operated assets held by Chelsea, which collectively accounted for a $43.0 million decrease in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price).

NGL Revenues

Our NGL revenues decreased by $22.4 million, or 12%, to $165.5 million for the year ended December 31, 2024, from $187.9 million for the year ended December 31, 2023. The decrease was due to lower production volumes during the year ended December 31, 2024, which accounted for a $12.4 million decrease in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The decrease was also due to the impact of commodity price decreases, excluding the effect of derivative settlements, which accounted for a $10.0 million decrease in year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes).

Oil Revenues

Our oil revenues decreased by $1.8 million, or 22%, to $6.6 million for the year ended December 31, 2024, from $8.4 million for the year ended December 31, 2023. The decrease was due to lower production volumes during the year ended December 31, 2024, which accounted for a $1.6 million decrease in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The decrease was also due to the impact of commodity price decreases, excluding the impact of derivative settlements, which accounted for a $0.2 million decrease in the year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes).

Midstream Revenues

Our midstream revenues decreased by $3.6 million, or 22%, to $12.6 million for the year ended December 31, 2024, from $16.2 million for the year ended December 31, 2023. This decrease was primarily due to the divestiture of Chaffee of $2.6 million as we sold our Repsol Midstream Interest in connection with this sale. The remainder of the decrease was due to the changes in deal structures that reduced midstream transportation revenue while increasing third party gas sales.

Derivative Gains (Losses), Net

For the year ended December 31, 2024, we had net realized and unrealized losses on derivative contracts of $34.2 million compared to net realized and unrealized gains on derivative contracts of $238.7 million for the year ended December 31, 2023. The decreased losses for the year ended December 31, 2024, was primarily attributable to the significant asset positions as of December 31, 2023, reversing due to settlement during 2024, resulting in unrealized losses of $146.7 million, which included the sale of call options in January 2024 limiting our 2026/2027 pricing upside, and is currently in a long term liability position. The year ended December 31, 2023, resulted in unrealized gains of $148.6 million, due to significant liability positions as of December 31, 2022 that reversed and settled during 2023. This was offset by higher realized gains during the year ended December 31, 2024, compared to the year ended December 31, 2023, of $22.3 million, due to slightly lower natural gas prices.

Marketing Revenues

Our marketing revenues increased by $2.0 million to $10.7 million for the year ended December 31, 2024 from $8.7 million for the year ended December 31, 2023. 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 during the year ended December 31, 2024, compared to the year ended December 31, 2023, was primarily due to colder than normal weather in NEPA for the month of January 2024.

Gain on Sale of Business

For the year ended December 31, 2024, we sold our wholly-owned subsidiary, Chaffee, for $104.4 million, net of third party transaction costs. The assets sold had an approximate carrying value of $97.3 million, which resulted in a gain on the sale of Chaffee of $7.1 million.

Gains (Losses) on Sales of Assets, Net

For the year ended December 31, 2024, we sold other properties for $5.0 million in proceeds, which resulted in a gain on the sale of these properties of $3.6 million. For the year ended December 31, 2023, we sold land and our solar assets for $6.7 million in proceeds, which resulted in a gain on sale of assets of $2.2 million.

Section 45Q Tax Credits

Our Section 45Q tax credits increased by $13.3 million to $14.0 million for the year ended December 31, 2024 from $0.7 million for the year ended December 31, 2023. This increase was due to higher volumes of CO_2 waste sequestered in 2024, which started in the fourth quarter of 2023. Our Section 45Q tax credits relate to CO_2 waste sequestration activities associated with our Barnett Zero Project.

Related Party Revenues

We generate a portion of our revenues from a management fee from BKV-BPP Power. Our related party revenues were $3.1 million for the year ended December 31, 2024, compared to $3.6 million for the year ended December 31, 2023. Related party revenues decreased during the year ended December 31, 2024, compared to the year ended December 31, 2023, from the decrease in operating fee income with BKV-BPP Power of $0.5 million due to contracted rate decreases.

Other Revenues

We generate a portion of our revenues from the sale of third-party natural gas. Other revenues was $6.6 million for the year ended December 31, 2024, compared to $4.0 million for the year ended December 31, 2023. The increase year-over-year was primarily due to an increase in third party gas sales of $2.6 million.

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, 2024	2023	$ Change	% Change
Operating expenses				
Lease operating and workover	$ 136,991	$ 150,647	$ (13,656)	(9)%
Taxes other than income	35,009	72,290	(37,281)	(52)%
Gathering and transportation costs	222,391	248,990	(26,599)	(11)%
Depreciation, depletion, amortization, and accretion	217,533	223,370	(5,837)	(3)%
General and administrative	104,473	114,688	(10,215)	(9)%
Other	19,385	12,625	6,760	54 %
Total operating expense	$ 735,782	$ 822,610		
Average costs per Mcfe				
Lease operating and workover	$ 0.47	$ 0.48	$ (0.01)	(2)%
Taxes other than income	0.12	0.23	(0.11)	(48)%
Gathering and transportation costs	0.77	0.79	(0.02)	(3)%
Depreciation, depletion, amortization, and accretion	0.75	0.71	0.04	6 %
General and administrative	0.36	0.37	(0.01)	(3)%
Other	0.07	0.04	0.03	75 %
Total	$ 2.54	$ 2.62		
**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, 2024		2023		$ Change	% Change
(in thousands, other than percentages and average costs)	Amount	Per Mcfe	Amount	Per Mcfe		
Lease operating expenses	$ 132,317	$ 0.46	$ 142,911	$ 0.46	$ (10,594)	(7)%
Workover expenses	4,674	0.01	7,736	0.02	(3,062)	(40)%
Total lease operating and workover expense	$ 136,991	$ 0.47	$ 150,647	$ 0.48	$ (13,656)	(9)%

Lease operating and workover expenses were $137.0 million, or $0.47 per Mcfe, for the year ended December 31, 2024, which was a decrease of $13.7 million, or 9%, from $150.6 million, or $0.48 per Mcfe, for the year ended December 31, 2023. The decrease in lease operating and workover expenses during the year ended December 31, 2024, compared to the same period in 2023, was due to decreases in compression and water expenses of $5.6 million, materials and labor of $3.6 million, and repairs and maintenance of $2.7 million, all of which were due to cost savings initiatives that began during the second half of 2023 and the divestiture of Chaffee and certain non-operating upstream assets in Chelsea. In addition, during the year ended December 31, 2024, we received a credit of $1.5 million for a water sharing agreement that related to 2023.

Taxes Other Than Income

Taxes other than income were $35.0 million, or $0.12 per Mcfe, for the year ended December 31, 2024, which was a decrease of $37.3 million, or 52%, from $72.3 million, or $0.23 per Mcfe, for the year ended December 31, 2023. The decrease in taxes other than income during the year ended December 31, 2024, compared to 2023 was due to decreases in ad valorem and property taxes, and natural gas and NGL production taxes, both associated with our operations in the Barnett of $27.8 million and $9.2 million, respectively. Certain ad valorem and production taxes are not applicable to our NEPA properties.

Gathering and Transportation

Gathering and transportation expenses were $222.4 million, or $0.77 per Mcfe, for the year ended December 31, 2024, which was a decrease of $26.6 million, or 11%, from $249.0 million, or $0.79 per Mcfe, for the year ended December 31, 2023. This decrease was driven by decreased production in the Barnett and natural gas rate decreases of $15.7 million and $12.2 million, respectively. This was offset by new contracts we entered into during 2024 where we started outsourcing gathering costs with our midstream business of $1.3 million.

Depreciation, Depletion, Amortization, and Accretion

Depreciation, depletion, amortization, and accretion was $217.5 million, or $0.75 per Mcfe, for the year ended December 31, 2024, which was a decrease of $5.8 million, or 3%, from $223.4 million, or $0.71 per Mcfe, for the year ended December 31, 2023. The decrease in depreciation, depletion, amortization, and accretion during the year ended December 31, 2024, compared to the year ended December 31, 2023, was due to lower production during the year ended December 31, 2024, compared to the same period in the prior year, offset by lower estimated proved reserves resulting from lower natural gas prices used in the determination of proved reserves and from the divestiture of Chaffee and certain non-operated upstream assets in Chelsea in June 2024.

General and Administrative

General and administrative expenses were $104.5 million, or $0.36 per Mcfe, for the year ended December 31, 2024, which was a decrease of $10.2 million, or 9%, from $114.7 million, or $0.37 per Mcfe, for the year ended December 31, 2023. The decrease was driven by a $22.2 million reduction in equity-based compensation related to the expiration of performance-based restricted stock units (“PRSU”) on December 31, 2023, and an $8.0 million decrease in management fees following the termination of the Verde CO2 contract in November 2023. These cost savings were partially offset by a $12.6 million acceleration of time-based restricted stock units (“TRSU”) recognized upon the IPO (including $2.5 million in payroll taxes), $3.5 million in stock compensation expense under the 2024 Equity and Incentive Compensation Plan (the "2024 Plan"), and $3.7 million in higher payroll costs due to increased headcount in 2024.

Other Operating Expenses

Other operating expenses were $19.4 million, or $0.07 per Mcfe, for the year ended December 31, 2024, which was an increase of $6.8 million, or 54%, from $12.6 million, or $0.04 per Mcfe, for the year ended December 31, 2023. The increase in other operating expenses during the year ended December 31, 2024 was primarily driven by the following factors: $5.3 million in CCUS operating expenses for CO_2 purchases and fuel and increased legal contingencies, $3.4 million in higher emissions monitoring costs, $2.1 million in well clean up costs and expenses related to a potential CCUS equity raise and investments, and $1.0 million in costs from the newly enacted EPA fees under the Inflation Reduction Act. These increases were offset by $3.6 million of inventory restocking and rig termination fees, $2.0 million of prior year inventory restocking fees and write-offs, and $0.7 million of lower midstream operating expenses and gas purchases.

Other Income (Expense)

Gains 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 $9.7 million in 2024, compared to $38.4 million in 2023, which was a decrease of $28.7 million. The decrease was primarily attributable to lower gains on contingent consideration liabilities with the Devon Barnett Acquisition and the Exxon Barnett Acquisition. Gains related to the Devon Barnett Acquisition were $7.5 million in 2024 compared to $25.0 million in 2023, and gains related to the Exxon Barnett Acquisition were $2.2 million in 2024 compared to $13.4 million in 2023. The higher gains in 2023 were due to a significant decrease in the forward curve commodity pricing for natural gas (NYMEX) and oil (WTI) assumptions used in the Monte Carlo simulations during that year compared to slight decreases in 2024.

Earnings from equity affiliate. Earnings from our equity affiliate was $10.4 million for the year ended December 31, 2024, which was a decrease of $6.4 million, from $16.9 million compared to the year ended December 31, 2023. Earnings from our equity affiliate is related to our investment in, and our proportionate share in the income or losses of, the BKV-BPP Power Joint Venture.

Loss on early extinguishment of debt. Loss on early extinguishment of debt was $13.9 million for the year ended December 31, 2024, in connection with the early termination of our Term Loan Credit Agreement and Revolving Credit Agreement that took place in June 2024.

Interest expense. Interest expense was $45.6 million for the year ended December 31, 2024, which was a decrease of $24.4 million from $69.9 million for the year ended December 31, 2023. The decrease in interest expense during the year ended December 31, 2024, was primarily due to lower interest rates on our RBL Credit Agreement, which we entered into on June 11, 2024, and the subsequent paydown on the outstanding balances on our SCB Credit Facility, the Revolving Credit Agreement, and the Term Loan Credit Agreement, which incurred higher interest rates.

Interest expense, related party. Interest expense from our related party was $5.2 million for the year ended December 31, 2024, which was a decrease of $1.9 million from $7.1 million for the year ended December 31, 2023. The decrease was primarily due to the payment in full of the loan with BNAC in 2023, which provided nine months of interest compared to none in 2024. This was slightly offset by an increase in the interest on the loan under the related party loan with BNAC, which provided for seven months of interest in 2023 compared to a full year in 2024.

Income tax benefit (expense). For the year ended December 31, 2024, we had an income tax benefit of $43.6 million, which was a change of $71.8 million, from an income tax expense of $28.2 million for the year ended December 31, 2023. The year-over-year change was primarily due to a pre-tax loss for the year ended December 31, 2024, compared to a pre-tax income for the year ended December 31, 2023. During the year ended December 31, 2024, we also recognized additional income tax expense due to executive compensation disallowance, which was offset by a tax benefit from the monetization of Section 45Q tax credits associated with the injection of CO_2 waste in the Barnett Zero Project, Code Section 45I Marginal Well Credits from marginal production, excess tax benefits relating to the vesting of restricted shares, and by state apportionment changes due to the sale of Chaffee.

Liquidity and Capital Resources

Capital Commitments

Our primary needs for cash are to fund our upstream development, midstream, power, and CCUS activities, fund operations and capital expenditures, acquisitions and asset retirement obligations, cover any debt interest or minimum volume commitment obligations, pay down debt, and return capital to stockholders. Our primary uses of cash during the year ended December 31, 2025 were to fund the Bedrock Acquisition and the development of our natural gas properties. Our primary uses of cash during the years ended December 31, 2024 and 2023 were to pay down debt and fund the development of our natural gas properties.

During the years ended December 31, 2025, 2024, and 2023, cash paid for capital expenditures was $300.2 million, $100.9 million, and $187.7 million, respectively. Our current estimated budget for total accrued capital expenditures in 2026 is approximately $410 million to $560 million on a Company-wide basis. To help fund these capital expenditures, we expect to receive approximately $50 million to $70 million of capital contributions from our joint venture partners in our CCUS and power businesses. Expected contributions from our joint venture partners would bring our net 2026 capital expenditure range to $360 million to $490 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.

On January 14, 2026, we entered into a manufacturing reservation agreement related to a planned power generation project. Under the agreement, we are committed to pay up to an aggregate of $80.0 million in reservation fees, scheduled in phases during 2026, to secure future manufacturing capacity through 2028 for turbines with up to approximately 1,230 megawatts in total generation capacity. Amounts paid are generally non-refundable and will be credited against the purchase price if a definitive supply agreement is executed.

Capital Resources

Historically, our primary sources of capital and liquidity have consisted of internally generated cash flows from operations, together with loans and capital contributions from our majority stockholder, BNAC. We also enter into financial instruments to reduce the impact of commodity price volatility and provide a level of certainty and stability around cash flows. We currently believe that our cash flows from operations, cash on hand, borrowings under our RBL Credit Agreement and the 2030 Senior Notes, the 2025 Equity Offering, and our commodity hedges in place will provide sufficient liquidity to fund our operations and our capital expenditures into 2026, excluding our CCUS business. We expect to fund the majority of our CCUS business from a variety of external sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations.

The following table summarizes our cash flows for the years ended December 31, 2025, 2024, and 2023 (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Net cash provided by operating activities	$ 242,707	$ 118,538	$ 123,076
Net cash provided by (used in) investing activities	(564,903)	36,066	(177,848)
Net cash provided by (used in) financing activities	506,740	(304,805)	66,713
Net increase (decrease) in cash, cash equivalents, and restricted cash	$ 184,544	$ (150,201)	$ 11,941

Cash flows provided by operating activities. Net cash provided by operating activities was $242.7 million for the year ended December 31, 2025, compared to $118.5 million for the year ended December 31, 2024. The increase of $124.2 million was due to a $69.1 million increase in income from operations (excluding non-cash items), resulting from higher natural gas volumes and prices compared to 2024, a favorable $45.3 million change in working capital, and a $44.1 million decrease in cash paid for interest. These increases were offset by $23.5 million of cash received in January 2024 for the sale of call options and $16.2 million of cash paid in February 2025 for the purchase of put options.

Net cash provided by operating activities was $118.5 million for the year ended December 31, 2024, compared to $123.1 million for the year ended December 31, 2023. The decrease of $4.5 million was due to a $41.5 million decrease in income from operations (excluding non-cash items), resulting from lower natural gas prices compared to 2023, an unfavorable $17.3 million change in working capital, $10.0 million in distributions from the BKV-BPP Power Joint Venture made in 2023, and $3.9 million of transaction costs associated with the sale of Chaffee and certain non-operated upstream assets in Chelsea. These decreases were offset by reduced settlements of contingent liabilities of $45.0 million and cash received from the sale of call options of $23.5 million.

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 provided by (used in) investing activities. Net cash used in investing activities was $564.9 million for the year ended December 31, 2025, compared to net cash provided by investing activities of $36.1 million for the year ended December 31, 2024. The increase in cash outflows of $601.0 million was due to the $272.1 million of cash paid for the Bedrock Acquisition, a $172.1 million increase in capital expenditures (excluding CCUS activities), and a $27.1 million increase in CCUS expenditures for the year ended December 31, 2025 compared to the prior year. These outflows were offset by $2.1 million of cash acquired in consolidation of BKV-BPP Cotton Cove and a $1.8 million increase in proceeds from sales of assets for the year ended December 31, 2025 compared to the prior year.

Net cash provided by investing activities was $36.1 million for the year ended December 31, 2024, compared to net cash used in investing activities of $177.8 million for the year ended December 31, 2023. The increase in cash inflows of $213.9 million was due to the $132.6 million of total proceeds from the sale of Chaffee and certain non-operated upstream assets held by Chelsea during the year ended December 31, 2024. The change was also due to a decrease of $49.0 million in capital expenditures (excluding CCUS activities), a $37.8 million reduction of CCUS-related expenditures, and a $4.9 million decrease in cash used for acquisition of natural gas properties for the year ended December 31, 2024 compared to the prior year. These inflows were offset by a reduction of $10.4 million of cash proceeds from other investing activities for the year ended December 31, 2024 compared to the prior year.

The following table presents our capital expenditures (excluding leasehold costs and acquisitions) on an accrual basis for the years ended December 31, 2025, 2024, and 2023 and reconciles to cash flows used for capital expenditures in the consolidated statements of cash flows.

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Total use of cash and cash equivalents for capital expenditures	$ (300,165)	$ (100,916)	$ (187,716)
(Increase) decrease in accrued capital expenditures	(18,344)	(16,710)	23,863
Capital expenditures (accrued)	$ (318,509)	$ (117,626)	$ (163,853)

Cash flows provided by (used in) financing activities. Net cash provided by financing activities was $506.7 million for the year ended December 31, 2025, primarily driven by $500.0 million of proceeds from the issuance of the 2030 Senior Notes and $170.6 million of net proceeds from the 2025 Equity Offering (after deducting underwriting discounts and commissions). Financing inflows also included $19.8 million of cash contributions from noncontrolling interest. These inflows were partially offset by $165.0 million of net debt repayments, $15.9 million in payments of debt issuance costs, $1.6 million of net shares withheld for income taxes upon vesting of restricted stock units, and $1.2 million of cash distributions to noncontrolling interest.

Net cash used in financing activities was $304.8 million for the year ended December 31, 2024, which consisted of $493.0 million of net payments on debt, $53.2 million of payments for taxes related to net share settlement of restricted stock units, and $18.3 million for payments of debt issuance costs and debt extinguishment costs. These outflows were partially offset by $265.7 million of net proceeds from the issuance of common stock from our IPO (after deducting underwriting discounts and commissions).

Net cash provided by financing activities was $66.7 million for the year ended December 31, 2023, which consisted of $258.5 million and $117.0 million of advances received from the Revolving Credit Facilities and Revolving Credit Agreement, respectively. In addition, we received $150.0 million of capital contributions from BNAC in exchange for 7,500,000 shares of our common stock. These inflows were offset by $114.0 million, $272.5 million and $66.0 million of repayments made on our Term Loan Credit Agreement, Revolving Credit Facilities and Revolving Credit Agreement, respectively.

Working Capital

As of December 31, 2025, we had cash and cash equivalents of $199.4 million, compared to $14.9 million of cash and cash equivalents as of December 31, 2024. Our net working capital surplus was $170.0 million as of December 31, 2025, compared to a working capital deficit of $71.6 million as of December 31, 2024.

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. Furthermore, we expect that our pace of development, production volumes, commodity prices, and differentials to NYMEX pricing for our natural gas and oil production will be the largest variables impacting our working capital.

2030 Senior Notes

On September 26, 2025, BKV Upstream Midstream issued in a private placement $500.0 million of the 2030 Senior Notes. The 2030 Senior Notes were issued at par and resulted in proceeds of $490.0 million, after deducting underwriters' discounts and commissions. The proceeds were used to repay a portion of the outstanding borrowings under the RBL Credit Agreement and fund a portion of the cash consideration for the Bedrock Acquisition, with the remainder of the purchase price being funded with shares of our common stock. In connection with the issuance of the 2030 Senior Notes, we recorded debt issuance costs of $13.6 million, which are amortized to interest expense on the consolidated statements of operations over the term of the 2030 Senior Notes.

Interest on the 2030 Senior Notes is payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2026. The 2030 Senior Notes are guaranteed on a senior unsecured basis by us and all of BKV Upstream Midstream's existing restricted subsidiaries and certain future subsidiaries (collectively, the "BKV Guarantors," and such guarantees, the "Guarantees"). These Guarantees are full, unconditional, joint, and several among the BKV Guarantors, subject to certain customary release provisions. The indenture governing the 2030 Senior Notes contains customary events of default, as well as cross-default provisions with other indebtedness of BKV Upstream Midstream and its restricted subsidiaries.

On or after October 15, 2027, BKV Upstream Midstream may, on any one or more occasions, redeem some or all of its 2030 Senior Notes prior to their maturity at redemption prices plus accrued and unpaid interest as described in the indenture governing the 2030 Senior Notes. BKV Upstream Midstream may redeem up to 40% of the aggregate principal amount of the 2030 Senior Notes before October 15, 2027, with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price described in the indenture governing the 2030 Senior Notes plus accrued and unpaid interest to, but excluding, the redemption date. In addition, prior to October 15, 2027, BKV Upstream Midstream may redeem some or all of the 2030 Senior Notes at a price equal to 100% of the principal amount thereof, plus a make-whole premium as described in the indenture governing the 2030 Senior Notes, plus accrued and unpaid interest.

Loan Agreements and Credit Facilities

RBL Credit Agreement

On June 11, 2024, BKV Corporation, as a guarantor, and BKV Upstream Midstream, as borrower, entered into the RBL Credit Agreement with Citibank, N.A., as the administrative agent, and the financial institutions party thereto. The RBL Credit Agreement includes a maximum credit commitment of $1.5 billion. On September 22, 2025, with the unanimous consent of the RBL Credit Agreement's lenders, we amended the RBL Credit Agreement to, among other things, increase the borrowing base by $150.0 million and the elected commitment by $135.0 million upon closing of the Bedrock Acquisition (among other conditions). This amendment constituted a semiannual borrowing base redetermination. As of December 31, 2025, the RBL Credit Agreement had a borrowing base of $1.0 billion, an elected commitment of $800.0 million, and the ability to issue up to $40.0 million in letters of credit.

The loans under the RBL Credit Agreement may be borrowed, repaid, and reborrowed during the term of the RBL Credit Agreement. The RBL Credit Agreement will mature on June 12, 2028. The obligations under the RBL Credit Agreement are secured and guaranteed on a senior secured basis by BKV Upstream Midstream and all of BKV Upstream Midstream’s current and future material restricted subsidiaries. Loans under the RBL Credit Agreement bear interest at one, three, or six-month term SOFR or ABR, as applicable, plus a credit spread adjustment of 0.10% for SOFR borrowings, plus an applicable margin 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 RBL Credit Agreement, including commitment fees on the average daily amount of the undrawn portion of the commitments. As of March 6, 2026, $110.0 million of revolving borrowings and $15.0 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $675.0 million of available capacity thereunder for future borrowings and letters of credit.

The RBL Credit Agreement contains various restrictive covenants that, among other things, limit BKV Upstream Midstream's ability and the ability of its restricted subsidiaries to, subject to certain exceptions: (i) incur indebtedness; (ii) incur liens; (iii) acquire or merge with any other company; (iv) sell assets or equity interests of their subsidiaries; (v) make investments; (vi) pay dividends or make other restricted payments; (vii) change their lines of business; (viii) enter into certain hedge agreements; (ix) enter into transactions with affiliates; (x) own any subsidiary that is not organized in the United States; (xi) prepay any unsecured senior or subordinated indebtedness; (xii) engage in certain marketing activities; and (xiii) allow, on a net basis, gas imbalances, take-or-pay or other prepayments with respect to their proved oil and gas properties.

The RBL Credit Agreement requires BKV Upstream Midstream and its restricted subsidiaries to always hedge not less than 50% of reasonably anticipated projected production from their proved developed producing reserves for the subsequent 24 calendar month period immediately following the date financial statements are required to be delivered under the RBL Credit Agreement for each fiscal quarter.

The RBL Credit Agreement also includes financial covenants that require BKV Upstream Midstream to maintain:

- on a quarterly basis, a minimum Current Ratio (as defined in the RBL Credit Agreement) of no less than 1.00 to 1.00; and
- on a quarterly basis, a Net Leverage Ratio (as defined in the RBL Credit Agreement) of no greater than 3.25 to 1.00.

The RBL Credit Agreement includes customary equity cure rights that will enable us to cure certain breaches of the minimum current ratio covenant or the maximum net leverage ratio covenant (subject to certain limitations in the RBL Credit Agreement).

The RBL Credit Agreement generally includes customary events of default for a reserve-based credit facility, some of which allow for an opportunity to cure. 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. The RBL Credit Agreement is secured by substantially all of BKV Upstream Midstream's assets and those of the guarantors, and upon an event of default the agent under the RBL Credit Agreement could commence foreclosure proceedings.

Revolving Credit Agreements and Term Loan Credit Agreement

On June 11, 2024, using the funds from the RBL Credit Agreement, we repaid the outstanding debt balances under (i) the Term Loan Credit Agreement, (ii) the Revolving Credit Agreement, and (iii) our loan agreement previously entered into in March 2022 with Standard Charter Bank (the "SCB Credit Facility"), in each case with proceeds from the loans under the RBL Credit Agreement and cash on hand. The Term Loan Credit Agreement, the Revolving Credit Agreement, and the SCB Credit Facility were terminated concurrently with the repayment of the remaining amounts owed thereunder.

BKV-BPP Power and BKV-BPP Cotton Cove Joint Ventures

Under the terms of the BKV-BPP Power LLC Agreement and BKV-BPP Cotton Cove LLC Agreement, as applicable, we do not have the ability to unilaterally cause BKV-BPP Power or BKV-BPP Cotton Cove to make distributions. During the years ended December 31, 2025 and 2024, no distributions were made by BKV-BPP Power or BKV-BPP Cotton Cove. During the year ended December 31, 2023, BKV-BPP Power made a distribution of $10.0 million to BKV Corporation. In addition, we may be required to make additional capital contributions to one or both joint ventures to fund items approved in their respective annual budgets or other matters approved by their respective boards. Such additional capital contributions, which are not subject to any limit on the potential amount required, would reduce the amount of cash otherwise available to us. However, following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, any additional capital contributions to BKV-BPP Power must be approved by a majority of BKV-BPP Power's twelve member board of managers, nine of whom are appointed by us and three of whom are appointed by BPPUS. Similarly, any additional capital contributions to BKV-BPP Cotton Cove must receive the unanimous approval of the BKV-BPP Cotton Cove Joint Venture's six-member board of managers, four of whom are appointed by us and two of whom are appointed by BPPUS.

On June 26, 2025, BKV dCarbon Ventures and BPPUS amended and restated the BKV-BPP Cotton Cove LLC Agreement whereby on July 9, 2025, BKV dCarbon Ventures contributed $3.3 million to BKV-BPP Cotton Cove, net of $0.1 million of expenditures paid by BKV dCarbon Ventures on behalf of BKV-BPP Cotton Cove, and on July 10, 2025, BPPUS received $5.4 million of its initial capital contribution of $8.6 million from BKV-BPP Cotton Cove. Subsequent to these transactions, BKV dCarbon Ventures contributed an additional $5.8 million, for a total of $9.0 million, and BPPUS contributed an additional $5.5 million, for a total of $8.8 million, for the year ended December 31, 2025.

On October 29, 2025, we entered into a Membership Interest Purchase Agreement with BPPUS to acquire one-half of the limited liability company interests of the BKV-BPP Power Joint Venture then held by BPPUS upon the terms and subject to the conditions of the purchase agreement. On January 30, 2026, we completed the BKV-BPP Power Joint Venture Transaction for aggregate consideration consisting of $115.1 million in cash and 5,315,390 shares of our common stock.

We funded the cash consideration with a combination of cash on hand and the net proceeds from the 2025 Equity Offering. For additional information, see *Note 14 - Investments* and *Note 19 - Subsequent Events*.

For more information about our joint ventures with BPPUS, see "*—Risk Factors — Risks Related to Our Power Generation Business — We operate our power generation business through a joint venture that requires the consent of BPPUS for certain material actions.*" and "*Risk Factors — Risks Related to Our CCUS Business — We operate the Cotton Cove Project through a joint venture that requires the consent of BPPUS for certain material actions.*"

Internal Controls and Procedures

As an accelerated filer, we are required to comply with the SEC's rules implementing Section 404(a) of the Sarbanes-Oxley Act of 2022. Accordingly, management is required to assess, and report on the effectiveness of our internal control over financial reporting as of the end of each fiscal year, beginning with this Annual Report on Form 10-K. In addition, we are required to disclose any change in our internal control over financial reporting that occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 December 31, 2025, our material off-balance sheet arrangements and transactions included natural gas transportation commitments of $259.4 million and letters of credit of $15.0 million against the RBL Credit Agreement. For further information regarding these arrangements, see *Note 16 - Commitments and Contingencies* to our consolidated financial statements and under *"—Liquidity and Capital Resources — Loan Agreements and 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. For more information, see Item 8 of Part II, *Financial Statements and Supplementary Data, Note 2 - Summary of Significant Accounting Policies.*

Accounting for Natural Gas and NGL Reserves 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 reserves. 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 reserves 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 reserves estimates are representative of our actual reserves — for example, by involving independent reserves 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.

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.

Accounting for Variable Interest Entities

As described in *Note 14 - Investments* in our consolidated financial statements, on May 8, 2025, BKV dCarbon Ventures, together with C Squared Solutions, Inc., a subsidiary of the Energy Transition Fund managed by Copenhagen Infrastructure Partners (CIP), and for the limited purposes specified therein, BKV Corporation, entered into the BKV-CIP JV Agreement forming the BKV-CIP Joint Venture. On June 26, 2025, BKV dCarbon Ventures and BPPUS amended and restated the BKV-BPP Cotton Cove LLC Agreement whereby on July 9, 2025, BKV dCarbon Ventures contributed $3.3 million to BKV-BPP Cotton Cove, net of $0.1 million of expenditures paid by BKV dCarbon Ventures on behalf of BKV-BPP Cotton Cove, and on July 10, 2025, BPPUS received $5.4 million of its initial capital contribution of $8.6 million from BKV-BPP Cotton Cove. On July 31, 2025, BKV dCarbon Ventures and BPPUS contributed an additional $3.8 million and $3.6 million, respectively. BKV dCarbon Ventures owns a 51% interest and BPPUS owns a 49% interest in BKV-BPP Cotton Cove.

We consider the BKV-CIP Joint Venture and BKV-BPP Cotton Cove Joint Venture to each be a variable interest entity ("VIE") of BKV in accordance with ASC 810, *Consolidation*, as BKV is deemed to be the primary beneficiary of these joint ventures. Generally, a VIE is an entity with at least one of the following conditions: (i) the total equity investment at risk is insufficient to allow the entity to finance its activities without additional subordinated financial support, or (ii) the holders of the equity investment at risk, as a group, lack the characteristics of having a controlling financial interest. The primary beneficiary of a VIE is an entity that has a variable interest or a combination of variable interests that provide such entity with a controlling financial interest in the VIE. An entity is deemed to have a controlling financial interest in a VIE if it has both of the following characteristics: (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and (ii) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

In exchange for cash contributions received from the Class B Member to the BKV-CIP Joint Venture, the BKV-CIP Joint Venture has issued 1,791,155 Class B Units (the "Class B Units") at $10.00 per unit as of December 31, 2025. We determined that the Class B Units should be classified as noncontrolling interest within mezzanine equity on the Company's consolidated balance sheets. The Class B Units are not mandatorily redeemable or currently redeemable, but become exercisable with the passage of time, which is on the second anniversary of the BKV-CIP JV Agreement, or May 8, 2027. Prior to the second anniversary, we determined that there is an embedded put option in the Class B Units, which does not meet the derivative accounting criteria, and is not within the control of the Company. Therefore, the shares of the Class B Units have been classified as noncontrolling interest within mezzanine equity on our consolidated balance sheets. The Class B Units also have a multiple on invested capital equal to 1.65, which may be redeemed on the second anniversary date. The contributions from the Class B Member are accreted to the redemption value over a two-year period (using the effective interest method) with the accretion accounted for as a dividend paid to the Class B Member.

Recent Accounting Pronouncements

See *Note 2 - Summary of Significant Accounting Policies* to our consolidated financial statements included in this Annual Report on Form 10-K 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.

Emerging Growth Company Status

We are an "emerging growth company" as defined in Section 2(a)(19) of 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. We have elected to take advantage of certain of the reduced disclosure obligations in this Annual Report on Form 10-K and may elect to take advantage of other reduced reporting requirements in our future filings with the SEC. As a result, the information that we provide to our stockholders may be different from other public reporting companies.

Under the JOBS Act, emerging growth companies can delay adopting new or revised accounting standards issued subsequent to the enactment of the JOBS Act, until such time as those standards apply to private companies. However, we have irrevocably elected not to avail ourselves of this exemption. Rather, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

We may take advantage of these provisions until the last day of our fiscal year following the fifth anniversary of the date of our IPO. Such fifth anniversary will occur in 2029. However, if certain events occur prior to the end of such five-year period, including if (i) we become a “large accelerated filer,” which requires that the market value of our common equity held by non-affiliates be at least $700 million as of the end of the most recently completed second fiscal quarter, (ii) our gross revenues for any fiscal year equal or exceed $1.235 billion, or (iii) we issue more than $1.0 billion of non-convertible debt in any three-year period, then we will cease to be an emerging growth company prior to the end of such five-year period. We expect to lose our emerging growth company status as of December 31, 2026.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk and Hedging Activities

As of December 31, 2025, we did not enter into any trading market risk sensitive instruments, and our market risk sensitive instruments consisted entirely of non-trading instruments entered into for risk management purposes related to our natural gas and NGL production and power operations. 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 NGL production when management believes that favorable future prices can be secured.

Our financial hedging activities are intended to support natural gas and NGL prices at targeted levels and to manage our exposure to natural gas and NGL 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, 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, 2025 consisted of commodity swaps, basis swaps, put and call options, and producer collar agreements, subject to master netting agreements with each individual counter party.

These derivative contracts cover portions of our projected positions through 2028. Our commodity hedge position as of December 31, 2025 is summarized in *Note 7 - Derivative Instruments* to our consolidated financial statements.

We may enter into single hedge transactions with settlements up to 48 months. The aggregation of these executed hedge instruments may not exceed certain limits without board of director approval of our forecasted production volumes. For the year ended December 31, 2025, a hypothetical increase of $0.10 per Mcf in NYMEX would have resulted in a $13.1 million decrease in natural gas hedge revenues, while a hypothetical decrease of $0.10 per Mcf in NYMEX would have resulted in a $13.2 million increase in natural gas hedge revenues. A hypothetical increase of $1.00 per Bbl of NGL purity product price would have resulted in a $5.6 million decrease, while a $1.00 per Bbl decrease would have resulted in a $5.6 million increase.

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. These HRCOs are entered into to economically hedge power price and fuel cost exposures rather than for trading purposes. 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 BKV-BPP Power, and thus on our business, financial condition, results of operations, and cash flows. 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 BKV-BPP Power, and thus on our business, financial condition, results of operations, and cash flows.

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. Although these derivatives are not designated as accounting hedges for GAAP purposes, they are not entered into for trading or speculative purposes and are intended to manage commodity price and basis risk associated with our 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, 2025, the estimated fair value of our commodity derivative instruments was a net asset of $82.4 million, comprised of current and noncurrent assets and noncurrent liabilities. As of December 31, 2024, the estimated fair value of our commodity derivative instruments was a net liability of $67.6 million, comprised of current and noncurrent liabilities.

By removing price volatility from a portion of our expected production through December 2028, 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 creditworthiness 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.

Interest Rate Risks

As of December 31, 2025, we did not have primary exposure to interest rate risk due to the zero balance on our RBL Credit Agreement. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 2030 Senior Notes, but can affect their fair values. For more information on our 2030 Senior Notes, see *Note 4 - Debt* and *Note 6 - Fair Value Measurements* to our consolidated financial statements included in Item 8 of Part II of this report. The average annualized interest rate incurred on our outstanding variable rate borrowings during the year ended December 31, 2025 was approximately 7.4%. We estimate that a 1.0% increase in the applicable average interest rates during the year ended December 31, 2025 would have resulted in an increase of $1.8 million in interest expense.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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, 2025 and 2024, and the related consolidated statements of operations, of equity and mezzanine equity and of cash flows for each of the three years in the period ended December 31, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 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 audits 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
March 6, 2026
We have served as the Company's auditor since 2020.

BKV CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)

Table of Contents

	December 31,	
	2025	2024
Assets		
Current assets		
Cash and cash equivalents	$ 199,412	$ 14,8
Accounts receivable, net	100,459	50,4
Accounts receivable, related parties	11,559	15,3
Prepaid expenses	6,419	7,6
Inventory	6,072	6,2
Commodity derivative assets, current	61,782	—
Other current assets	2,176	—
Total current assets	387,879	94,6
Natural gas properties and equipment		
Developed properties	2,965,638	2,315,1
Undeveloped properties	13,182	10,7
Midstream assets	277,974	276,6
Accumulated depreciation, depletion, and amortization	(849,464)	(714,2
Total natural gas properties, net	2,407,330	1,888,2
Other property and equipment, net	137,739	97,3
Goodwill	18,417	18,4
Investment in BKV-BPP Power	130,068	115,1
Commodity derivative assets	26,432	—
Other noncurrent assets	21,842	17,3
Total assets	$ 3,129,707	$ 2,231,0
Liabilities, mezzanine equity, and equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 206,934	$ 121,3
Contingent consideration payable	—	20,0
Commodity derivative liabilities, current	—	20,2
Income taxes payable to related party	810	1,4
Other current liabilities	10,147	3,1
Total current liabilities	217,891	166,2
Asset retirement obligations	230,372	198,7
Commodity derivative liabilities	5,767	47,3
Deferred tax liability, net	123,355	88,6
Long-term debt, net	486,777	165,0
Other noncurrent liabilities	5,223	5,4
Total liabilities	1,069,385	671,5
Commitments and contingencies (Note 16)		
Mezzanine equity		
Noncontrolling interest	12,951	—
Stockholders' equity		
Common stock, $0.01 par value; 500,000 authorized shares; 96,872 and 84,600 shares issued and outstanding as of December 31, 2025 and 2024, respectively	1,635	1,5
Treasury stock, shares at cost; 214 shares as of December 31, 2025 and 2024	(6,663)	(6,6
Additional paid-in capital	1,754,930	1,447,6
Retained earnings	288,764	117,0
Total stockholders' equity	2,038,666	1,559,5
Noncontrolling interest	8,705	—
Total equity	2,047,371	1,559,5
Total liabilities, mezzanine equity, and equity	$ 3,129,707	$ 2,231,0

BKV CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

Table of Contents

	For the Year Ended December 31,		
	2025	2024	2023
Revenues and other operating income			
Natural gas, NGL, and oil sales	$ 857,597	$ 557,570	$ 706,151
Midstream revenues	10,456	12,560	16,168
Derivative gains (losses), net	105,081	(34,152)	238,743
Marketing revenues	12,304	10,668	8,710
Gain on sale of business	—	7,080	—
Gains (losses) on sales of assets, net	(1,805)	3,523	2,207
Related party revenues	1,760	3,080	3,593
Section 45Q tax credits	11,752	14,021	701
Other	11,664	6,631	3,957
Total revenues and other operating income	1,008,809	580,981	980,230
Operating expenses			
Lease operating and workover	152,873	136,991	150,647
Taxes other than income	50,762	35,009	72,290
Gathering and transportation	250,849	222,391	248,990
Depreciation, depletion, amortization, and accretion	157,464	217,533	223,370
General and administrative	124,355	104,473	114,688
Other	54,893	19,385	12,625
Total operating expenses	791,196	735,782	822,610
Income (loss) from operations	217,613	(154,801)	157,620
Other income (expense)			
Gains on contingent consideration liabilities	—	9,676	38,375
Earnings from equity affiliate	14,895	10,423	16,865
Loss on early extinguishment of debt	—	(13,877)	—
Interest expense	(28,646)	(45,582)	(69,942)
Interest expense, related party	—	(5,181)	(7,078)
Interest income	1,576	3,859	3,138
Other income	4,837	9,008	6,165
Income (loss) before income taxes	210,275	(186,475)	145,143
Income tax benefit (expense)	(35,431)	43,605	(28,225)
Net income (loss)	174,844	(142,870)	116,918
Less: net income attributable to noncontrolling interest	1,712	—	—
Net income (loss) attributable to BKV	173,132	(142,870)	116,918
Net income (loss) per common share attributable to BKV:			
Basic	$ 1.98	$ (2.00)	$ 1.93
Diluted	$ 1.98	$ (2.00)	$ 1.82
Weighted average number of common shares outstanding:			
Basic	86,581	71,288	60,730
Diluted	86,823	71,288	64,380

The accompanying notes are an integral part of these consolidated financial statements.

BKV CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

Table of Contents

	Year Ended December 31,		
	2025	2024	2023
Cash flows from operating activities:			
Net income (loss)	$ 174,844	$ (142,870)	$ 116,9
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization, and accretion	158,952	217,892	224,4
Equity-based compensation expense	12,845	16,316	25,7
Deferred income tax (benefit) expense	36,435	(44,811)	32,3
Unrealized (gains) losses on derivatives, net	(113,164)	146,679	(148,5
Gains on contingent consideration liabilities	—	(9,676)	(38,3
Settlement of contingent consideration	(20,000)	(20,000)	(65,0
Proceeds from the sale of call options	—	23,502	
Payments for the purchase of put options	(16,206)	—	
Write-off of capitalized software costs	5,643	—	
Gain on sale of business	—	(7,080)	
(Gains) losses on sale of assets, net	1,805	(3,523)	(2,2
Transaction costs from sale of business	—	(3,461)	
Earnings from equity affiliate	(14,895)	(10,423)	(16,8
Distribution from equity affiliate	—	—	10,0
Loss on early extinguishment of debt	—	13,877	
Other, net	3,692	(3,874)	3,0
Changes in operating assets and liabilities:			
Accounts receivable, net	(35,462)	(4,652)	86,4
Accounts receivable, related party	3,812	(14,812)	(1
Accounts payable and accrued liabilities	46,720	(32,165)	(98,2
Other changes in operating assets and liabilities	(2,314)	(2,381)	(6,5
Net cash provided by operating activities	242,707	118,538	123,0
Cash flows from investing activities:			
Asset acquisition	(272,096)	—	(4,8
Cash acquired in consolidation of BKV-BPP Cotton Cove	2,077	—	
Capital expenditures	(300,165)	(100,916)	(187,7
Proceeds from sale of business	—	132,571	
Proceeds from sales of assets	6,876	5,060	6,6
Loan advanced to equity affiliate	—	—	(8,0
Loan repayment from equity affiliate	—	—	8,0
Other investing activities, net	(1,595)	(649)	8,0
Net cash provided by (used in) investing activities	(564,903)	36,066	(177,8
Cash flows from financing activities:			
Proceeds from issuance of common stock in initial public offering, net of underwriting discounts and commissions	—	265,661	
Proceeds from the issuance of common stock, net of underwriting discounts and commissions	170,635	—	150,0
Proceeds on long-term debt	500,000	—	
Proceeds from notes payable from related party	—	—	17,0
Payments on notes payable to related party	—	(75,000)	(17,0
Proceeds under RBL Credit Agreement	577,000	580,000	
Payments on RBL Credit Agreement	(742,000)	(415,000)	
Payment on term loan agreement	—	(456,000)	(114,0
Payment of debt issuance costs	(15,869)	(8,054)	
Proceeds from draws on credit facilities	—	44,000	375,5
Payments on credit facilities	—	(171,000)	(338,5
Payments of deferred offering costs	—	(3,879)	(2,9
Debt extinguishment costs	—	(10,213)	
Cash distributions to noncontrolling interest	(1,225)	—	
Cash contributions from noncontrolling interest	19,818	—	
Net share settlements, equity-based compensation	(1,619)	(53,239)	(2,9

Other financing activities	—	(2,081)	(4
Net cash provided by (used in) financing activities	506,740	(304,805)	66,7
Net increase (decrease) in cash, cash equivalents, and restricted cash	184,544	(150,201)	11,9
Cash, cash equivalents, and restricted cash, beginning of period	14,868	165,069	153,1
Cash, cash equivalents, and restricted cash, end of period	$ 199,412	$ 14,868	$ 165,0

The accompanying notes are an integral part of these consolidated financial statements.

BKV CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

Table of Contents

	Year Ended December 31,		
Supplemental cash flow information:	**2025**	**2024**	**2023**
Cash payments for:			
Interest	$ 16,441	$ 60,492	$ 68,480
Income tax	$ 232	$ 6	$ 1,545
Non-cash investing and financing activities:			
Equity issued as consideration for acquisition	$ 124,254	$ —	$ —
Conversion of mezzanine equity to common stock upon initial public offering	$ —	$ 42,995	$ —
Conversion of equity-based compensation to common stock upon initial public offering	$ —	$ 74,993	$ —
Income tax deconsolidation	$ 1,768	$ 10,469	$ —
Reclassification of deferred offering costs to common stock upon initial public offering	$ —	$ 11,649	$ —
Increase (decrease) in accrued capital expenditures	$ 18,344	$ 16,710	$ (23,863)
Additions to asset retirement obligations	$ 226	$ 42	$ 89
Lease liabilities arising from obtaining right-of-use assets	$ 23	$ 494	$ 3,061
Increase (decrease) in accrued equity transaction costs	$ 501	$ (341)	$ (604)
Adjustment of minority ownership puttable shares to redemption value	$ —	$ 16,989	$ 2,722
Adjustment of equity-based compensation to redemption value	$ —	$ 9,310	$ 15,602
Impact of redemption of shares issued in settlement of equity-based compensation and other on additional paid-in capital, common stock, and treasury stock	$ —	$ 2,081	$ 781
Accretion of Class B Units to redemption value	$ 1,422	$ —	$ —
Distributions payable to noncontrolling interest	$ 6,870	$ —	$ —

The accompanying notes are an integral part of these consolidated financial statements.

BKV CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY AND MEZZANINE EQUITY
(in thousands)

Table of Contents

	Equity								Mezzanine Equity				
	Common Stock		Treasury		Additional Paid-In Capital	Retained Earnings	Noncontrolling Interest	Total Equity	Common Stock		Equity-based Compensation	Noncontrolling Interest	Total Mezzanine Equity
	Shares	Amount	Shares	Amount					Shares	Amount			
Balance, December 31, 2022	**56,373**	**$ 1,132**	**193**	**$ (3,974)**	**$ 896,433**	**$ 143,006**	**$ —**	**$ 1,036,597**	**2,290**	**$ 62,712**	**$ 89,171**	**$ —**	**$ 151,883**
Net income	—	—	—	—	—	116,918	—	116,918	—	—	—	—	—
Redemption of common stock issued upon vesting of equity-based compensation	—	1	20	(604)	736	—	—	133	(21)	(2)	(602)	—	(604)
Common stock issued upon vesting of RSUs, net of shares withheld for income taxes	—	—	—	—	—	—	—	—	134	—	(2,961)	—	(2,961)
Adjustment of minority ownership puttable shares to redemption value	—	—	—	—	2,722	—	—	2,722	—	(2,722)	—	—	(2,722)
Adjustment of equity-based compensation to redemption value	—	—	—	—	(15,602)	—	—	(15,602)	—	—	15,602	—	15,602
Issuance of common stock	7,500	150	—	—	149,855	—	—	150,005	—	—	—	—	—
Shares repurchased with reverse stock split	—	—	—	(4)	—	—	—	(4)	—	—	—	—	—
Equity-based compensation	—	—	—	—	—	—	—	—	—	—	25,756	—	25,756
Balance, December 31, 2023	**63,873**	**$ 1,283**	**213**	**$ (4,582)**	**$ 1,034,144**	**$ 259,924**	**$ —**	**$ 1,290,769**	**2,403**	**$ 59,988**	**$ 126,966**	**$ —**	**$ 186,954**
Net loss	—	—	—	—	—	(142,870)	—	(142,870)	—	—	—	—	—
Adjustment of minority ownership puttable shares to redemption value	—	—	—	—	16,989	—	—	16,989	—	(16,989)	—	—	(16,989)
Adjustment of equity-based compensation to redemption value	—	—	—	—	9,310	—	—	9,310	—	—	(9,310)	—	(9,310)

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(in thousands)

Table of Contents

Redemption of common stock issued upon vesting of equity-based compensation	—	1	—	(2,077)	2,076	—	—	—	(73)	—	(2,077)	—	(2,077)
Common stock issued upon vesting of RSUs, net of shares withheld for income taxes	—	—	—	—	—	—	—	—	2,696	—	(53,239)	—	(53,239)
Redemption of common stock issued from employee stock purchase plan	—	—	1	(4)	4	—	—	—	—	(4)	—	—	(4)
Issuance of common stock upon initial public offering, net of offering costs	15,701	157	—	—	253,099	—	—	253,256	—	—	—	—	—
Mezzanine equity conversion	5,026	71	—	—	117,917	—	—	117,988	(5,026)	(42,995)	(74,993)	—	(117,988)
Income tax deconsolidation	—	—	—	—	10,469	—	—	10,469	—	—	—	—	—
Equity-based compensation	—	—	—	—	3,663	—	—	3,663	—	—	12,653	—	12,653
Balance, December 31, 2024	**84,600**	**$ 1,512**	**214**	**$ (6,663)**	**$ 1,447,671**	**$ 117,054**	**$ —**	**$ 1,559,574**	**—**	**$ —**	**$ —**	**$ —**	**$ —**
Net income	—	—	—	—	—	173,132	—	173,132	—	—	—	1,712	1,712
Contributions from noncontrolling interest	—	—	—	—	—	—	8,803	8,803	—	—	—	17,912	17,912
Distributions to noncontrolling interest	—	—	—	—	—	—	—	—	—	—	—	(1,225)	(1,225)
Changes due to consolidation of BKV-BPP Cotton Cove	—	—	—	—	—	—	(98)	(98)	—	—	—	—	—
Accretion of Class B Units to redemption value	—	—	—	—	—	(1,422)	—	(1,422)	—	—	—	1,422	1,422
Distribution declared to noncontrolling interest	—	—	—	—	—	—	—	—	—	—	—	(6,870)	(6,870)
Issuance of common stock, net	12,134	121	—	—	294,267	—	—	294,388	—	—	—	—	—
Common stock issued upon vesting of RSUs, net of shares withheld for income taxes	138	2	—	—	(1,621)	—		(1,619)	—	—	—	—	—

The accompanying notes are an integral part of these consolidated financial statements.

BKV CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY AND MEZZANINE EQUITY
(in thousands)

Table of Contents

Income tax deconsolidation	—	—	—	—	1,768	—	—	1,768	—	—	—	—	—
Equity-based compensation	—	—	—	—	12,845	—		12,845	—	—	—	—	—
Balance, December 31, 2025	**96,872**	**$ 1,635**	**214**	**$ (6,663)**	**$ 1,754,930**	**$ 288,764**	**$ 8,705**	**$ 2,047,371**	**—**	**$ —**	**$ —**	**$ 12,951**	**$ 12,951**

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.

The majority shareholder of BKV Corp is BNAC. BKV Corp's ultimate parent company is Banpu Public Company Limited ("Banpu"), a public company listed in the Stock Exchange of Thailand. As of February 27, 2026, Banpu, the ultimate parent company of BNAC and BPPUS, indirectly owned an aggregate 67.6% of BKV Corp's shares. The remaining 32.4% of shares of common stock of BKV Corp were owned by non-controlling members of management, members of the board of directors, and employee and non-employee shareholders.

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with GAAP and include the accounts for BKV Corp's wholly-owned subsidiaries and majority-owned subsidiaries in which BKV Corp has a controlling interest.

BKV Upstream Midstream, a limited liability company, was formed on May 21, 2024 and is registered in the state of Delaware. This entity is a wholly-owned subsidiary of BKV Corp. Since its formation, all of the midstream and upstream entities of BKV Corp are wholly-owned subsidiaries of BKV Upstream Midstream and include BKV Operating, LLC, BKV Barnett, LLC, BKV Chelsea, LLC (“Chelsea”), BKV Midstream, LLC, BKV North Texas, LLC, and Kalnin Ventures, LLC.

On June 14, 2024, BKV sold BKV Chaffee Corners, LLC (“Chaffee”), and on June 28, 2024, sold certain of its non-operated upstream assets in Chelsea. See *Note 3 - Acquisition and Dispositions* for further discussion.

On September 29, 2025, BKV Upstream Midstream acquired 100% of the equity interests of Bedrock Production, LLC (now known as BKV Barnett II, LLC (“BKV Barnett II”)), a Texas limited liability company (such transaction, the “Bedrock Acquisition”) from Bedrock Energy Partners, LLC (the “Seller”), pursuant to a Membership Purchase Agreement (the “Bedrock Purchase Agreement”). BKV Barnett II and its subsidiaries own certain oil and natural gas producing properties and midstream assets in the Barnett Shale. See *Note 3 - Acquisition and Dispositions* for further discussion.

Together, BKV Corp, its wholly-owned subsidiaries, and its majority-owned subsidiaries, where BKV Corp has a controlling interest and is the primary beneficiary, 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.

Business Segment Information

In accordance with Accounting Standards Codification (“ASC”) 280 - *Segment Reporting*, the Company is organized, managed, and identified as one operating segment and one reportable segment as the Company does not distinguish between business lines for the purpose of making decisions about resource allocation and performance management. The Company’s Chief Executive Officer, identified as the Chief Operating Decision Maker (“CODM”), evaluates financial performance on a consolidated basis, primarily using net income from the consolidated statements of operations. Additionally, the CODM reviews reported consolidated revenues, significant segment expenses, and other segment items as presented on the consolidated statements of operations on a monthly basis to allocate resources, manage liquidity, and assess overall Company performance relative to budget. The CODM also monitors total assets and capital expenditures, on a consolidated basis, as presented on the consolidated balance sheets and consolidated statements of cash flows, respectively.

Reclassification

Certain prior period amounts have been reclassified in order to conform to the current period presentation. These reclassifications had no impact on previously reported balance sheets, net income (loss), net cash flows, or stockholders’ equity.

Initial Public Offering

On September 27, 2024, the Company completed its initial public offering (the "IPO") of 15,000,000 shares of common stock at a price to the public of $18.00 per share. After underwriting discounts and commissions of $16.2 million, the Company received net proceeds from the offering of $253.8 million. The Company also granted the IPO underwriters a 30-day option to purchase up to 2,250,000 additional shares of common stock on the same terms. The underwriters partially exercised the option and on October 28, 2024, purchased 701,003 additional shares of common stock, resulting in additional net proceeds of $11.9 million, after deducting underwriting discounts and commissions of $0.8 million.

Upon consummation of the IPO, 5,026,638 mezzanine shares were converted into common stock.

Equity Offering

On December 3, 2025, the Company completed its public offering of 6,900,000 shares of common stock for net proceeds of $170.1 million, which were used, together with cash on hand, for the payment of the cash consideration of the purchase price in connection with BKV's acquisition of a controlling interest in BKV-BPP Power LLC and related expenses. See *Note 13 - Stockholders' Equity and Mezzanine Equity* and *Note 14 - Investments* for further detail.

Deferred Offering Costs

The Company capitalized legal and other third party fees directly related to the Company's IPO on the consolidated balance sheets, and on September 27, 2024, the Company recognized these costs as a reduction to the proceeds received from the IPO in the amount of $11.6 million.

Liquidity

As of December 31, 2025, the Company held $199.4 million of cash and cash equivalents. The Company's working capital surplus as of December 31, 2025 was $170.0 million, and for the year ended December 31, 2025, cash flows provided by operating activities was $242.7 million. The Company intends to make the payments related to its debt and investments in capital expenditures with cash flows from operations. During the year ended December 31, 2025, the Company purchased put options with several counterparties and paid a premium of $16.2 million. For further discussion on derivative transactions, see *Note 7 - Derivative Instruments*.

On September 26, 2025, BKV Upstream Midstream issued in a private placement $500.0 million of 7.50% senior unsecured notes due October 15, 2030 (the "2030 Senior Notes"). The 2030 Senior Notes were issued at par and resulted in proceeds of $490.0 million, after deducting underwriters' discounts and commissions. The proceeds were used to repay a portion of the RBL Credit Agreement and fund a portion of the purchase price of the Bedrock Acquisition, with the remainder of the purchase price being funded with shares of BKV's common stock. See *Note 4 - Debt* for further discussion on the RBL Credit Agreement and these transactions.

On September 29, 2025, BKV Upstream Midstream acquired 100% of the equity interests of BKV Barnett II from the Seller, and for the year ended December 31, 2025, paid total cash consideration of $266.5 million and transaction costs of $3.8 million. See *Note 3 - Acquisition and Dispositions* for further discussion.

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 judgments 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 assets acquired and liabilities assumed 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, its wholly-owned subsidiaries, and its majority-owned subsidiaries where BKV Corp has a controlling interest and is the primary beneficiary. 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, 2025, 2024, and 2023. 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 and

• 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 (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.

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.

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.

Restricted Cash

As of December 31, 2023, restricted cash included amounts to fund the debt service reserve account, which equaled the current portion of the Term Loan Credit Agreement plus accrued interest to comply with the Company's financial covenant under the Term Loan Credit Agreement. Due to the repayment of the Term Loan Credit Agreement during the year ended December 31, 2024, there was no restricted cash as of December 31, 2025 and 2024.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash to amounts shown in the consolidated balance sheets and consolidated statements of cash flows:

(in thousands)	December 31, 2025	December 31, 2024	December 31, 2023
Cash and cash equivalents	$ 199,412	$ 14,868	$ 25,407
Restricted cash	—	—	139,662
Total cash, cash equivalents, and restricted cash	$ 199,412	$ 14,868	$ 165,069

Inventory

Inventory primarily consists of materials and supplies and 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.

For tax years prior to the year ended December 31, 2024, the Company computed income tax expense on a separate tax return basis. During the year ended December 31, 2024, the Company deconsolidated from BNAC for federal income tax purposes and allocated tax attributes in accordance with the Code and related regulations and remained deconsolidated from BNAC throughout the year ended December 31, 2025. 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 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, 2025 and 2024. 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, 2025, 2024, and 2023, 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, 2025, 2024, and 2023.

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, 2025, 2024, and 2023, 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, 2025, 2024, and 2023.

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, 2025, 2024, and 2023.

Depreciation and amortization expense is included within depreciation, depletion, amortization, and accretion on the consolidated statements of operations. Following is a listing of useful lives for other property and equipment:

	Useful Life
Buildings	39 years
Carbon capture, utilization, and sequestration	12 years
Furniture, fixtures, equipment, vehicles, and other	5 years
Computer hardware and software	3 to 5 years
Leasehold improvements	7 to 10 years

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 with terms longer than 12-months. 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, 2025 and 2024, all of the Company's leases are accounted for as operating leases. For the years ended December 31, 2025, 2024, and 2023, total lease expense for the Company was $2.5 million, $1.2 million, and $1.7 million, respectively. These expenses are included in depreciation, amortization, depletion, and accretion in the consolidated statements of operations. 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, NGL, 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.

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, 2025, 2024, and 2023, 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.

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.

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. The Section 45Q tax credits generated after the Company's IPO are included in accounts receivable on the consolidated balance sheets. Prior to the Company's IPO, the Section 45Q tax credits were recognized as accounts receivable, related party on the consolidated balance sheets. See *Note 9 - Related Parties* for further discussion.

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, 2025 and 2024, the carrying value of the Company’s RBL Credit Agreement 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, and one 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, 2025, 2024, and 2023. 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, 2025, 2024, and 2023.

Equity-Based Compensation

The Company issues equity-based compensation in the form of restricted stock units (“RSUs”), which include time-based restricted stock units (“TRSUs”) and performance-based restricted stock units (“PRSUs”). The TRSUs the Company authorizes to grant include service conditions, and the PRSUs the Company authorizes to grant include service conditions, market performance conditions, and non-market performance conditions. There is no obligation to make any future grants, and any such grants would require approval by the Company's board of directors. For accounting purposes, the grant date fair value of the TRSUs that were granted was determined based on the trading price of BKV's common stock price on the date of grant. 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.

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. Prior to the Company’s IPO, equity-based compensation awards which ultimately settle in cash were accounted for as liabilities, and awards which were contingently settled in cash or shares of the Company’s common stock were accounted for as mezzanine equity. Mezzanine equity classified awards were carried on the consolidated balance sheets at the greater of redemption value or initial carrying value. Prior to the IPO, changes in the redemption value of the awards resulted in a transfer from stockholders’ equity to mezzanine equity on the consolidated balance sheets of the Company.

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 in the consolidated balance sheets using the cost method. Shares are held until authorized for redistribution by the Company’s board of directors.

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, and participation in the policy-making decisions of the 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 affiliate 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.

Variable Interest Entities

The Company consolidates variable interest entities in which it is the primary beneficiary in accordance with ASC 810-*Consolidation*. Generally, a variable interest entity ("VIE") is an entity with at least one of the following conditions: (i) the total equity investment at risk is insufficient to allow the entity to finance its activities without additional subordinated financial support, or (ii) the holders of the equity investment at risk, as a group, lack the characteristics of having a controlling financial interest. The primary beneficiary of a VIE is an entity that has a variable interest or a combination of variable interests that provide such entity with a controlling financial interest in the VIE. An entity is deemed to have a controlling financial interest in a VIE if it has both of the following characteristics: (i) the power to direct the activities of the VIE that most significantly impact the VIE’s economic performance, and (ii) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share attributable to BKV for each period is calculated by dividing net income (loss) attributable to BKV by the basic weighted average number of common shares outstanding during the period. Diluted net income (loss) per common share attributable to BKV is calculated by dividing net income (loss) attributable to BKV by the diluted weighted average number of common shares outstanding for the respective period. Any remeasurement of the accretion to redemption value of the Class B Units subject to possible redemption was considered to be dividends paid to the noncontrolling interest. Diluted weighted average number of common shares outstanding and the dilutive effect of potential common shares are calculated using the treasury method. The Company includes potential shares of common stock for PRSUs and TRSUs 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.

Recently Adopted Accounting Standards

In December 2023, the FASB issued ASU No. 2023-09, *Income Taxes: Improvements to Income Tax Disclosures*, which requires disaggregation of certain components included in the Company's effective tax rate and income taxes paid disclosures. The Company adopted this guidance during the year ended December 31, 2025. See *Note 17 - Income Taxes* for further detail.

Recent Accounting Pronouncements Not Yet Adopted

In November 2024, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2024-03, *Disaggregation of Income Statement Expenses*. This standard requires that entities (i) disclose amounts of purchases of inventory, employee compensation, and depreciation, depletion, and amortization, including those recognized as part of oil and gas-producing activities (or other amounts of depletion expense) included in each relevant expense caption, (ii) include certain amounts that are already required to be disclosed under current GAAP in the same disclosure as the other disaggregation requirements, (iii) disclose a qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively, and (iv) disclose the total amount of selling expenses and, in annual reporting periods, an entity's definition of selling expenses. This standard is effective January 1, 2027, with early adoption permitted. Management is currently evaluating the impact this standard will have on the Company's disclosures.

In September 2025, the FASB issued ASU 2025-06, *Targeted Improvements to the Accounting for Internal-Use Software*. Under the new standard, companies may capitalize eligible costs when (i) management has authorized and committed to funding the software project, and (ii) it is probable that the project will be completed and the software will be used to perform the function intended. The standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2027, with early adoption permitted as of the beginning of a fiscal year. The standard may be applied prospectively, retrospectively or using a modified transition approach. The Company is currently evaluating the impact that this standard will have on the Company's consolidated operating results, cash flows, financial condition, and related disclosures.

Note 3 - Acquisition and Dispositions

Asset Acquisition

On September 29, 2025 in connection with the Bedrock Acquisition, the Company paid a portion of the purchase price consisting of (i) a $37.0 million deposit retained as a holdback for any Company indemnification claims until released on the terms and conditions contained in the Bedrock Purchase Agreement, (ii) $179.5 million in cash to repay certain indebtedness of BKV Barnett II, and (iii) the issuance to the Seller of approximately 5.2 million shares of BKV Corporation common stock with such number of shares having been determined as of the date of execution of the Bedrock Purchase Agreement. On December 31, 2025, the remaining purchase price consideration paid was $50.0 million, subject to the terms and conditions of the Bedrock Purchase Agreement. The Bedrock Purchase Agreement has an economic effective date of July 1, 2025.

The Company funded the cash consideration paid at the closing of the Bedrock Acquisition, and expects to fund the remainder of the consideration payable, with proceeds from the 2030 Senior Notes, borrowings under the RBL Credit Agreement, and cash on hand. Refer to *Note 4 - Debt* for further information.

As a result of the Bedrock Acquisition, the Company acquired approximately 96,000 net acres and gas gathering lines, 1,121 producing locations with low 1- and 5-year base decline rates of approximately 7%, and nearly 1 Tcfe of proved reserves (>70% PDP reserves) using NYMEX strip pricing. The Bedrock Acquisition is expected to increase the Company's low-declining PDP reserves by over 100 MMcfe/d and enhance its inventory in the Barnett Shale, aligning with the Company's strategic position in the Fort Worth Basin.

Allocation of Purchase Price. The Bedrock Acquisition was accounted for 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 $3.8 million, were capitalized and included in the cost basis of the acquired assets. The Company completed the purchase price assessment on December 31, 2025, and paid the remaining $50.0 million adjusted purchase price consideration in accordance with the Bedrock Purchase Agreement. The stock consideration paid to Seller for the Bedrock Acquisition was valued at $124.3 million on the date of issuance (at closing) resulting in an aggregate value of consideration paid to the Seller of $394.6 million, subject to customary adjustments, including, but not limited to estimated fair value of assets acquired and liabilities assumed. See *Note 13 - Stockholders' Equity and Mezzanine Equity* for further detail on the issuance of BKV's common stock to the Seller.

Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

Consideration:		
Cash	$	266,535
Capitalized transaction costs	$	3,761
Shares of BKV Corporation's common stock		5,233,957
BKV common stock price	$	23.74
Total stock consideration	$	124,254
Total consideration	$	394,550
Assets acquired and liabilities assumed		
Accounts receivable, net	$	15,324
Commodity derivative assets, current		10,508
Developed properties		390,826
Commodity derivative assets		12,839
Other noncurrent assets		6,392
Accounts payable and accrued liabilities		(13,416)
Commodity derivative liabilities, current		(2,636)
Other current liabilities		(5,024)
Asset retirement obligations		(18,761)
Other noncurrent liabilities		(1,502)
Total net assets acquired	$	394,550

Dispositions

On June 14, 2024, the Company sold its wholly-owned subsidiary, Chaffee, representing a non-operated interest in approximately 9,800 net acres and 116.0 gross (24.2 net) wells and 122 Bcfe of proved reserves in the Marcellus Shale in the Appalachian Basin of NEPA, as well as the Company's interest in the Repsol Oil and Gas operated midstream system, for $107.8 million. The Company recognized a gain on the sale of $7.1 million, net of transaction costs of $3.5 million, which is included in the gain on sale of business in the consolidated statements of operations.

On June 28, 2024, Chelsea sold certain of its non-operated upstream assets, including interest in approximately 6,800 net acres and 214.0 gross (15.4 net) wells and 35 Bcfe of proved reserves in NEPA, for a purchase price of $24.8 million and transaction costs of $0.5 million. Due to the immateriality of the upstream assets sold, the Company utilized the practical expedient to account for the sale of Chelsea's non-operated upstream assets sold as a normal retirement with no gain or loss recognized as sale of these assets did not significantly impact the depletion rate with respect to the total reserves retained in NEPA.

Note 4 - Debt

The following table summarizes the Company's debt balances:

	December 31,	
(in thousands)	**2025**	**2024**
RBL Credit Agreement	$ —	$ 165,000
2030 Senior Notes (7.50%)	500,000	—
Unamortized debt issuance costs	(13,223)	—
Total debt, net	486,777	165,000
Less: current maturities of long-term debt	—	—
Total long-term debt, net	$ 486,777	$ 165,000

During the year ended December 31, 2024, the Company paid down the outstanding balances, including interest, and concurrently terminated the SCB Credit Facility, the Revolving Credit Agreement, and the Term Loan Credit Agreement, with proceeds from the revolving borrowings on the RBL Credit Agreement and cash on hand. Also, during the year ended December 31, 2024, due to the early termination of the Revolving Credit Agreement and the Term Loan Credit Agreement, the Company recorded a loss of $13.9 million, which was included in loss on early extinguishment of debt in the consolidated statements of operations.

2030 Senior Notes

On September 26, 2025, BKV Upstream Midstream issued in a private placement $500.0 million of the 2030 Senior Notes. The 2030 Senior Notes were issued at par and resulted in proceeds of $490.0 million, after deducting underwriters' discounts and commissions. The proceeds were used to repay a portion of the RBL Credit Agreement and fund a portion of the purchase price of the Bedrock Acquisition. In connection with the issuance of the 2030 Senior Notes, the Company paid debt issuance costs of $13.6 million, which are amortized to interest expense on the Company's consolidated statements of operations over the term of the 2030 Senior Notes. As of December 31, 2025, the effective interest rate on the 2030 Senior Notes was 8.31%.

Interest on the 2030 Senior Notes is payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2026. The 2030 Senior Notes are guaranteed on a senior unsecured basis by the Company and all of BKV Upstream Midstream's existing restricted subsidiaries and certain future subsidiaries (collectively, the "BKV Guarantors," and such guarantees, the "Guarantees"). These Guarantees are full, unconditional, joint, and several among the BKV Guarantors, subject to certain customary release provisions. At any time prior to October 15, 2027, BKV Upstream Midstream may, on any one or more occasions, redeem all or a part of the 2030 Senior Notes at a redemption price equal to 100% of the principal amount of 2030 Senior Notes redeemed, plus a "make-whole" premium and accrued and unpaid interest, if any, to, but excluding, the applicable redemption date. At any time prior to October 15, 2027, BKV Upstream Midstream may redeem up to 40% of the aggregate principal amount of 2030 Senior Notes, with an amount of cash not greater than the net cash proceeds of one or more equity offerings, at a redemption price equal to 107.500% of the principal amount of the 2030 Senior Notes redeemed, plus accrued and unpaid interest, if any, to, but excluding, the applicable redemption date, as long as at least 60% of the aggregate principal amount of 2030 Senior Notes originally issued (excluding any 2030 Senior Notes held by BKV Upstream Midstream and its subsidiaries) remains outstanding immediately after the occurrence of such redemption, and the redemption occurs within 180 days after the date of the closing of such equity offering. On or after October 15, 2027, BKV Upstream Midstream may, on any one or more occasions, redeem all or part of the 2030 Senior Notes at the redemption prices set forth below, plus accrued and unpaid interest, if any, to, but not including, the applicable redemption date, if redeemed during the 12-month period beginning on October 15 of the years indicated below:

Year	**Percentage**
2027	103.750 %
2028	101.875 %
2029 and thereafter	100.000 %

The indenture governing the 2030 Senior Notes contains covenants that limit the ability of BKV Upstream Midstream and its restricted subsidiaries to: (i) pay dividends on, purchase or redeem its capital stock or purchase or redeem certain subordinated debt; (ii) make certain investments; (iii) incur or guarantee additional indebtedness or issue certain types of preferred equity securities; (iv) create or incur certain secured debt; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of its assets; (vii) enter into agreements that restrict distributions or other payments from its restricted subsidiaries to BKV Upstream Midstream; (viii) engage in transactions with affiliates; and (ix) create or designate unrestricted subsidiaries.

The indenture governing the 2030 Senior Notes also contains customary events of default, including (i) default for 30 days in payment when due and payable of interest on the 2030 Senior Notes; (ii) default in payment when due and payable of the principal of, or premium, if any, on, the 2030 Senior Notes; (iii) cross-defaults to certain indebtedness; and (iv) certain events of bankruptcy or insolvency with respect to BKV Upstream Midstream or certain of its restricted subsidiaries. If an event of default arises from certain events of bankruptcy, insolvency or reorganization, with respect to BKV Upstream Midstream or certain of its restricted subsidiaries, all outstanding 2030 Senior Notes will become due and payable without further action or notice. If an event of default occurs and is continuing, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2030 Senior Notes may declare all the 2030 Senior Notes to be due and payable immediately.

If BKV Upstream Midstream experiences certain types of changes of control and the rating of the 2030 Senior Notes is reduced as a result thereof within 60 days, holders of the 2030 Senior Notes will be entitled to require BKV Upstream Midstream to repurchase the 2030 Senior Notes at 101% of the principal amount thereof, pursuant to an offer on the terms set forth in the indenture governing the 2030 Senior Notes.

RBL Credit Agreement

On June 11, 2024, the Company and BKV Upstream Midstream entered into the RBL Credit Agreement with BKV Upstream Midstream as the borrower and BKV Corp as a guarantor on the RBL Credit Agreement. The RBL Credit Agreement includes a maximum credit commitment of $1.5 billion. As of December 31, 2025, the RBL Credit Agreement had a borrowing base of $1.0 billion, an elected commitment of $800.0 million, and the ability to issue up to $40.0 million in letters of credit. As of March 6, 2026, $110.0 million of revolving borrowings and $15.0 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $675.0 million of available capacity thereunder for future borrowings and letters of credit.

The loans may be borrowed, repaid, and reborrowed during the term of the RBL Credit Agreement. The RBL Credit Agreement matures on June 12, 2028. The obligations under the RBL Credit Agreement are secured and guaranteed on a senior secured basis by BKV Upstream Midstream and all of BKV Upstream Midstream’s current and future material restricted subsidiaries. Loans under the RBL Credit Agreement bear interest at one, three, or six-month term SOFR or an ABR, as applicable, plus a credit spread adjustment of 0.10% for SOFR borrowings, plus an applicable margin per annum. Interest is payable on the last day of each interest period and at maturity. BKV Upstream Midstream is obligated to pay certain fees to the lenders and administrative agent under the RBL Credit Agreement, including commitment fees on the average daily amount of the undrawn portion of the commitments. During the years ended December 31, 2025 and 2024, BKV Upstream Midstream recognized $2.5 million and $0.8 million, respectively, of commitment fees, which are included in interest expense on the consolidated statements of operations.

The RBL Credit Agreement contains various restrictive covenants that, among other things, limit BKV Upstream Midstream's ability and the ability of its restricted subsidiaries to, subject to certain exceptions: (i) incur indebtedness; (ii) incur liens; (iii) acquire or merge with any other company; (iv) sell assets or equity interests of its subsidiaries; (v) make investments; (vi) pay dividends or make other restricted payments; (vii) change its lines of business; (viii) enter into certain hedge agreements; (ix) enter into transactions with affiliates; (x) own any subsidiary that is not organized in the United States; (xi) prepay any unsecured senior or subordinated indebtedness; (xii) engage in certain marketing activities; and (xiii) allow, on a net basis, gas imbalances, take-or-pay, or other prepayments with respect to proved oil and gas properties.

The RBL Credit Agreement requires BKV Upstream Midstream to always hedge not less than 50% of reasonably anticipated projected production from our proved developed producing reserves for the subsequent 24 calendar month period immediately following the date financial statements are required to be delivered under the RBL Credit Agreement for each fiscal quarter.

The RBL Credit Agreement also includes financial covenants that require BKV Upstream Midstream to maintain:

- on a quarterly basis, a minimum Current Ratio (as defined in the RBL Credit Agreement) of no less than 1.00 to 1.00; and
- on a quarterly basis, a Net Leverage Ratio (as defined in the RBL Credit Agreement) of no greater than 3.25 to 1.00.

The RBL Credit Agreement includes customary equity cure rights that will enable BKV Upstream Midstream to cure certain breaches of the minimum current ratio covenant or the maximum net leverage ratio covenant (subject to certain limitations in the RBL Credit Agreement). As of December 31, 2025, BKV Upstream Midstream was in compliance with such covenants in the RBL Credit Agreement.

The RBL Credit Agreement generally includes customary events of default for a reserve-based credit facility, some of which allow for an opportunity to cure. 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. The RBL Credit Agreement is secured by substantially all of BKV Upstream Midstream's assets and those of the guarantors, and upon an event of default the agent under the RBL Credit Agreement could commence foreclosure proceedings.

Financing costs related to the RBL Credit Agreement are deferred and capitalized as debt issuance costs and are included within other assets on the consolidated balance sheets. During the years ended December 31, 2025 and 2024, BKV paid debt issuance costs of $2.3 million and $8.1 million, respectively, which are amortized to interest expense on the Company's consolidated statements of operations over the term of the RBL credit agreement. As of December 31, 2025 and 2024, $6.9 million of unamortized debt issuance costs remained outstanding for both periods. As of December 31, 2025, the RBL Credit Agreement had a zero balance and the outstanding letters of credit were $15.0 million. As of December 31, 2024, the effective interest rate on the RBL Credit Agreement was 7.50%, and the outstanding letters of credit were $14.1 million.

Subordinated Intercompany Loan Agreement

On June 18, 2024, the Company paid down $25.0 million of the $75.0 million outstanding on the related party loan with BNAC, including interest, and on September 30, 2024, the Company repaid the outstanding balance of $50.0 million, including interest, with proceeds from the IPO.

Note 5 - Natural Gas Properties & Other Property and Equipment

As of December 31, 2025 and 2024, accumulated depreciation, depletion, and amortization for developed natural gas properties was $825.7 million and $697.0 million, respectively. Depreciation, depletion, and amortization expense for developed natural gas properties was $128.7 million, $188.7 million, and $196.1 million for the years ended December 31, 2025, 2024, and 2023, respectively.

Midstream assets consisted of the following:

	December 31,	
(in thousands)	**2025**	**2024**
Compressor station	$ 33,752	$ 33,461
Meter station	67	67
Pipelines	244,155	243,116
Total	277,974	276,644
Accumulated depreciation	(23,770)	(17,285)
Midstream assets, net	$ 254,204	$ 259,359

Depreciation expense on midstream assets was $6.4 million, $6.9 million, and $7.5 million for the years ended December 31, 2025, 2024, and 2023, respectively.

Other property and equipment consisted of the following:

(in thousands)	December 31, 2025	December 31, 2024
Carbon capture, utilization, and sequestration	$ 114,261	$ 69,743
Buildings	6,746	15,707
Furniture, fixtures, equipment, and vehicles	22,408	19,306
Computer software	8,461	5,595
Leasehold improvements	1,685	1,685
Land	3,090	3,090
Construction in process	6,350	3,575
Total	163,001	118,701
Accumulated depreciation	(25,262)	(21,401)
Other property and equipment, net	$ 137,739	$ 97,300

Depreciation expense for other property and equipment was $5.7 million, $6.4 million, and $5.7 million for the years ended December 31, 2025, 2024, and 2023, respectively. During the year ended December 31, 2025, the Company received proceeds on the sale of other properties and equipment of $6.9 million, which included the sale of the Bridgeport field office of $5.5 million, less transaction costs of $0.4 million, and recognized a loss on sale of these properties and equipment of $1.8 million, which is included in the gains (losses) on sales of assets, net in the consolidated statements of operations. During the year ended December 31, 2024, the Company received proceeds on the sale of other properties of $5.0 million, and recognized a gain on sale of these properties of $3.6 million, which is included in the gains (losses) on sales of assets, net in the consolidated statements of operations. During the year ended December 31, 2023, the Company received proceeds on the sale of other properties of $6.7 million, and recognized a gain on sale of these properties of $2.2 million, which is included in the gains (losses) on sales of assets, net, in the consolidated statements of operations.

Write-Off of ERP System

During the year ended December 31, 2025, the Company was actively implementing a new enterprise resource planning ("ERP") system and had capitalized $6.9 million in software costs. However, during the third quarter of 2025, the Company decided to discontinue implementation of this ERP system and wrote off $5.6 million of capitalized software costs, which is included in other operating expense in the consolidated statements of operations, as the system was determined to no longer align with the Company's operational and strategic needs. The Company is in the process of implementing a new ERP system that better supports its business processes and long-term objectives.

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, 2025 and 2024, the impact of the non-performance risk adjustment to the Company's fair value of commodity derivative liabilities was $1.6 million and $6.6 million, respectively.

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:

	December 31, 2025		
	Fair Value Measurements Using:		
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets			
Derivative instruments	$ 88,214	$ —	$ 88,214
Financial liabilities			
Derivative instruments	5,767	—	5,767

(in thousands)	December 31, 2024 Fair Value Measurements Using: Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial liabilities			
Derivative instruments	$ 67,634	$ —	$ 67,634

The contingent consideration was generated from the Devon Barnett Acquisition and on January 8, 2025, the Company paid the final 2024 contingent consideration of $20.0 million, which is reflected as contingent consideration payable within current liabilities on the consolidated balance sheets. The Devon Barnett Acquisition and the Exxon Barnett Acquisition contingencies are described further in *Note 16 - Commitments and Contingencies*. The Devon Barnett Acquisition was accounted for as an asset acquisition with the contingent consideration meeting the criteria of a derivative in accordance with ASC 815 - *Derivatives and Hedging*. See *Note 7 - Derivative Instruments* for further discussion.

The minority ownership puttable shares from the 2021 Plan (as defined in *Note 13 - Stockholders' Equity and Mezzanine Equity*) were recorded at fair value upon initial recognition in mezzanine equity, and its common stock was valued using both observable (Level 2) and unobservable (Level 3) inputs. Subsequent to the Company's IPO, the minority ownership puttable shares were converted to common stock. The minority ownership puttable shares are further described in *Note 13 - Stockholders' Equity and Mezzanine Equity*.

Equity-based compensation from the 2021 Plan was 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. Prior to the Company's IPO, the remaining components of the awards were valued based on the fair market value of the common stock of the Company, determined using the same valuation methodologies applied to the minority ownership puttable shares. Equity-based compensation is further described in *Note 13 - Stockholders' Equity and Mezzanine Equity*.

There was no Level 3 activity for the year ended December 31, 2025. The tables below sets forth the changes in the Company's Level 3 fair value measurements:

(in thousands)	Year Ended December 31, 2024 Contingent Consideration	Minority Ownership	Equity-Based Compensation	Total
Balance, beginning of period	$ 29,676	$ 59,988	$ 126,966	$ 216,630
Contingent consideration - settled	(20,000)	—	—	(20,000)
Mezzanine equity conversion	—	(42,995)	(74,993)	(117,988)
Grant date fair value of equity-based compensation, pre-IPO	—	(4)	(42,663)	(42,667)
Change in fair market value (all instruments)	(9,676)	(16,989)	(9,310)	(35,975)
Balance, end of period	$ —	$ —	$ —	$ —

(in thousands)	Year Ended December 31, 2023 Contingent Consideration	Minority Ownership	Equity-Based Compensation	Total
Balance, beginning of period	$ 88,051	$ 62,712	$ 89,171	$ 239,934
Contingent consideration - settled	(20,000)	—	—	(20,000)
Grant date fair value of equity-based compensation, pre-IPO	—	(2)	22,193	22,191
Change in fair market value (all instruments)	(38,375)	(2,722)	15,602	(25,495)
Balance, end of period	$ 29,676	$ 59,988	$ 126,966	$ 216,630

Other Fair Value Measurements

The carrying value of cash and cash equivalents, accounts receivable, net, and accounts payable and accrued liabilities approximate their fair values due to the short-term maturities of these instruments. Long-term debt obligations under the RBL Credit Agreement also approximate fair value because the variable rates of interest are market-based. The fair value of the 2030 Senior Notes as of December 31, 2025 was approximately $507.5 million based on quoted market prices from banks and are classified Level 2 in the fair value hierarchy. The 2030 Senior Notes are carried on the consolidated balance sheets at its original issuance value, as adjusted over time to accrete that value to par.

Note 7 - Derivative Instruments

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 Company also determined that the contingent consideration generated from the Devon Barnett Acquisition met the definition of a derivative in accordance with ASC 815 - *Derivatives and Hedging*, and the fair value of the contingent consideration was $20.0 million as of December 31, 2024, and is included in contingent consideration payable in the consolidated balance sheets. The change in the fair value of this contingent consideration was a gain of $7.5 million and $25.0 million for the years ended December 31, 2024 and 2023, respectively, and is included in gains on contingent consideration liabilities on the consolidated statements of operations. See *Note 16 - Commitments and Contingencies* for further discussion.

The derivative contracts outstanding as of December 31, 2025 consisted of commodity swaps, basis swaps, put and call options, and producer 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:

(in thousands)	Balance Sheet Location	December 31, 2025 Gross Amounts of Assets and Liabilities	Offset Adjustments	Net Amounts of Assets and Liabilities
Current derivative assets	Commodity derivative assets, current	$ 64,669	$ (2,887)	$ 61,782
Noncurrent derivative assets	Commodity derivative assets	34,116	(7,684)	26,432
Current derivative liabilities	Commodity derivative liabilities, current	2,887	(2,887)	—
Noncurrent derivative liabilities	Commodity derivative liabilities	13,451	(7,684)	5,767

(in thousands)	Balance Sheet Location	December 31, 2024 Gross Amounts of Assets and Liabilities	Offset Adjustments	Net Amounts of Assets and Liabilities
Current derivative assets	Commodity derivative assets, current	$ 5,187	$ (5,187)	$ —
Noncurrent derivative assets	Commodity derivative assets	872	(872)	—
Current derivative liabilities	Commodity derivative liabilities, current	25,464	(5,187)	20,277
Noncurrent derivative liabilities	Commodity derivative liabilities	48,229	(872)	47,357

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.

Derivative Contracts

The following tables set forth the derivative gains (losses), net on the consolidated statements of operations:

(in thousands)	Year Ended December 31, 2025	2024	2023
Gain (loss) on settled derivatives, net	$ (8,083)	$ 112,527	$ 90,179
Gain (loss) on unsettled derivatives, net	113,164	(146,679)	148,564
Derivative gains (losses), net	$ 105,081	$ (34,152)	$ 238,743

There were no early-terminated natural gas commodity derivative swap contracts during the year ended December 31, 2025. Settled derivative gains, net for the year ended December 31, 2024, includes gains of $13.3 million related to the termination of certain natural gas commodity derivative swap contracts prior to their contractual settlement dates. $8.4 million of such gains is attributable to early-terminated natural gas commodity derivative swap contracts covering production during the year ended December 31, 2024. Settled derivative gains, net for the year ended December 31, 2023 includes gains of $46.7 million related to the termination of certain natural gas commodity derivative swap contracts prior to their contractual settlement dates. $39.1 million of such gains is attributable to early-terminated natural gas commodity derivative swap contracts covering production during the year ended December 31, 2023.

During the first quarter in 2024, the Company entered into an agreement to sell a call option and subsequently received a net premium of $23.5 million for contracts that settle in 2026 and 2027. The call option has an established ceiling price of

$5.00 per MMBtu. If at the time of settlement the contracted settlement price exceeds the ceiling price, the Company pays the counterparty an amount equal to the difference between the contracted settlement price and the ceiling price multiplied by the contract volumes. The premium received was recorded as a liability and is subsequently adjusted to the current fair value of the option written. During the fourth quarter of 2025, the Company terminated a portion of the call option contracts scheduled to settle in 2026 in exchange for natural gas fixed-price swap contracts that will settle in 2026. No realized gain or loss was recognized on this transaction.

During the first quarter in 2025, the Company entered into agreements to buy put options and subsequently paid a net premium of $16.2 million for contracts that settle in 2026 and 2027. The put options have an established floor of $3.00 per MMBtu. If at the time of settlement the contracted settlement price falls below the floor, the counterparties pay the Company an amount equal to the difference between the contracted settlement price and the floor multiplied by the contract volumes. The premium paid was recorded as an asset and is subsequently adjusted to the current fair value of the option written. During the fourth quarter of 2025, the Company terminated a portion of the put option contracts scheduled to settle in 2026 in exchange for natural gas fixed-price swap contracts that will settle in 2026. No realized gain or loss was recognized on this transaction.

Volume of Derivative Activities

As of December 31, 2025, 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, 2025 (in thousands)
2026					
Swap	154,460,650	$ 3.86			$ 35,268
2027					
Swap	79,825,383	$ 4.03			$ 11,938
Collars	37,662,319		$ 3.57	$ 4.00	$ (3,225)
Call options	36,500,000			$ 5.00	$ (9,372)
Put options	36,500,000		$ 3.00		$ 7,014
2028					
Swap	51,995,323	$ 3.93			$ 11,480

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, 2025 (in thousands)
2026				
Swap	Transco Leidy Basis	43,800,000	$ (0.80)	$ 238
Swap	HSC Basis	54,750,000	$ (0.32)	$ 7,408
Swap	Transco St 85 (Z4) Basis	36,500,000	$ 0.62	$ 4,225
Swap	NGPL TXOK Basis	47,521,249	$ (0.36)	$ 3,384
2027				
Swap	Transco Leidy Basis	7,300,000	$ (0.77)	$ 36
Swap	HSC Basis	7,300,000	$ (0.25)	$ 458
Swap	NGPL TXOK Basis	16,965,270	$ (0.31)	$ (93)
2028				
Swap	HSC Basis	10,980,000	$ (0.17)	$ 289

The following table represents natural gas liquids commodity derivatives for contracts, by contract type, expiring through December 31, 2027, based on the applicable index listed below:

Instrument	Commodity Reference Price	Gallons	Weighted Average Price (USD)		Fair Value as of December 31, 2025 (in thousands)	
2026						
Swap	OPIS Purity Ethane Mont Belvieu	142,691,481	$	0.25	$	468
Swap	OPIS IsoButane Mont Belvieu Non-TET	10,075,218	$	0.83	$	185
Swap	OPIS Normal Butane Mont Belvieu Non-TET	16,928,342	$	0.80	$	836
Swap	OPIS Propane Mont Belvieu Non-TET	59,163,120	$	0.69	$	4,359
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	25,835,930	$	1.37	$	5,411
2027						
Swap	OPIS Purity Ethane Mont Belvieu	79,965,970	$	0.28	$	935
Swap	OPIS IsoButane Mont Belvieu Non-TET	2,732,077	$	0.76	$	21
Swap	OPIS Normal Butane Mont Belvieu Non-TET	4,873,274	$	0.74	$	92
Swap	OPIS Propane Mont Belvieu Non-TET	15,478,884	$	0.64	$	309
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	6,777,531	$	1.26	$	783

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, 2025 and 2024, the liability has been accreted to its present value and, for the years ended December 31, 2025, 2024, and 2023, accretion expense of $15.1 million, $14.1 million, and $13.2 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:

	Year Ended December 31,					
(in thousands)	**2025**		**2024**		**2023**	
Balance, as of January 1,	$	201,158	$	195,476	$	182,300
Additions through acquisitions [1]		18,761		—		640
Liabilities incurred		226		42		89
Liabilities settled		(1,873)		(1,288)		(759)
Liabilities associated with property sold [2]		—		(7,133)		—
Accretion of discount		15,067		14,061		13,206
Balance, as of December 31,		233,339		201,158		195,476
Less current portion		(2,967)		(2,363)		(2,271)
Asset retirement obligations, long-term	$	230,372	$	198,795	$	193,205

(1) Relates to the Bedrock Acquisition. See *Note 3 - Acquisition and Dispositions* for further discussion.

(2) Liabilities associated with property sold relate to the sales of Chaffee and certain non-operated upstream assets in Chelsea. See *Note 3 - Acquisition and Dispositions* for further discussion.

Note 9 - Related Parties

The Company has a loan agreement with Temple Generation I LLC (the "Power Plant"), a wholly-owned subsidiary of BKV-BPP Power LLC (see *Note 14 - Investments* for further discussion on BKV-BPP Power LLC). This loan agreement allows 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%. On June 13, 2023 and June 20, 2023, BKV-BPP Power LLC drew down $3.0 million and $5.0 million, respectively. On July 10, 2023, BKV-BPP Power LLC repaid the $8.0 million, including accrued interest. During the year ended December 31, 2024, the Company recognized zero interest income on the Power Plant Loan, and during the year ended December 31, 2023, the Company recognized interest income on the Power Plant Loan of an immaterial amount. The Power Plant Loan expired on November 30, 2023 and was not renewed.

On March 10, 2022, the Company entered into a loan agreement with BNAC and borrowed $75.0 million thereunder. 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. Interest on the outstanding principal was SOFR plus an interest rate margin of 5.25%. During the year ended December 31, 2024, the Company repaid the outstanding balance of $75.0 million, including interest, and subsequently terminated the related party loan with BNAC with proceeds from the revolving borrowings on the RBL Credit Agreement and the IPO. For the years ended December 31, 2024 and 2023, interest expense recognized on this loan agreement was $5.2 million and $7.1 million, respectively.

Prior to the consummation of the IPO, the Company filed its income tax returns as part of BNAC. Accordingly, Section 45Q tax credits generated by the Barnett Net Zero Project were recognized by BNAC but attributable to the Company. For the years ended December 31, 2024 and 2023, the Company recognized $14.0 million, and $0.7 million, respectively, of income related to the Section 45Q tax credits, and as of December 31, 2025 and 2024, the Company had receivables of $10.8 million and $14.7 million, respectively, from BNAC related to those Section 45Q tax credits, which is included in accounts receivable, related parties on the consolidated balance sheets. Separately, as of December 31, 2025 and 2024, the Company had payables of $0.8 million and $1.4 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. In addition, as of December 31, 2025 and 2024, the Company had a receivable from BNAC of $0.4 million and $0.2 million, respectively, related to shared general and administrative expenses, which is included in accounts receivable, related parties on the consolidated balance sheets.

As of December 31, 2025 and 2024, the Company had accounts receivable from BKV-BPP Power LLC of $0.4 million and $0.5 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 - Investments* for further discussion of the ASA and the Company’s equity method investments. During the years ended December 31, 2025, 2024, and 2023, the Company recognized $1.8 million, $3.1 million, and $3.6 million, respectively, of income related to the services provided under the ASA, which is included in related party revenue on the consolidated statements of operations.

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, 2025		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 67,668	$ 607,410	$ 675,078
NGLs	—	173,059	173,059
Oil	—	9,460	9,460
Total natural gas, NGL, and oil sales	$ 67,668	$ 789,929	$ 857,597
Marketing revenues	—	12,304	12,304
Midstream revenues	—	10,456	10,456
Related party and other	—	13,424	13,424
Total	$ 67,668	$ 826,113	$ 893,781

(in thousands)	Year Ended December 31, 2024 Pennsylvania	Texas	Total
Natural gas	$ 38,795	$ 346,661	$ 385,456
NGLs	—	165,508	165,508
Oil	—	6,606	6,606
Total natural gas, NGL, and oil sales	$ 38,795	$ 518,775	$ 557,570
Marketing revenues	—	10,668	10,668
Midstream revenues	2,014	10,546	12,560
Related party and other	—	23,732	23,732
Total	$ 40,809	$ 563,721	$ 604,530

(in thousands)	Year Ended December 31, 2023 Pennsylvania	Texas	Total
Natural gas	$ 57,678	$ 452,168	$ 509,846
NGLs	—	187,860	187,860
Oil	—	8,445	8,445
Total natural gas, NGL, and oil sales	$ 57,678	$ 648,473	$ 706,151
Marketing revenues	—	8,710	8,710
Midstream revenues	4,635	11,533	16,168
Related party and other	—	8,251	8,251
Total	$ 62,313	$ 676,967	$ 739,280

As of December 31, 2025 and 2024, the Company's receivables from contracts with customers were $76.8 million and $45.8 million, respectively.

Note 11 - Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities included in current liabilities consist of the following:

(in thousands)	December 31, 2025	2024
Accounts payable	$ 84,406	$ 53,238
Accrued payroll	29,411	23,435
Oil and gas production and other taxes payable	21,604	21,263
Commodity derivative settlements payable	24,705	3,891
Revenues payable	36,310	17,921
Other accrued liabilities	10,498	1,618
Total	$ 206,934	$ 121,366

Note 12 - Equity-Based Compensation

2024 Equity and Incentive Compensation Plan

The Company's 2024 Equity and Incentive Compensation Plan (the “2024 Plan”) became effective immediately prior to the consummation of the IPO and in December 2025, the Company's board of directors approved an amendment and restatement of the 2024 Plan to increase the number of shares of common stock available for grant and issuance under the 2024 Plan by 2,500,000 shares, effective March 5, 2026 (the 2024 Plan, as so amended and restated, the “A&R 2024 Plan”). The A&R 2024 Plan was also approved by holders of a majority of the voting power of the Company's outstanding capital stock in January 2026.

The A&R 2024 Plan permits the grant of awards to the non-employee directors, officers, and other employees of BKV Corp and its controlled subsidiaries in order to provide incentives and rewards for service and/or performance. The Company 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 the Company's common stock. Under the A&R 2024 Plan, the Company can issue up to 7,500,000 shares of its common stock, which are subject to adjustment to reflect any extraordinary cash dividend, stock dividend, split, or combination of the Company's common stock. The aggregate number of shares of the Company's common stock available for award under the A&R 2024 Plan will be reduced by one share of the Company's common stock for every one share of its common stock subject to an award granted under the A&R 2024 Plan. Each grant of an award under the A&R 2024 Plan will be evidenced by an award agreement that includes terms and provisions, determined by the Company's Compensation Committee (or other committee of the board of directors designated by the board to administer the A&R 2024 Plan), which outlines the number of shares of common stock, earning or vesting terms, and any other terms consistent with the A&R 2024 Plan.

Any shares of common stock awarded under the A&R 2024 Plan that have been canceled, forfeited, expired, settled for cash shares, or is unearned (in whole or part) will be added back to the aggregate number of shares of common stock available under the A&R 2024 Plan, with the exception of the following: (i) shares of common stock withheld by the Company in payment of the exercise price of a stock option; (ii) shares of common stock tendered or otherwise used in payment of the exercise price of a stock option; (iii) shares of common stock withheld by the Company or tendered or otherwise used to satisfy a tax withholding obligation; (iv) shares of 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 common stock reacquired by the Company on the open market or otherwise using cash proceeds from the exercise of stock options. As of December 31, 2025, 2,685,601 shares were available for future grants under the 2024 Plan. As of March 5, 2026, 4,713,922 shares were available for future grants under the A&R 2024 Plan.

Performance-Based Restricted Stock Units

On September 27, 2024, the Company granted 704,649 PRSUs under the 2024 Plan that cliff vest on December 31, 2026, and are subject to a performance period beginning January 1, 2024 and ending on December 31, 2026. During the year ended December 31, 2025, the Company granted 670,181 PRSUs, which cliff vest on December 31, 2027, and are subject to a performance period beginning January 1, 2025 and ending on December 31, 2027, (collectively with the PRSU grants issued in 2024, the “PRSU Performance Period”). The table below summarizes the PRSU activity for the year ended December 31, 2025:

(in thousands, except per share amounts)	**Shares**	**Weighted Average Grant Date Fair Value**
Unvested PRSUs as of January 1, 2025	703	$ 12.23
Granted	670	$ 19.44
Vested	(52)	$ 12.92
Forfeitures	(136)	$ 14.14
Unvested PRSUs as of December 31, 2025	1,185	$ 16.06

These PRSUs are eligible to be earned based on three performance conditions: (i) annualized Total Shareholder Return (“aTSR”) of the Company's common stock during the PRSU Performance Period, weighted at 30%, (ii) relative Total Shareholder Return (“rTSR”) of the common stock of the Company's benchmark group during the PRSU Performance Period, weighted at 30%, and (iii) Return on Capital Employed (“ROCE”) based on the average annual performance over the PRSU Performance Period, weighted at 40%.

The aTSR and rTSR components of the awards are market-based conditions valued using the Monte-Carlo Simulation pricing model, which calculates multiple potential outcomes and establishes grant date fair value based on the most likely outcome. ROCE is considered to be a non-market performance condition. Thus, the likelihood of achievement must be reassessed at every reporting period, and compensation expense is adjusted accordingly. As of December 31, 2025, management estimates ROCE performance for the post IPO grants issued during the year ended December 31, 2024 to be lower than the target performance by approximately 2.1%, and for the grants that were issued during the year ended December 31, 2025 to be higher than the target performance level by approximately 55.4%. The grant date fair value of the PRSUs presented in the activity for the years ended December 31, 2025 and 2024, takes into account the grant date fair value for ROCE, 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 fair value was estimated using the following assumptions for the PRSUs granted for the years ended December 31, 2025 and 2024:

	Year ended December 31,	
	2025 [1]	2024
Volatility [2]	40 %	40 %
Expected dividend rate	— %	— %
Risk free rate	3.9 %	3.5 %
aTSR weighted average grant date value	$ 14.39	$ 6.78
rTSR weighted average grant date value	$ 23.90	$ 9.91
ROCE	$ 19.89	$ 18.05
Expected term	3 years	3 years

(1) There were four specific grant dates during the year ended December 31, 2025. Amounts shown represent weighted average.
(2) Volatility uses a combination of daily historical and implied volatility over a look back period commensurate with the remaining term of the assets.

As of December 31, 2025, there was $14.6 million of unrecognized compensation expense related to the PRSU awards, which will be amortized over a weighted average period of 1.5 years.

Equity-based compensation related to PRSUs was $8.1 million and $0.8 million for the years ended December 31, 2025 and 2024, respectively, which is included in general and administrative expenses in the consolidated statements of operations.

Time-Based Restricted Stock Units

On September 27, 2024, the Company granted 469,835 TRSUs under the 2024 Plan, and during the year ended December 31, 2025, the Company granted 469,734 TRSUs under the 2024 Plan. Under the applicable provisions of the 2024 Plan, the TRSU incentive award vests annually over three anniversary dates in equal portions with the first tranche vesting on January 1, 2025, subject to continued employment with the Company and board of director approval. The table below summarizes the TRSU activity for the year ended December 31, 2025:

(in thousands, except per share amounts)	Shares	Weighted Average Grant Date Fair Value
Unvested TRSUs as of January 1, 2025	469	$ 18.05
Granted	470	$ 20.11
Vested	(156)	$ 18.05
Forfeited	(94)	$ 18.51
Unvested TRSUs as of December 31, 2025	689	$ 19.39

As of December 31, 2025, there was $8.7 million of unrecognized compensation expense related to the TRSU awards, which will be amortized over a weighted average period of 1.7 years.

Equity-based compensation related to TRSUs was $4.7 million and $2.8 million for the years ended December 31, 2025 and 2024, respectively, which is included in general and administrative expenses in the consolidated statements of operations.

Employee Stock Purchase Plan

The Company's Employee Stock Purchase Plan (the “ESPP”) became effective immediately prior to the consummation of the IPO. A total of 500,000 shares of the Company's common stock are available for awards under the ESPP and eligible employees are only permitted to purchase shares of the Company's common stock through payroll deductions, which cannot exceed 10% of the employee's eligible compensation. 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 the Company's common stock. For the year ended December 31, 2025, the Company recognized equity-based compensation expense related to the ESPP of $0.1 million, which is included in general and administrative expenses in the consolidated statements of operations.

2021 Equity and Incentive Compensation Plan

On January 1, 2021, the BKV Corporation Long-Term Incentive Plan (the "2021 Plan") was established. Upon consummation of the IPO, 7,724,499 RSUs were considered to have been granted under ASC 718 - *Compensation-Stock Compensation* ("ASC 718"), when taking into consideration PRSUs at the maximum performance level and TRSUs anticipated to be legally granted in the three years following inception. As of December 31, 2024, the awards considered granted under ASC 718 since inception equaled the number of RSUs legally granted. Prior to the Company's IPO, RSUs under the 2021 Plan were recognized in mezzanine equity on the consolidated statements of stockholders' equity and mezzanine equity, and were valued using unobservable inputs. See *Note 6 - Fair Value Measurements* for further detail.

Performance-Based Restricted Stock Units

PRSUs cliff vest and were subject to a vesting or performance period beginning January 1, 2021 and ending on December 31, 2023 (the "Performance Period"). As of December 31, 2023, or the Performance Period, the Company achieved its goals as follows: TSR met its threshold at 136%, ROCE met its threshold at 131%, and IPO readiness met its threshold at 200%. In February 2024, the Plan's committee approved the Company's goals and the PRSUs outstanding as of December 31, 2023, vested with some being forfeited prior to the Plan's approval. The following table summarizes the PRSU activity under the 2021 Plan for the year ended December 31, 2024:

(in thousands, except per share amounts)	**Shares**	**Weighted Average Grant Date Fair Value**
Unvested PRSUs as of January 1, 2024	3,967	$ 19.02
Vested [(1)]	(3,963)	$ 19.02
Forfeited [(2)]	(4)	$ 19.02
Unvested PRSUs as of December 31, 2024	—	$ —

(1) For the year ended December 31, 2024, the total weighted average fair value of the shares vested was $28.25.
(2) Forfeited award amounts took into consideration performance shares at the maximum performance level.

Due to the PRSU cliff vest, there was no equity-based compensation under the 2021 Plan for the years ended December 31, 2025 and 2024. For the year ended December 31, 2023, equity-based compensation related to the PRSUs was $22.2 million. This cost is included in general and administrative expenses in the consolidated statements of operations.

Time-Based Restricted Stock Units

The following table summarizes the TRSU activity under the 2021 Plan for the year ended December 31, 2024:

(in thousands, except per share amounts)	**Shares**	**Weighted-Average Grant Date Fair Value**
Unvested TRSUs as of January 1, 2024	727	$ 22.37
Vested [(1)]	(659)	$ 22.12
Forfeited	(68)	$ 22.12
Unvested TRSUs as of December 31, 2024	—	$ —

(1) For the year ended December 31, 2024, the total weighted average fair value of the shares vested was $22.34.

For the years ended December 31, 2024 and 2023, equity-based compensation expense related to the TRSUs under the 2021 Plan was $12.7 million and $3.6 million, respectively, which is included in general and administrative expenses in the consolidated statements of operations. Upon consummation of the IPO, the remaining TRSUs from the 2021 Plan vested.

Note 13 - Stockholders' Equity and Mezzanine Equity

Reverse Stock Split

On October 30, 2023, the Company completed a one-for-two reverse stock split. As a result of the reverse stock split, every two shares of outstanding common stock were combined and now represent one share of common stock and fractional shares were paid out in cash to the common stockholders, which amounted to an immaterial amount. No fractional shares were issued in connection with the reverse stock split.

Equity Offerings

On December 3, 2025, the Company completed its public offering of 6,900,000 shares of common stock at a price to the public of $26.00 per share, for gross proceeds of $179.4 million. After underwriting discounts and commissions of $9.3 million, the Company received net proceeds from the offering of $170.1 million. The offering costs were recorded as a reduction to additional paid-in capital. BKV used the net proceeds from the offering, together with cash on hand, for the payment of the cash consideration of the purchase price in connection with BKV's acquisition of a controlling interest in BKV-BPP Power LLC and related expenses.

As part of the Bedrock Acquisition, the Company issued 5,233,957 shares of BKV's common stock to the Seller at a closing price of $23.74 at September 29, 2025. In accordance with the Bedrock Purchase Agreement, the number of shares issued was determined by dividing $110.0 million by $21.0166, the volume weighted average price of BKV common stock during the 20 consecutive trading-day period ending August 7, 2025. As of September 29, 2025 the date of the Bedrock Acquisition, the fair value of stock consideration was $124.3 million. Issuance costs related to the Bedrock Acquisition of $0.3 million were recorded as a reduction to additional paid-in capital. See *Note 3 - Acquisition and Dispositions* for further detail on the Bedrock Acquisition.

On September 27, 2024, the Company completed its IPO of 15,000,000 shares of common stock at a price to the public of $18.00 per share. After underwriting discounts and commissions of $16.2 million, the Company received net proceeds from the offering of $253.8 million. The Company also granted the IPO underwriters a 30-day option to purchase up to 2,250,000 additional shares of common stock on the same terms. The underwriters partially exercised the option and on October 28, 2024, purchased 701,003 additional shares of common stock, resulting in additional net proceeds of $11.9 million, after deducting underwriting discounts and commissions of $0.8 million.

Upon consummation of the IPO, 5,026,638 mezzanine shares were converted into common stock.

On September 27, 2023, the Company made a capital call on BNAC of $150.0 million, and pursuant to the requirements of the existing stockholders' agreement, BNAC made a capital contribution in exchange for 7,500,000 shares of BKV common stock. To comply with a financial covenant under the Term Loan Credit Agreement, $138.3 million of BNAC's capital contribution was placed in a debt service reserve account, which was released upon termination of the Term Loan Credit Agreement. See *Note 2 - Summary of Significant Accounting Policies* for further information.

Common Shares Issued and Outstanding

As of December 31, 2025 and 2024, the Company had 96,871,868 and 84,600,301, 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, 2025, 2024, and 2023.

There were no cash dividends declared or paid during the years ended December 31, 2025, 2024, and 2023.

Minority Ownership Puttable Shares — Mezzanine Equity

On May 1, 2020, the Company issued 47,350,000 shares, of which, 1,114,385 shares were issued to certain non-controlling management shareholders of BKV as a part of a series of acquisitions, including the corporate restructuring of BKV Corp, and 1,000,000 shares were issued as part of the merger with Kalnin Ventures LLC (collectively, the "Management Shares"). As of December 31, 2023, there were 1,976,689 of these minority shares outstanding. Upon consummation of the IPO, all Management Shares were converted into common stock. The Management Shares included a put and call feature which required BKV to repurchase shares from these shareholders upon the occurrence of certain events stipulated in the Stockholders' Agreement at either $20.00 per share or the fair market value per share, depending on the type and timing of the triggering event. In addition, BKV had the right to call and repurchase the Management Shares upon the occurrence of certain events stipulated in the Stockholders' Agreement at either $20.00 per share or the fair market value per share, depending on the type and timing of the triggering event. Since the shares were not mandatorily redeemable, but could 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, 2023, management determined it was probable that the shares would become redeemable at the end of the three-year period and 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, 2024 and 2023, the Company recognized adjustments of years ended December 31, 2024 and 2023, $0.5 million, and $2.5 million, respectively, to the carrying value of the Management Shares to adjust to redemption value.

No Management Shares were redeemed during the years ended December 31, 2024 and 2023.

Employee Stock Purchase Plan — Mezzanine Equity

The Company's Employee Stock Purchase Plan (the "2021 ESPP") was adopted on November 1, 2021 and reserved 3,735,294 shares of common stock for purchase by eligible employees of the Company. As of December 31, 2023, there were 146,116 of the 2021 ESPP shares outstanding. The number of shares available was subject to adjustment based on anti-dilution provisions in the Stockholders' Agreement. The 2021 ESPP allowed for certain eligible non-employees and members of the board of directors to purchase shares under the 2021 ESPP in addition to eligible employees of the Company. There were no shares issued under the 2021 ESPP during the years ended December 31, 2024 and 2023, and during the years ended December 31, 2024 and 2023, the Company redeemed 300 and 100 shares of common stock, respectively. The shares sold under the 2021 ESPP included a put right which allowed for holders of the 2021 ESPP shares to require the Company to purchase the shares upon the occurrence of certain events stipulated by the 2021 ESPP. The shares could also be purchased by the Company, at its discretion upon the occurrence of certain events, as stipulated in the 2021 ESPP. Because the shares were not mandatorily redeemable but could 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 2021 ESPP was recognized within mezzanine equity upon issuance. Management determined it was probable that the shares will become redeemable and 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, 2024 and 2023, the Company recognized an adjustment of an immaterial amount and $0.2 million, respectively, to the carrying value of the 2021 ESPP shares. Upon consummation of the IPO, all 2021 ESPP shares were converted into common stock.

Equity-Based Compensation — Mezzanine Equity

As discussed in *Note 12 - Equity-Based Compensation*, the 2021 Plan included a put right available to the incentive award grant recipients. Accordingly, management determined it was probable the shares issued in settlement of the RSUs upon vesting will become redeemable and elected to carry the shares at redemption value which equals fair market value. During the years ended December 31, 2024 and 2023, the Company recognized an adjustment to the pro-rata portion of the RSUs which have vested in the amounts of $9.3 million and $15.6 million, respectively. The maturities related to the redemption feature were in accordance with the vesting terms discussed in *Note 12 - Equity-Based Compensation*, and took into account the three year and 181 day holding periods. During the years ended December 31, 2024 and 2023, the Company issued 2,696,587 and 133,622 of common stock, respectively, upon vesting of RSUs, net of shares withheld for income taxes. As of December 31, 2023, the Company had 301,134 shares of common stock issued in settlement of vested incentive awards outstanding, which is included in equity-based compensation within mezzanine equity on the consolidated balance sheets of the Company at redemption value of $7.9 million. Upon consummation of the IPO, shares related to equity-based compensation in mezzanine equity were converted into common stock.

Treasury Stock

During the year ended December 31, 2025, the Company did not purchase any shares. During the year ended December 31, 2024, the Company purchased, 150 shares for an immaterial amount at a weighted average price of $26.34 per share, and during the year ended December 31, 2023, the Company purchased 20,748 shares for $0.6 million at a weighted average price of $29.09 per share.

Note 14 - Investments

Equity Method Investment

As of December 31, 2025, the Company was a 50% owner of BKV-BPP Power, which was accounted for as an equity method investment. BKV-BPP Power owns and operates the Temple Plants, which are two combined cycle gas turbine and steam turbine power plants located on the same site in the ERCOT North Zone in Temple, Texas. The Temple Plants deliver power to customers on the ERCOT power network in Texas. BKV-BPP Power also has a wholly-owned subsidiary that engages in retail power sales to customers in Texas.

BKV-BPP Power has a term loan from each of its affiliates, BNAC and BPPUS, each in the amount of $95.5 million, both of which mature on November 1, 2026.

On May 30, 2025, the Company, as lender, entered into a credit facility agreement with BKV-BPP Power to allow BKV-BPP Power to borrow up to $10.0 million from the Company ("BKV-BPP Power Credit Facility"). Interest on the outstanding principal is at six-month SOFR plus an interest rate margin of 5.35%, and payable on a semi-annual basis and upon expiration of the term of the facility. The term of the BKV-BPP Power Credit Facility is from June 1, 2025 until the earlier of May 31, 2027 or until BKV-BPP Power secures a working capital facility from other financial sources. As of December 31, 2025, there were no outstanding borrowings on the BKV-BPP Power Credit Facility.

The Company has an Administrative Service Agreement ("ASA") with BKV-BPP Power, 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, 2025, 2024, and 2023, the Company recognized revenues of $1.8 million, $3.1 million, and $3.6 million, respectively, related to the services provided under the ASA, which is included in related party revenues on the consolidated statements of operations.

During the years ended December 31, 2025, 2024, and 2023, the Company recognized, based on its 50% ownership interest in BKV-BPP Power, earnings of $14.9 million, $10.4 million, and $16.9 million, respectively. For the year ended December 31, 2025, BKV-BPP Power's total revenues, net, included unrealized derivative gains of $7.2 million and operating expenses included unrealized derivative losses of $2.4 million. For the year ended December 31, 2024, BKV-BPP Power's total revenues, net, included unrealized derivative gains of $65.7 million and operating expenses included unrealized derivative losses of $1.7 million. For the year ended December 31, 2023, BKV-BPP Power's total revenues, net, included unrealized derivative losses of $74.2 million and operating expenses included unrealized derivative gains of $0.6 million.

On September 27, 2023, the Power JV Board authorized a dividend to the Company of $10.0 million, and on October 17, 2023, the dividend was paid.

The table below sets forth a reconciliation of BKV Corp's investment in BKV-BPP Power:

(in thousands)		
Balance as of December 31, 2022	$	97,885
Equity in earnings of BKV-BPP Power		16,865
Dividends from Power Joint Venture		(10,000)
Balance as of December 31, 2023		104,750
Equity in earnings of BKV-BPP Power		10,423
Balance as of December 31, 2024		115,173
Equity in earnings of BKV-BPP Power		14,895
Balance as of December 31, 2025	$	130,068

The table below sets forth the summarized financial information of BKV-BPP Power:

Balance Sheet	**December 31,**			
(in thousands)	**2025[(1)]**		**2024[(1)]**	
Current assets	$	123,839	$	140,865
Noncurrent assets		816,142		842,491
Total assets	$	939,981	$	983,356
Current liabilities	$	231,928	$	70,994
Noncurrent liabilities		450,947		685,045
Total liabilities		682,875		756,039
Members' equity		257,106		227,317
Total liabilities and members' equity	$	939,981	$	983,356

(1) Amounts are based on BKV-BPP Power's audited financial statements.

Income Statement	**Year Ended December 31,**					
(in thousands)	**2025[(1)]**		**2024[(1)]**		**2023[(1)]**	
Total revenues, net	$	523,540	$	459,880	$	326,604
Depreciation and amortization		38,273		37,967		31,752
Operating expenses		399,216		331,396		211,323
Income from operations		86,051		90,517		83,529
Interest expense		(63,293)		(72,908)		(50,524)
Other income		7,031		3,476		863
Net income	$	29,789	$	21,085	$	33,868

(1) Amounts are based on BKV-BPP Power's audited financial statements.

On October 29, 2025, the Company entered into the definitive purchase agreement for the BKV-BPP Power Joint Venture Transaction, which closed on January 30, 2026. For additional information, see *Note 19 - Subsequent Events*.

Variable Interest Entities

BKV-CIP Joint Venture

On May 8, 2025, BKV dCarbon Ventures, together with C Squared Solutions, Inc. (the "Class B Member"), a subsidiary of the Energy Transition Fund managed by Copenhagen Infrastructure Partners (CIP), and for the limited purposes specified therein, BKV Corporation, entered into the BKV-CIP JV Agreement forming BKV dCarbon Project, LLC (the "BKV-CIP Joint Venture") for the purpose of developing CCUS projects. On May 8, 2025, BKV dCarbon Ventures contributed to the BKV-CIP Joint Venture $40.3 million of CCUS assets that included the BKV dCarbon Barnett Zero, LLC and BKV dCarbon Las Tiendas, LLC and related assets (including the Barnett Zero and Eagle Ford CCUS projects), and $4.1 million of Section 45Q accrued receivables at carrying value, and committed to future contributions of certain CCUS projects, related assets, and/or cash in exchange for an interest in the BKV-CIP Joint Venture and 4,796,421 Class A Units at $10.00 per share. The Class B Member committed up to an initial $500.0 million in cash for use by the BKV-CIP Joint Venture in construction and operating new CCUS projects across the United States in exchange for no more than a 49% interest in the BKV-CIP Joint Venture. As of December 31, 2025 and during the year ended December 31, 2025, the Class B Member contributed $17.9 million, and received distributions of $1.2 million. In exchange for the Class B Member's contribution to the BKV-CIP Joint Venture, the Class B Member has received a total of 1,791,155 of the BKV-CIP Joint Venture's Class B Units at $10.00 per share.

Net income (loss) is allocated to each member pursuant to the BKV-CIP JV Agreement's liquidation provisions. For the year ended December 31, 2025, BKV dCarbon Ventures and the Class B Member's allocation in BKV-CIP Joint Venture's net income (loss) was 53% and 47%, respectively.

BKV-BPP Cotton Cove Joint Venture

On June 26, 2025, BKV dCarbon Ventures and BPPUS amended and restated the BKV-BPP Cotton Cove LLC Agreement, whereby on July 9, 2025, BKV dCarbon Ventures contributed $3.3 million to BKV-BPP Cotton Cove, net of $0.1 million of expenditures paid by BKV dCarbon Ventures on behalf of BKV-BPP Cotton Cove, and on July 10, 2025, BPPUS received $5.4 million of its initial capital contribution of $8.6 million from BKV-BPP Cotton Cove. Subsequent to these transactions, BKV dCarbon Ventures contributed an additional $5.8 million, for a total of $9.0 million, and BPPUS contributed an additional $5.5 million, for a total of $8.8 million, for the year ended December 31, 2025.

As of December 31, 2025, BKV dCarbon Ventures owns a 51% controlling interest in BKV-BPP Cotton Cove, with BPPUS retaining a 49% interest. The identifiable assets acquired and liabilities assumed were recorded at their estimated fair values as of the acquisition date, with the excess of the fair value of the net assets acquired over the consideration transferred recognized as noncontrolling interest within equity. On July 10, 2025, once the appropriate contributions were made to satisfy the BKV-BPP Cotton Cove LLC Agreement, the primary components of the assets acquired and liabilities assumed included the following (in thousands):

Consideration		
Cash	$	6,927
Total consideration		6,927
Assets acquired and liabilities assumed		
Cash and cash equivalents	$	2,077
Account receivable, net		(624)
Other property and equipment, net		5,535
Accounts payable and accrued liabilities		(61)
Total net assets acquired	$	6,927

Both the BKV-CIP Joint Venture and BKV-BPP Cotton Cove Joint Venture were formed to advance the Company's CCUS strategy and do not represent a material business combination under ASC 805, *Business Combination*, as the assets acquired and liabilities assumed were not significant to the Company's consolidated financial statements. Accordingly, the Company did not recognize goodwill or a bargain purchase gain.

The Company considers the BKV-CIP Joint Venture and BKV-BPP Cotton Cove Joint Venture to each be a VIE in accordance with ASC 810, *Consolidation* as the Company is deemed to be the primary beneficiary of these joint ventures.

Generally, a VIE is an entity with at least one of the following conditions: (i) the total equity investment at risk is insufficient to allow the entity to finance its activities without additional subordinated financial support, or (ii) the holders of the equity investment at risk, as a group, lack the characteristics of having a controlling financial interest. The primary beneficiary of a VIE is an entity that has a variable interest or a combination of variable interests that provide such entity with a controlling financial interest in the VIE. An entity is deemed to have a controlling financial interest in a VIE if it has both of the following characteristics: (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and (ii) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The BKV-CIP Joint Venture and BKV-BPP Cotton Cove are exposed to similar operational risks as the Company, and are each therefore monitored and evaluated on a similar basis by management. The carrying amounts and classification of the consolidated VIE assets and liabilities included in the consolidated balance sheets are as follows (excluding intercompany balances):

(in thousands)	**December 31, 2025**
Assets	
Current assets	
Cash and cash equivalents	$ 5,075
Accounts receivable, net	12,317
Prepaid expenses	23
Other current assets	631
Total current assets	18,046
Other property and equipment, net	72,058
Total assets	$ 90,104
Liabilities	
Current liabilities	
Accounts payable and accrued liabilities	$ 7,149
Total liabilities	$ 7,149

Noncontrolling Interests

Noncontrolling interests held by the Class B Member of 49% in the BKV-CIP Joint Venture and by BPPUS of 49% in BKV-BPP Cotton Cove are presented as noncontrolling interest on the consolidated balance sheets. Pursuant to the BKV-CIP JV Agreement, the Class B Units are not mandatorily redeemable or currently redeemable, but become exercisable with the passage of time, which is on the second anniversary of the BKV-CIP JV Agreement, or May 8, 2027. The Company determined that there is an embedded put option in the Class B Units, which does not meet the derivative accounting criteria, and is not within control of the Company. Therefore, the shares of the BKV-CIP Joint Venture's Class B Units have been classified as noncontrolling interest within mezzanine equity on the Company's consolidated balance sheets. The redemption value of the Class B Units is based on a multiple on invested capital equal to 1.65, which may be redeemed on the second anniversary date. The contributions from the Class B Member are accreted to the redemption value over a 2-year period (using the effective interest method) with the accretion accounted for as a dividend paid to the Class B Member.

As of December 31, 2025, distributions payable to Class B Member was $6.9 million, which represents 49% of the Section 45Q tax credits generated by BKV dCarbon Ventures in 2024. The distributions payable is included in accounts payable and accrued liabilities on the consolidated balance sheets.

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").

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.

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, on occasion, 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 the substantial majority of its 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. As of December 31, 2025 and 2024, the Company's receivables from contracts with customers were $76.8 million and $45.8 million, respectively. Also, as of December 31, 2025 and 2024, one purchaser accounted for more than 10% of accounts receivables, and for the years ended December 31, 2025, 2024, and 2023, the same purchaser's revenues were $675.9 million, $380.6 million, and $476.5 million, respectively. Another purchaser's revenues, that also accounted for more than 10% of the Company's revenues for the years ended December 31, 2025, 2024, and 2023, amounted to $147.6 million, $146.0 million, and $170.6 million, respectively. The Company does not believe that the loss of these customers would have a material adverse effect on the consolidated financial statements because alternative customers are readily available.

Note 16 - Commitments and Contingencies

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, results may change in future periods. 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 recorded a contingent liability of $5.3 million that was carried over from the NEPA acquisition for remitting lease related payments to certain leaseholders. During the year ended December 31, 2024, a judgment was issued in court ruling that BKV was not responsible for this liability and the likelihood of the case being taken up to the supreme court would be minimal. As such, the liability was removed and is reflected in other income on the consolidated statements of operations. In 2021, the Company also recorded an additional $0.4 million of contingent liabilities that was remediated during the year ended December 31, 2024, and is reflected as a reduction in general and administrative expenses on the consolidated statements of operations.

As a part of the consideration paid for the Devon Barnett Acquisition, additional cash consideration would be required to be paid by the Company if certain thresholds were 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 (the "Devon Barnett Earnout"). Average Henry Hub payouts and threshold were 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, $60.00/Bbl $15.0 million, and $65.00/Bbl $20.0 million. Payments were due in the month following the end of the respective measurement period for which the hurdle rates were set. On January 13, 2023, the Company paid the 2022 portion of the arrangement of $65.0 million. On January 12, 2024, the Company paid the 2023 contingent consideration of $20.0 million, and on January 8, 2025, the Company paid the final 2024 contingent consideration of $20.0 million, which is reflected as contingent consideration payable within current liabilities on the consolidated balance sheets. As described in Note 6 - Fair Value Measurements and Note 7 - Derivative Instruments, the contingent consideration was accounted for as a derivative instrument. 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. For the years ended December 31, 2024 and 2023, the changes in the fair value of the contingent consideration were gains of $7.5 million, and $25.0 million, respectively. These changes in the fair value during these periods impacted the associated liability on the consolidated balance sheets and the changes were recognized in the gains on contingent consideration liabilities on the consolidated statements of operations.

In conjunction with the Exxon Barnett Acquisition, additional cash consideration would have been required to be paid by the Company if certain thresholds for future Henry Hub natural gas prices were met for the years ended December 31, 2024 and 2023. Based on the thresholds for these periods, no payouts were required. As of December 31, 2024, the fair value of the contingent consideration was zero. For the years ended December 31, 2024 and 2023, the changes in the fair value of the contingent consideration were gains of $2.2 million, and $13.4 million, respectively. These changes in the fair value during these periods reduced the associated liability on the consolidated balance sheets and the changes were recognized in the gains on contingent consideration liabilities on the consolidated statements of operations. Refer to *Note 6 - Fair Value Measurements* for the valuation methodology and associated inputs.

The Company has commitments in the form of gathering, processing, and transportation agreements with various third parties that require delivery of 892,628,886 dekatherms of natural gas. The significant majority of the agreements terminate by 2029, with one agreement extending through 2036. As of December 31, 2025, the aggregate undiscounted future payments required under these contracts total $259.4 million.

A summary of the Company's commitments, excluding contingent consideration, as of December 31, 2025, is provided in the following table:

(in thousands)	2026	2027	2028	2029	2030	Thereafter	Total
RBL Credit Agreement	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Interest payable	10,104	—	—	—	—	—	10,104
Operating lease payments	6,216	1,139	924	947	978	2,684	12,888
Natural gas transportation commitments	70,249	62,062	53,909	34,257	5,913	33,016	259,406
Total	$ 86,569	$ 63,201	$ 54,833	$ 35,204	$ 6,891	$ 35,700	$ 282,398

Note 17 - Income Taxes

The Company's income (loss) before income taxes has been incurred in the United States. The Company’s income tax expense (benefit) consisted of the following:

Tax Expense (Benefit)

	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Current tax expense (benefit)			
United States federal income tax	$ (476)	$ 573	$ —
Various state income taxes	(528)	633	(4,169)
Total current income tax expense (benefit)	(1,004)	1,206	(4,169)
Deferred tax expense (benefit)			
United States federal income tax	36,598	(44,463)	29,569
Various state taxes	(163)	(348)	2,825
Total deferred income tax expense (benefit)	36,435	(44,811)	32,394
Income tax expense (benefit)	$ 35,431	$ (43,605)	$ 28,225

In 2025, the Company adopted ASU 2023-09, *Income Taxes: Improvement to Income Tax Disclosures* (see *Note 2 - Summary of Significant Accounting Policies*). The following table reconciles the provision for income taxes using the federal statutory rate to the Company's effective tax rate pursuant to the disclosure requirements of ASU 2023-09 for the years ended December 31, 2025, 2024, and 2023. Income tax expense (benefit) attributable to pre-tax income differed from the amounts computed by applying the U.S. federal statutory income tax rate of 21% to pre-tax income by the following:

	Year Ended December 31,					
($ in thousands)	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Income (loss) before income taxes	$ 210,275		$ (186,475)		$ 145,143	
U.S. federal tax at statutory tax rate	$ 44,158	21.0 %	$ (39,160)	21.0 %	$ 30,480	21.0 %
State and local income taxes, net of federal income tax effect	(692)	(0.3)%	(76)	— %	(1,344)	(0.9)%
Tax credits						
Investment tax credit	—	— %	(1,010)	0.5 %	—	— %
Marginal well credit	(10,226)	(4.9)%	(7,644)	4.1 %	—	— %
Nontaxable or nondeductible items						
Section 162(m) limitation	1,756	0.8 %	8,881	(4.8)%	—	— %
Excess tax benefits from vesting of restricted shares	(167)	(0.1)%	(3,829)	2.1 %	(373)	(0.3)%
Section 45Q tax credits	(855)	(0.4)%	(2,944)	1.6 %	(147)	(0.1)%
Other, net	1,391	0.7 %	67	— %	89	0.1 %
Other adjustments	66	— %	2,110	(1.1)%	(480)	(0.3)%
Income tax expense (benefit)	$ 35,431	16.8 %	$ (43,605)	23.4 %	$ 28,225	19.4 %

State taxes in Texas and Pennsylvania made up the majority of the tax effect in the state and local income taxes category. Income taxes paid (net of refunds) consisted of the following for the years ended December 31, 2025, 2024, and 2023:

	Year Ended December 31,		
(in thousands)	2025	2024	2023
Federal	$ —	$ —	$ —
State	232	6	1,545
Total taxes paid (net of refunds)	$ 232	$ 6	$ 1,545

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)	December 31, 2025	December 31, 2024
Deferred tax assets		
Fair value of derivative financial instruments	$ —	$ 9,018
Asset retirement obligations	51,528	46,240
Equity-based compensation	1,649	494
Contingent consideration	353	4,597
Interest expense carryforward	34,837	33,029
Net operating loss carryforward	67,692	35,826
Accrued bonuses	5,226	4,218
Marginal well credit	23,669	13,180
Other	4,441	7,373
Total deferred tax asset	189,395	153,975
Deferred tax liabilities		
Property and equipment	(243,355)	(193,977)
Investment in joint venture	(50,766)	(46,226)
Fair value of derivative financial instruments	(15,240)	—
Other	(3,389)	(2,460)
Total deferred tax liability	(312,750)	(242,663)
Deferred tax liability, net	$ (123,355)	$ (88,688)

As of December 31, 2025, the Company has an NOL carryforward deferred tax asset for federal tax purposes of $66.3 million, which does not expire and a NOL carryforward deferred tax asset for state tax purposes of $1.3 million, which expires between 2043 and 2045. In addition, as of December 31, 2025, the Company has a Section 163(j) interest expense carryforward deferred tax asset of $34.8 million, which does not expire, marginal well credits of $23.7 million that expire between 2040 and 2045, and investment tax credits of $1.0 million that expire in 2044. Section 382 of the Code limits the use of NOL carryforwards, 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 were to experience an ownership change of more than 50% of the value of its capital stock, utilization of its NOL, interest expense, and tax credit carryforwards could be subject to limitation. As of December 31, 2025, management does not believe that the Company has experienced an ownership change, and therefore, does not believe that its NOL, Section 163(j) interest expense, and tax credit carryforwards are currently subject to limitation under Section 382.

Due to the proportional change in BNAC's beneficial ownership of the Company following the IPO, the Company was deconsolidated from BNAC for federal income tax purposes. In accordance with the Code and related regulations, the Company allocated the cumulative NOL carryforwards, Section 163(j) interest expense carryforwards, and other general business tax credits between BNAC and the Company. These allocations impacted the Company's deferred tax liability, net balance by increasing the NOL carryforward by $1.8 million and $14.3 million as of December 31, 2025 and 2024, respectively, and increasing general business tax credits by $2.5 million, while reducing the Section 163(j) interest expense carryforward by $6.3 million as of December 31, 2024. The net impact was recorded as an adjustment to additional paid-in capital, as reflected in the table above.

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 and liabilities, projected future taxable income, and tax planning strategies in making this assessment. Accordingly, as of December 31, 2025 and 2024, 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 had no unrecognized tax benefits during the years ended December 31, 2025, 2024, and 2023 and had no unrecognized tax benefit balances as of December 31, 2025 and 2024. The Company is generally subject to potential federal and state examination for the tax years on and after December 31, 2022. For Texas, the Company is subject to examination for the tax years on and after December 31, 2021.

Note 18 - Earnings Per Share

Basic net income (loss) per common share attributable to BKV for each period is calculated by dividing net income (loss) attributable to BKV by the basic weighted average number of common shares outstanding during the period. Diluted net income (loss) per common share attributable to BKV is calculated by dividing net income (loss) attributable to BKV by the diluted weighted average number of common shares outstanding for the respective period. Any remeasurement of the accretion to redemption value of the Class B Units subject to possible redemption was considered to be dividends paid to the noncontrolling interest. Diluted weighted average number of common shares outstanding and the dilutive effect of potential common shares is calculated using the treasury method. The Company includes potential shares of common stock for PRSUs and TRSUs 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.

The following is the calculation of basic and diluted net income (loss) per common share attributable to BKV for the years ended December 31, 2025, 2024, and 2023:

	Year Ended December 31,		
(in thousands, except per share amounts)	**2025**	**2024**	**2023**
Net income (loss) attributable to BKV	$ 173,132	$ (142,870)	$ 116,918
Accretion of Class B Units to redemption value	(1,422)	—	—
Net income (loss) including accretion of Class B Units to redemption value	$ 171,710	$ (142,870)	$ 116,918
Basic weighted average common shares outstanding	86,581	71,288	60,730
Add: dilutive effect of TRSUs	173	—	172
Add: dilutive effect of PRSUs	69	—	3,478
Diluted weighted average of common shares outstanding	86,823	71,288	64,380
Weighted average number of outstanding securities excluded from the calculated of diluted loss per share:			
TRSUs	—	264	—
PRSUs	—	2,523	—
Net income (loss) per common share attributable to BKV:			
Basic	$ 1.98	$ (2.00)	$ 1.93
Diluted	$ 1.98	$ (2.00)	$ 1.82

Note 19 - Subsequent Events

On January 14, 2026, the Company entered into a manufacturing reservation agreement related to a planned power generation project. Under the agreement, the Company is committed to pay up to an aggregate of $80.0 million in reservation fees, scheduled in phases during 2026, to secure future manufacturing capacity through 2028 for turbines with up to approximately 1,230 megawatts in total generation capacity. Amounts paid are generally non-refundable and will be credited against the purchase price if a definitive supply agreement is executed.

On January 30, 2026, the Company completed the previously announced acquisition of an additional 25% interest in the BKV-BPP Power Joint Venture for aggregate consideration of $115.1 million in cash and 5,315,390 shares of Company common stock, which shares are subject to a 180-day lock-up. The aggregate purchase price was equal to (x) $376.0 million, less (y) 25% of BKV-BPP Power's net indebtedness at the closing, payable 50% in cash and 50% in shares of the Company's common stock. BKV-BPP Power's net indebtedness was $582.9 million as of the closing date and the number of shares issued was determined by dividing the 50% of the aggregate purchase price by $21.6609, which represents the volume-weighted average price of the Company's common stock during the 20 consecutive trading day period ended October 28, 2025. The Company funded the cash consideration for the transaction with a combination of cash on hand and the net proceeds from the underwritten public equity offering of 6,900,000 shares of Company common stock completed on December 3, 2025. Following the closing of the transaction, the Company and BPPUS own 75% and 25% of the BKV-BPP Power Joint Venture, respectively, and the Company will consolidate the financial results of BKV-BPP Power into the Company's consolidated financial results.

Also on January 30, 2026, the Company amended and restated its ASA with BKV-BPP Power LLC, effective January 1, 2026, to provide continued and updated administrative services and support to BKV-BPP Power. The amended and restated ASA has an initial term through December 31, 2026, and renews annually on January 1 for additional one-year terms unless mutually terminated. Fees under the ASA are reviewed and updated annually and are assessed based on services provided.

As of December 31, 2025 and through March 6, 2026, which represents the date these consolidated financials are available to be issued, the Company evaluated these events in accordance with ASC 855, *Subsequent Events*, and determined they represent nonrecognized subsequent events. No other subsequent events have occurred that would require recognition or disclosure to the consolidated financial statements and the notes thereto.

Note 20 - 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:

	December 31,	
(in thousands)	**2025**	**2024**
Developed properties	$ 2,965,638	$ 2,315,167
Undeveloped properties	13,182	10,757
Total capitalized costs	2,978,820	2,325,924
Less: accumulated depreciation, depletion, and amortization	(825,694)	(697,002)
Net capitalized costs	$ 2,153,126	$ 1,628,922

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:

	For the Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Undeveloped property acquisition costs	$ 2,425	$ 775	$ 335
Acquisitions [(1)]	392,626	—	9,885
Development costs	259,364	95,427	107,544
Total cost incurred	654,415	96,202	117,764
Asset retirement obligations	226	42	89
Total costs incurred including asset retirement obligations	$ 654,641	$ 96,244	$ 117,853

[(1)] For the year ended December 31, 2025, acquisition costs include the natural gas properties acquired in the Bedrock Acquisition, and for the year ended December 31, 2023, acquisition costs include the mineral interests in acquired wells and additional costs related to previous acquisitions.

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, 2025, 2024, and 2023 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, reserve estimates are subject to periodic revision. 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, 2023	4,855,676	211,500	1,869	6,135,890
Revision of previous estimates	(1,828,619)	(25,570)	(704)	(1,986,263)
Extensions and discoveries	188,572	6,539	—	227,806
Improved recoveries	16,632	2,250	5	30,162
Production	(249,766)	(10,554)	(119)	(313,804)
December 31, 2023	2,982,495	184,165	1,051	4,093,791
Revision of previous estimates	(485,190)	(35,891)	(2,401)	(714,942)
Extensions and discoveries	79,148	9,197	813	139,208
Improved recoveries	38,224	10	2,324	52,228
Net sales of minerals in place	(149,963)	—	—	(149,963)
Production	(228,683)	(9,859)	(96)	(288,413)
December 31, 2024	2,236,031	147,622	1,691	3,131,909
Revision of previous estimates	1,753,200	73,155	1,472	2,200,960
Extensions and discoveries	118,208	1,891	—	129,554
Improved recoveries	18,109	407	1	20,560
Purchases of minerals in place	463,147	45,762	876	742,978
Production	(242,931)	(10,181)	(159)	(304,975)
December 31, 2025	4,345,764	258,656	3,881	5,920,986
Proved developed reserves as of:				
January 1, 2023	2,443,072	156,399	992	3,387,418
December 31, 2024	2,059,983	134,016	878	2,869,347
December 31, 2025	3,097,864	183,111	1,763	4,207,108
Proved undeveloped reserves as of:				
January 1, 2023	539,423	27,766	59	706,373
December 31, 2024	176,048	13,606	813	262,562
December 31, 2025	1,247,900	75,545	2,118	1,713,878

(in MMcfe)	Developed	Undeveloped	Total
January 1, 2023	4,829,733	1,306,157	6,135,890
Revision of previous estimates	(1,191,886)	(794,377)	(1,986,263)
Extensions and discoveries	1,289	226,517	227,806
Improved recoveries	30,162	—	30,162
Production	(313,804)	—	(313,804)
Undeveloped reserves converted to developed	31,924	(31,924)	—
December 31, 2023	3,387,418	706,373	4,093,791
Revision of previous estimates	(235,580)	(479,362)	(714,942)
Extensions and discoveries	—	139,208	139,208
Improved recoveries	52,228	—	52,228
Net sales of minerals in place	(103,887)	(46,076)	(149,963)
Production	(288,413)	—	(288,413)
Undeveloped reserves converted to developed	57,581	(57,581)	—
December 31, 2024	2,869,347	262,562	3,131,909
Revision of previous estimates	915,783	1,285,177	2,200,960
Extensions and discoveries	—	129,554	129,554
Improved recoveries	20,560	—	20,560
Purchases of minerals in place	494,590	248,388	742,978
Production	(304,975)	—	(304,975)
Undeveloped reserves converted to developed	211,803	(211,803)	—
December 31, 2025	4,207,108	1,713,878	5,920,986

2025 Activity

During the year ended December 31, 2025, the Company’s proved reserves increased by 2,789.1 Bcfe. The increase in proved reserves was primarily attributable to increased commodity pricing and drilling activity, which resulted in total upward revisions of 2,201.0 Bcfe. In addition, in September 2025, BKV Upstream Midstream acquired 100% of the equity interests of BKV Barnett II (formerly known as Bedrock Production, LLC), increasing reserves by 743.0 Bcfe. Extensions and discoveries and improved recoveries experienced by the Company in 2025 also resulted in net increases to proved reserves of 129.6 Bcfe and 20.6 Bcfe, respectively. The Company produced 305.0 Bcfe during the year ended December 31, 2025.

Revisions of previous estimates — Primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 915.8 Bcfe and 679.2 Bcfe, respectively, as a result of higher average pricing during 2025 for natural gas, NGLs, and oil. Additional upward revisions were made to proved undeveloped reserves of 599.2 Bcfe due to increases in capital spend and drilling activity during 2025. Changes to the Company’s drilling schedule added 86.0 gross (81.2 net) proved locations in NEPA and the Barnett to be developed within the next five years. The drilling schedule changes reflect the Company’s ongoing commitment to optimize the long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries — Added 129.6 Bcfe of proved undeveloped reserves across 11.0 gross (8.9 net) locations driven by the Company's optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2025.

Improved recoveries — Added 20.6 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2025.

Purchases of minerals in place — Consisted of 494.6 Bcfe and 248.4 Bcfe of acquired proved developed reserves and proved undeveloped reserves, respectively, from the Bedrock Acquisition, which represented 1,002.0 gross (877.6 net) locations in the Barnett.

Conversions of proved undeveloped reserves to proved developed reserves — Consisted of 211.8 Bcfe related to the completion of 34.0 gross (31.0 net) wells during the year ended December 31, 2025 that were converted to proved developed wells, previously classified as proved undeveloped. Development costs relating to the development of the Company's proved undeveloped reserves were $1.0 billion for the year ended December 31, 2025.

2024 Activity

During the year ended December 31, 2024, the Company's proved reserves decreased by 961.9 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in the Company's planned drilling activity, which resulted in total downward revisions of 714.9 Bcfe. In addition, in June 2024, the Company sold its wholly-owned subsidiary, Chaffee, and certain of its non-operated upstream assets in Chelsea, decreasing reserves by 150.0 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries experienced by the Company in 2024, which resulted in net increases to proved reserves of 139.2 Bcfe and 52.2 Bcfe, respectively. The Company produced 288.4 Bcfe during the year ended December 31, 2024.

Revisions of previous estimates — Primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 235.6 Bcfe and 213.7 Bcfe, respectively, as a result of lower average pricing during 2024 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 265.6 Bcfe due to lower capital spend and the resulting reduction in drilling activity during 2024. Changes to the Company's drilling schedule moved the development of 38.0 gross (35.1 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUD reserves five years from initial booking. These 38.0 gross (35.1 net) locations remain in inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect the Company's ongoing commitment to optimize the long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries — Primarily consisted of 139.2 Bcfe of proved undeveloped reserves across 16.0 gross (14.4 net) locations, driven by the Company's optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2024.

Improved recoveries — Consisted of 52.2 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2024.

Sales of minerals in place — Consisted of 103.9 Bcfe and 46.1 Bcfe of divested proved developed reserves and proved undeveloped reserves, respectively, of Chaffee assets and certain non-operated upstream assets in Chelsea, both sold in June 2024, which represented 330.0 gross (39.6 net) locations in NEPA.

Conversions of proved undeveloped reserves to proved developed reserves — Consisted of 57.6 Bcfe related to the completion of 8.0 gross (7.9 net) wells during the year ended December 31, 2024 that were converted to proved developed wells, previously classified as proved undeveloped.

2023 Activity

During the year ended December 31, 2023, the Company's proved reserves decreased by 2,042.1 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in the Company's drilling activity, which resulted in total downward revisions of 1,986.3 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries in 2023, which resulted in net increases to proved reserves of 227.8 Bcfe and 30.2 Bcfe, respectively. The Company produced 313.8 Bcfe during the year ended December 31, 2023.

Revisions of previous estimates — Consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 1,191.9 Bcfe and 273.1 Bcfe, respectively, as a result of lower average pricing during 2023 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 521.3 Bcfe due to lower capital spend and the resulting reduction in drilling activity during 2023. Changes to the Company's drilling schedule moved the development of 112.0 gross (104.8 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUD reserves five years from initial booking. These 112.0 gross (104.8 net) locations remain in inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect the Company's ongoing commitment to optimize its long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries — Primarily consisted of 226.5 Bcfe of proved undeveloped reserves, of which 197.8 Bcfe was attributable to 22.0 gross (21.2 net) locations recognized as a result of the Company's optimized drilling program, which reduced costs and extended lateral lengths. In addition, 28.7 Bcfe was attributable to extensions related to 3.0 gross (1.1 net) locations in NEPA. The Company's unitization and combination of acreage with Repsol resulted in the three additional locations.

Improved recoveries — Consisted of 30.2 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, 2023.

Conversions of proved undeveloped reserves to proved developed reserves — Consisted of 31.9 Bcfe related to the completion of 22.0 gross (8.1 net) wells during the year ended December 31, 2023 that were converted to proved developed wells, previously classified as proved undeveloped.

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	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Future cash inflows	$ 16,928,259	$ 6,207,197	$ 9,691,057
Future production costs	(8,616,382)	(4,026,521)	(5,799,209)
Future development costs [1]	(1,657,625)	(666,194)	(977,333)
Future income tax expense	(1,111,793)	(96,180)	(406,937)
Future net cash flows	5,542,459	1,418,302	2,507,578
10% annual discount for estimated timing of cash flows	(3,197,795)	(785,216)	(1,445,245)
Standardized measure of discounted future net cash flows related to proved reserves	$ 2,344,664	$ 633,086	$ 1,062,333

[1] Includes abandonment costs.

The following table summarizes the changes in the Standardized Measure:

	Year Ended December 31,		
(in thousands)	**2025**	**2024**	**2023**
Balance, beginning of period	$ 633,086	$ 1,062,333	$ 6,993,602
Net change in sales and transfer prices and in production (lifting) costs related to future production	943,628	(272,270)	(5,386,961)
Changes in estimated future development costs	(37,067)	(2,933)	91,657
Sales and transfers of natural gas, NGLs, and oil produced during the period	(381,138)	(271,692)	(201,884)
Net change due to extensions, discoveries, and improved recoveries	75,400	18,261	36,107
Net change due to purchases (sales) of minerals in place	337,761	(90,531)	—
Net change due to revisions in quantity estimates	1,007,937	(74,031)	(3,058,900)
Previously estimated development costs incurred during the period	21,467	24,291	27,598
Net change in future income taxes	(404,531)	131,401	1,790,684
Accretion of discount	67,190	123,255	861,914
Changes in timing and other	80,931	(14,998)	(91,484)
Total discounted cash flow as end of period	$ 2,344,664	$ 633,086	$ 1,062,333

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rules 13a-15(b) and 15d-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective at a reasonable assurance level as of December 31, 2025.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2025.

This Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting as we qualify as an "emerging growth company" as of December 31, 2025.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Securities Trading Plans of Directors and Executive Officers

On November 11, 2025, Mr. Eric Jacobsen, President — Upstream and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408 (a "Rule 10b5-1 Trading Plan"). Mr. Jacobsen's Rule 10b5-1 Trading Plan, which has a plan end date of November 11, 2026, provides for the sale of up to 50,000 shares of common stock pursuant to the terms of the plan.

On December 2, 2025, Mr. Chris Kalnin, Chief Executive Officer and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, terminated his Rule 10b5-1 Trading Plan, which was previously adopted on March 14, 2025, and had a plan end date of March 14, 2026. Mr. Kalnin's terminated Rule 10b5-1 Trading Plan provided for the sale of up to 400,000 shares of common stock pursuant to the terms of the plan of which, as of the termination date, 300,000 shares of common stock had been sold.

Subsequently, on December 8, 2025, Mr. Kalnin adopted a new 10b5-1 Trading Plan, which has a plan end date of December 1, 2026, and provides for the sale of up to 100,000 shares of common stock pursuant to the terms of the plan.

On December 3, 2025, Mr. David Tameron, Chief Financial Officer and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan. Mr. Tameron's Rule 10b5-1 Trading Plan, which has a plan end date of June 3, 2026, provides for the sale of up to 7,300 shares of common stock pursuant to the terms of the plan.

On December 15, 2025, Mr. Ethan Ngo, Chief Corporate Development Officer and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan. Mr. Ngo's Rule 10b5-1 Trading Plan, which has a plan end date of November 30, 2026, provides for the sale of up to 75,000 shares of common stock pursuant to the terms of the plan.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTION THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The names of our executive officers and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by BKV pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than 120 days after the close of our fiscal year ended December 31, 2025 (the "2026 Proxy Statement").

BKV has adopted an insider trading policy and procedures governing the purchase, sale and other disposition of BKV's securities by directors, officers and employees that is reasonably designed to promote compliance with insider trading laws, rules and regulations and applicable NYSE listing standards. A copy of BKV's insider trading policy is filed as an exhibit to this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the 2026 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNER AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information called for by this Item 12 is incorporated herein by reference to the 2026 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information called for by this Item 13 is incorporated herein by reference to the 2026 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information called for by this Item 14 is incorporated herein by reference to the 2026 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements*. BKV's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.

2. *Financial Statement Schedules*. No financial statement schedules are applicable or required.

3. *Exhibits*. The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

		Incorporated by Reference				
Exhibit Number	**Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed or Furnished Herewith**
2.1+‡	Purchase and Sale Agreement, dated December 17, 2019, between Devon Energy Production Company, L.P. and BKV Barnett, LLC.	S-1	333-268469	2.1	8/12/2022	
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.	S-1	333-268469	2.2	8/12/2022	
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.	S-1	333-268469	2.3	8/12/2022	
2.4+‡	Membership Interest Purchase Agreement, dated as of August 7, 2025, by and among BKV Upstream Midstream, LLC, Bedrock Energy Partners, LLC, certain of its subsidiaries and, solely for certain limited purposes set forth herein, BKV Corporation.	10-Q	001-42282	2.1	11/10/2025	
2.5+	Membership Interest Purchase Agreement, dated as of October 29, 2025, by and between BKV Corporation and Banpu Power US Corporation.	10-Q	001-42282	2.2	11/10/2025	
3.1	Second Amended and Restated Certificate of Incorporation of BKV Corporation.	8-K	001-42282	3.1	9/27/2024	
3.2	Second Amended and Restated Bylaws of BKV Corporation.	8-K	001-42282	3.2	9/27/2024	
4.1	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.					X
4.2	Indenture, dated as of September 26, 2025, by and among BKV Upstream Midstream, LLC, the guarantors party thereto and U.S. Bank Trust Company, National Association, as trustee (including Form of Note).	8-K	001-42282	4.1	10/1/2025	
4.3	First Supplemental Indenture, dated as of September 29, 2025, by and among BKV Upstream Midstream, LLC, Bedrock Production, LLC, Bedrock Development Partners, LLC, Bedrock ABS I Holdings, LLC, Bedrock ABS I, LLC and U.S. Bank Trust Company, National Association, as trustee.	8-K	001-42282	4.2	10/1/2025	
10.1†	Employment Agreement, dated August 4, 2020, between BKV Corporation and Christopher P. Kalnin.	S-1	333-268469	10.16	8/12/2022	
10.2†	Employment Agreement, dated February 18, 2020, between Kalnin Ventures LLC and Eric Jacobsen.	S-1	333-268469	10.18	8/12/2022	
10.3†	Employment Agreement, dated October 15, 2018, between Kalnin Ventures LLC and Lindsay B. Larrick.	S-1	333-268469	10.2	8/12/2022	

10.4†	Employment Agreement, dated April 1, 2018, between Kalnin Ventures LLC and An Sao (Ethan) Ngo.	S-1	333-268469	10.21	8/12/2022
10.5†	Limited Liability Company Agreement of BKV-BPP Power LLC dated October 29, 2021.	S-1	333-268469	10.22	8/12/2022
10.6†	BKV Corporation Non-Employee Director Compensation Program.	S-1	333-268469	10.24	9/16/2022
10.7†	Letter Agreement, dated November 14, 2022, between Kalnin Ventures, LLC and Barry Turcotte.	S-1	333-268469	10.31	12/22/2022
10.8†	Employment Agreement, effective October 9, 2023, between BKV Corporation and Mary Rita Valois.	S-1	333-268469	10.42	1/12/2024
10.9	Credit Agreement dated as of June 11, 2024 among BKV Corporation, BKV Upstream Midstream, LLC, Citibank, N.A., and the Lenders party thereto.	S-1	333-268469	10.44	7/5/2024
10.10	Stockholders' Agreement, dated September 27, 2024, by and between BKV Corporation and Banpu North America Corporation.	8-K	001-42282	10.1	9/27/2024
10.11	Amended and Restated Tax Sharing Agreement, dated September 27, 2024, by and between BKV Corporation and Banpu North America Corporation.	8-K	001-42282	10.2	9/27/2024
10.12†	BKV Corporation 2024 Equity and Incentive Compensation Plan (the "2024 Plan").	8-K	001-42282	10.3	9/27/2024
10.13†	Time Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (CEO).	8-K	001-42282	10.4	9/27/2024
10.14†	Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (CEO).	8-K	001-42282	10.5	9/27/2024
10.15†	Time Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Non-CEO Employee).	8-K	001-42282	10.6	9/27/2024
10.16†	Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Non-CEO Employee).	8-K	001-42282	10.7	9/27/2024
10.17†	Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Director).	8-K	001-42282	10.8	9/27/2024
10.18†	Form of Director and Officer Indemnity Agreement.	8-K	001-42282	10.9	9/27/2024
10.19†	Transition and Mutual Separation Agreement, dated as of February 3, 2025, between BKV Corporation and John T. Jimenez.	8-K	001-42282	10.1	2/3/2025
10.20†	Employment Agreement, dated as of February 3, 2025, between BKV Corporation and David R. Tameron.	8-K	001-42282	10.2	2/3/2025
10.21†	Amended and Restated Employment Agreement, dated as of February 3, 2025, between BKV Corporation and Eric S. Jacobsen.	8-K	001-42282	10.3	2/3/2025
10.22	Second Amendment to Credit Agreement, dated as of May 6, 2025 among BKV Corporation, BKV Upstream Midstream, LLC, Citibank, N.A., and the Lenders party thereto.	10-Q	001-42282	10.4	5/9/2025
10.23‡	Limited Liability Company Agreement of BKV dCarbon Project, LLC dated as of May 8, 2025 by BKV dCarbon Ventures, LLC and C Squared Solutions, Inc. and for the limited purposes specified herein, BKV Corporation.	10-Q	001-42282	10.2	8/12/2025

10.24	Third Amendment to Credit Agreement, dated as of September 22, 2025, among BKV Corporation, as guarantor, BKV Upstream Midstream, LLC, as borrower, certain subsidiaries of BKV Upstream Midstream, LLC, as guarantors, Citibank, N.A., as administrative agent, and the lenders party thereto.	8-K	001-42282	10.1	9/22/2025	
10.25	Registration Rights Agreement, dated as of September 29, 2025, by and between BKV Corporation and Bedrock Energy Partners, LLC.	10-Q	001-42282	10.2	11/10/2025	
10.26+	Fourth Amendment to Credit Agreement, dated as of October 27, 2025, among BKV Corporation, as guarantor, BKV Upstream Midstream, LLC, as borrower, certain subsidiaries of BKV Upstream Midstream, LLC, as guarantors, Citibank, N.A., as administrative agent, and the lenders party thereto.	10-Q	001-42282	10.3	11/10/2025	
10.27	Registration Rights Agreement, dated as of January 30, 2026, by and between BKV Corporation and Banpu Power US Corporation.	8-K	001-42282	10.1	1/30/2026	
10.28+	Amended and Restated Limited Liability Company Agreement of BKV-BPP Power LLC, dated as of January 30, 2026.	8-K	001-42282	10.2	1/30/2026	
10.29†	Amended and Restated BKV Corporation 2024 Equity and Incentive Compensation Plan.					X
10.30†	Employment Agreement, dated as of April 3, 2025, between BKV Corporation and Dilanka Seimon.					X
19.1	Insider Trading Policies and Procedures.	10-K	001-42282	19.1	3/31/2025	
21.1	List of Subsidiaries of BKV Corporation.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Ryder Scott Company, L.P.					X
31.1	Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
97.1	Clawback Policy of BKV Corporation.	10-K	001-42282	97.1	3/31/2025	
99.1	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2025 (SEC Pricing) (Total Company Assets).					X
99.2	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2025 (NYMEX Pricing) (Total Company Assets).					X
101.INS	Inline XBRL Instance Document.					X
101.SCH	XBRL Taxonomy Extension Schema Document.					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.					X

101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	X
104	Cover Page Interactive Data File (embedded within the inline XBRL document).	X

+ 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.

† Compensatory plan or arrangement

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BKV CORPORATION

Date: March 6, 2026

By: /s/ David R. Tameron
David R. Tameron
Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and 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)	March 6, 2026
/s/ David R. Tameron David R. Tameron	Chief Financial Officer (Principal Financial Officer)	March 6, 2026
/s/ Barry S. Turcotte Barry S. Turcotte	Chief Accounting Officer (Principal Accounting Officer)	March 6, 2026
/s/ Chanin Vongkusolkit Chanin Vongkusolkit	Chairman of the Board	March 6, 2026
/s/ Somruedee Chaimongkol Somruedee Chaimongkol	Director	March 6, 2026
/s/Joseph R. Davis Joseph R. Davis	Director	March 6, 2026
/s/ Akaraphong Dayananda Akaraphong Dayananda	Director	March 6, 2026
/s/ Kirana Limpaphayom Kirana Limpaphayom	Director	March 6, 2026

/s/ Carla S. Mashinski Carla S. Mashinski	Director	March 6, 2026
/s/ Thiti Mekavichai Thiti Mekavichai	Director	March 6, 2026
/s/ Charles C. Miller III Charles C. Miller III	Director	March 6, 2026
/s/ Sunit S. Patel Sunit S. Patel	Director	March 6, 2026
/s/Anon Sirisaengtaksin Anon Sirisaengtaksin	Director	March 6, 2026
/s/ Sinon Vongkusolkit Sinon Vongkusolkit	Director	March 6, 2026

DESCRIPTION OF SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

As of the end of the period covered by the most recent Annual Report on Form 10-K of BKV Corporation ("BKV," "we," "us," "our" or the "Company"), BKV has one class of securities registered under Section 12 of the Securities Exchange Act of 1934 (the "Exchange Act"): its common stock, $0.01 par value per share.

General

Pursuant to our Second Amended and Restated Certificate of Incorporation (the "certificate of incorporation"), our authorized capital stock consists of:

- 500,000,000 shares of common stock, $0.01 par value per share, and
- 80,000,000 shares of preferred stock, $0.01 par value per share.

There is no preferred stock outstanding.

Common Stock

The following description of our common stock is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our certificate of incorporation and our Second Amended and Restated Bylaws (the "bylaws"), each of which are included as exhibits to BKV's most recent Annual Report on Form 10-K and are incorporated by reference herein, and (iii) the applicable provisions of the General Corporation Law of the State of Delaware (the "DGCL"). We encourage you to read our certificate of incorporation, bylaws and the applicable provisions of the DGCL for additional information.

Voting Rights

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 Banpu North America Corporation ("BNAC") under the Stockholders' Agreement we entered into on September 27, 2024 (the "Stockholders' Agreement"), which is filed as an exhibit to BKV's most recent Annual Report on Form 10-K, holders of our common stock are entitled to elect all directors to our board of directors.

Dividend Rights

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.

Liquidation, Dissolution and Winding-Up Rights

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.

Other Rights

All outstanding shares of our common stock are fully paid and non-assessable. Our common stock is not 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 are no redemption or sinking fund provisions applicable to our common stock. The rights powers, preferences and privileges of our common stock are 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

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 are 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.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Broadridge Corporate Issuer Solutions, Inc. The transfer agent and registrar's address is 51 Mercedes Way, Edgewood, New York 11717.

Listing

Shares of our common stock are listed on the NYSE under the symbol "BKV."

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.

Classified Board of Directors

Our certificate of incorporation provides that our board of directors is 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 has 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 are 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 have not elected 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 an appointment made 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.

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, as well as certain requirements regarding the form and content of a shareholder's notice for any such proposal. In order for any matter to be "properly brought" before a meeting, any such proposals will have to comply with these advance notice, form and content requirements.

Stockholder Action by Written Consent

Under the DGCL, any action required to be taken at any annual or special meeting of 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 our 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 any applicable law, 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 any applicable law, 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 of 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 any applicable law, securities exchange rule or regulation)), is 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.

Choice of Forum

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 is 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 of 1933, as amended (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.

In addition, in light of the role of Mr. Christopher P. Kalnin, our Chief Executive Officer, on the Executive Committee of Banpu Public Company Limited, a public company listed on the Stock Exchange of Thailand and the ultimate parent company of BKV and BNAC, our board of directors has adopted a corporate opportunity policy that requires Mr. Kalnin to present applicable business opportunities of which he may become aware to our Company before such opportunities may be presented to Banpu or one of its affiliates.

BKV CORPORATION

2024 EQUITY AND INCENTIVE COMPENSATION PLAN
(amended and restated as of March 5, 2026)

1. **Purpose.** The purpose of this Plan is to permit award grants to non-employee Directors, officers and other employees of the Company and its Subsidiaries, and to provide to such persons incentives and rewards for service and/or performance.

2. **Definitions.** As used in this Plan:

(a) "Appreciation Right" means a right granted pursuant to **Section 5** of this Plan.

(b) "Base Price" means the price, determined by the Committee in its sole discretion, to be used as the basis for determining the Spread upon the exercise of an Appreciation Right.

(c) "Board" means the Board of Directors of the Company.

(d) "Cash Incentive Award" means a cash award granted pursuant to **Section 8** of this Plan.

(e) "Change in Control" has the meaning set forth in **Section 12** of this Plan.

(f) "Code" means the Internal Revenue Code of 1986, as amended from time to time, and the regulations thereunder, as such law and regulations may be amended from time to time.

(g) "Committee" means the Compensation Committee of the Board (or its successor(s)), or any other committee of the Board designated by the Board to administer this Plan pursuant to **Section 10** of this Plan.

(h) "Common Shares" means the shares of common stock, par value $0.01 per share, of the Company or any security into which such common shares may be changed by reason of any transaction or event of the type referred to in **Section 11** or **Section 12** of this Plan.

(i) "Company" means BKV Corporation, a Delaware corporation, and its successors.

(j) "Company Voting Securities" means the voting securities of the Company entitled to vote generally in the election of Directors.

(k) "Date of Grant" means the date provided for by the Committee on which a grant of Option Rights, Appreciation Rights, Performance Shares, Performance Units, Cash Incentive Awards, or other awards contemplated by **Section 9** of this Plan, or a grant or sale of Restricted Shares, Restricted Stock Units, or other awards contemplated by **Section 9** of this Plan, will become effective (which date will not be earlier than the date on which the Committee takes action with respect thereto).

(l) "Director" means a member of the Board.

(m) "Effective Date" has the meaning set forth in **Section 20** of this Plan.

(n) "Evidence of Award" means an agreement, certificate, resolution or other type or form of writing or other evidence approved by the Committee that sets forth the terms and conditions of the awards granted under this Plan. An Evidence of Award may be in an electronic medium, may be limited to notation on the books and records of the Company and, unless otherwise determined by the Committee, need not be signed by a representative of the Company or a Participant.

(o) "Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time, and the rules and regulations thereunder, as such law, rules and regulations may be amended from time to time.

(p) "Exempt Person" means each of Banpu Public Company Limited, a public company incorporated in and existing under the Laws of Thailand, and any corporation, company or other entity that is wholly-owned by Banpu Public Company Limited, as of the relevant time.

(q) "Management Objectives" means the measurable performance objective or objectives established pursuant to this Plan for Participants who have received grants of Performance Shares, Performance Units or Cash Incentive Awards or, when so determined by the Committee, Option Rights, Appreciation Rights, Restricted Shares, Restricted Stock Units, dividend equivalents or other awards pursuant to this Plan. If the Committee determines that a change in the business, operations, corporate structure or capital structure of the Company, or the manner in which it conducts its business, or other events or circumstances render the Management Objectives unsuitable, the Committee may in its discretion modify such Management Objectives or the goals or actual levels of achievement regarding the Management Objectives, in whole or in part, as the Committee deems appropriate and equitable.

(r) "Market Value per Share" means, as of any particular date, (i) for the purpose of determining the tax withholding due upon the vesting or settlement of Restricted Shares, Restricted Stock Units, Performance Shares and Performance Units and the related purpose of valuing Common Shares withheld from such awards to satisfy tax withholding obligations, the closing price of a Common Share as reported on the New York Stock Exchange on the trading day immediately preceding the day that such award vests as reported for that date (or, if there are no sales on such date, on the next preceding trading day during which a sale occurred); or (ii) for all other purposes under this Plan, the closing price of a Common Share as reported for that date on the New York Stock Exchange (or, if there are no sales on such date, on the next preceding trading day during which a sale occurred); *provided*, that in each case of (i) and (ii), if the Common Shares are not then listed on the New York Stock Exchange, then as reported on the principal U.S. national or regional securities exchange on which such securities are so listed or quoted, or if such securities are not so listed or quoted on a U.S. national or regional securities exchange or if for any date the Market Value per Share is not determinable by any of the foregoing means, including if there is no regular public trading market for the Common Shares, the per share fair market value of the Common Shares as determined in good faith by the Board.

(s) "Optionee" means the optionee named in an Evidence of Award evidencing an outstanding Option Right.

(t) "Option Price" means the purchase price payable on exercise of an Option Right.

(u) "Option Right" means the right to purchase Common Shares upon exercise of an award granted pursuant to **Section 4** of this Plan.

(v) "Participant" means a person who is selected by the Committee to receive benefits under this Plan and who is at the time (i) a non-employee Director, or (ii) an officer or other employee of the Company or any Subsidiary.

(w) "Performance Period" means, in respect of a Cash Incentive Award, Performance Share or Performance Unit, a period of time established pursuant to **Section 8** of this Plan within which the Management Objectives relating to such Cash Incentive Award, Performance Share or Performance Unit are to be achieved.

(x) "Performance Share" means a bookkeeping entry that records the equivalent of one Common Share awarded pursuant to **Section 8** of this Plan.

(y) "Performance Unit" means a bookkeeping entry awarded pursuant to **Section 8** of this Plan that records a unit equivalent to $1.00 or such other value as is determined by the Committee.

(z) "Plan" means this BKV Corporation 2024 Equity and Incentive Compensation Plan, as amended and restated as of March 5, 2026, and as may be further amended or amended and restated from time to time.

(aa) "Predecessor Plan" means the BKV Corporation 2021 Long Term Incentive Plan, adopted January 1, 2021, as amended.

(ab) "Restricted Shares" means Common Shares granted or sold pursuant to **Section 6** of this Plan as to which neither the substantial risk of forfeiture nor the prohibition on transfers has expired.

(ac) "Restricted Stock Units" means an award made pursuant to **Section 7** of this Plan of the right to receive Common Shares, cash or a combination thereof at the end of the applicable Restriction Period.

(ad) "Restriction Period" means the period of time during which Restricted Stock Units are subject to restrictions set forth in an Evidence of Award (including the relevant vesting schedules therein), as provided in **Section 7** of this Plan.

(ae) "Shareholder" means an individual or entity that owns one or more Common Shares.

(af) "Spread" means the excess of the Market Value per Share on the date when an Appreciation Right is exercised over the Base Price provided for with respect to the Appreciation Right.

(ag) "Subsidiary" means a corporation, company or other entity (i) more than 60% of whose outstanding shares or securities (representing the right to vote for the election of directors or other managing authority) are, or (ii) which does not have outstanding shares or securities (as may be the case in a partnership, joint venture, limited liability company, unincorporated association or other similar entity), but more than 60% of whose ownership interest representing the right generally to make decisions for such other entity is, now or hereafter, owned or controlled, directly or indirectly, by the Company.

(ah) "Voting Power" means, at any time, the combined voting power of the then-outstanding securities entitled to vote generally in the election of Directors in the case of the Company or members of the board of directors or similar body in the case of another entity.

3. **Shares Available Under this Plan.**

(a) Maximum Shares Available Under this Plan.

(i) Subject to adjustment as provided in **Section 11** of this Plan and the share counting rules set forth in **Section 3(b)** of this Plan, the number of Common Shares available under this Plan for awards of (A) Option Rights or Appreciation Rights, (B) Restricted Shares, (C) Restricted Stock Units, (D) Performance Shares or Performance Units, (E) awards contemplated by **Section 9** of this Plan, or (F) dividend equivalents paid with respect to awards made under this Plan will not exceed in the aggregate 7,500,000 Common Shares, which includes (x) the initial reserve of 5,000,000 Common Shares under this Plan and (y) an additional 2,500,000 Common Shares, approved in accordance with this Plan. Such shares may be shares of original issuance or treasury shares or a combination of the foregoing.

(ii) Subject to the share counting rules set forth in **Section 3(b)** of this Plan, the aggregate number of Common Shares available under **Section 3(a)(i)** of this Plan will be reduced by one Common Share for every one Common Share subject to an award granted under this Plan (for clarity, based on the maximum number of Common Shares issuable with respect to such award).

(b) Share Counting Rules.

(i) Except as provided in **Section 22** of this Plan, if any award granted under this Plan (in whole or in part) is cancelled or forfeited, expires, is settled for cash, or is unearned, the Common Shares subject to such award will, to the extent of such cancellation, forfeiture, expiration, cash settlement, or unearned amount, again be available under **Section 3(a)(i)** above.

(ii) Notwithstanding anything to the contrary contained in this Plan: (A) Common Shares withheld by the Company, tendered or otherwise used in payment of the Option Price of an Option Right will not be added (or added back, as applicable) to the aggregate number of Common Shares available under **Section 3(a)(i)** of this

Plan; (B) Common Shares withheld by the Company, tendered or otherwise used to satisfy tax withholding will not be added (or added back, as applicable) to the aggregate number of Common Shares available under **Section 3(a)(i)** of this Plan; (C) Common Shares subject to a share-settled Appreciation Right that are not actually issued in connection with the settlement of such Appreciation Right on the exercise thereof will not be added (or added back, as applicable) to the aggregate number of Common Shares available under **Section 3(a)(i)** of this Plan; and (D) Common Shares reacquired by the Company on the open market or otherwise using cash proceeds from the exercise of Option Rights will not be added (or added back, as applicable) to the aggregate number of Common Shares available under **Section 3(a)(i)** of this Plan.

(iii) If, under this Plan, a Participant has elected to give up the right to receive compensation in exchange for Common Shares based on fair market value, such Common Shares will not count against the aggregate limit under **Section 3(a)(i)** of this Plan.

(c) Non-Employee Director Compensation Limit. Notwithstanding anything to the contrary contained in this Plan, in no event will any non-employee Director in any one calendar year be granted compensation for such service having an aggregate maximum value (measured at the Date of Grant as applicable, and calculating the value of any awards based on the grant date fair value for financial reporting purposes) in excess of $750,000.

4. **Option Rights.** The Committee may, from time to time and upon such terms and conditions as it may determine, authorize the granting to Participants of Option Rights. Each such grant may utilize any or all of the authorizations, and will be subject to all of the requirements, contained in the following provisions:

(a) Each grant will specify the number of Common Shares to which it pertains subject to the limitations set forth in **Section 3** of this Plan.

(b) Each grant will specify an Option Price per Common Share, which Option Price (except with respect to awards under **Section 22** of this Plan) may not be less than the Market Value per Share on the Date of Grant.

(c) Each grant will specify whether the Option Price will be payable (i) in cash, by check acceptable to the Company or by wire transfer of immediately available funds, (ii) by the actual or constructive transfer to the Company of Common Shares owned by the Optionee having a value at the time of exercise equal to the total Option Price, (iii) subject to any conditions or limitations established by the Committee, by the withholding of Common Shares otherwise issuable upon exercise of an Option Right pursuant to a "net exercise" arrangement (it being understood that, solely for purposes of determining the number of treasury shares held by the Company, the Common Shares so withheld will not be treated as issued and acquired by the Company upon such exercise), (iv) by a combination of such methods of payment, or (v) by such other methods as may be approved by the Committee.

(d) To the extent permitted by law, any grant may provide for deferred payment of the Option Price from the proceeds of sale through a bank or broker on a date satisfactory to the Company of some or all of the Common Shares to which such exercise relates.

(e) Each grant will specify the period or periods of continuous service by the Optionee with the Company or any Subsidiary, if any, that is necessary before any Option Rights or installments thereof will vest. Option Rights may provide for continued vesting or the earlier vesting of such Option Rights, including in the event of the retirement, death, disability or termination of employment or service of a Participant or in the event of a Change in Control.

(f) Any grant of Option Rights may specify Management Objectives regarding the vesting of such rights.

(g) Option Rights granted under this Plan are not intended to qualify under Section 422 of the Code or any successor provision.

(h) No Option Right will be exercisable more than 10 years from the Date of Grant. The Committee may provide in any Evidence of Award for the automatic exercise of an Option Right upon such terms and conditions as established by the Committee.

(i) Option Rights granted under this Plan shall not provide for any dividends or dividend equivalents thereon.

(j) Each grant of Option Rights will be evidenced by an Evidence of Award. Each Evidence of Award will be subject to this Plan and will contain such terms and provisions, consistent with this Plan, as the Committee may approve.

5. **Appreciation Rights.**

(a) The Committee may, from time to time and upon such terms and conditions as it may determine, authorize the granting to any Participant of Appreciation Rights. An Appreciation Right will be the right of the Participant to receive from the Company an amount determined by the Committee, which will be expressed as a percentage of the Spread (not exceeding 100%) at the time of exercise.

(b) Each grant of Appreciation Rights may utilize any or all of the authorizations, and will be subject to all of the requirements, contained in the following provisions:

(i) Each grant may specify that the amount payable on exercise of an Appreciation Right will be paid by the Company in cash, Common Shares or any combination thereof.

(ii) Each grant will specify the period or periods of continuous service by the Participant with the Company or any Subsidiary, if any, that is necessary before the Appreciation Rights or installments thereof will vest. Appreciation Rights may provide for continued vesting or the earlier vesting of such Appreciation Rights, including in the event of the retirement, death, disability or termination of employment or service of a Participant or in the event of a Change in Control.

(iii) Any grant of Appreciation Rights may specify Management Objectives regarding the vesting of such Appreciation Rights.

(iv) Appreciation Rights granted under this Plan shall not provide for any dividends or dividend equivalents thereon.

(v) Each grant of Appreciation Rights will be evidenced by an Evidence of Award. Each Evidence of Award will be subject to this Plan and will contain such terms and provisions, consistent with this Plan, as the Committee may approve.

(c) Also, regarding Appreciation Rights:

(i) Each grant will specify in respect of each Appreciation Right a Base Price, which (except with respect to awards under **Section 22** of this Plan) may not be less than the Market Value per Share on the Date of Grant; and

(ii) No Appreciation Right granted under this Plan may be exercised more than 10 years from the Date of Grant. The Committee may provide in any Evidence of Award for the automatic exercise of an Appreciation Right upon such terms and conditions as established by the Committee.

6. **Restricted Shares.** The Committee may, from time to time and upon such terms and conditions as it may determine, authorize the grant or sale of Restricted Shares to Participants. Each such grant or sale may utilize any or all of the authorizations, and will be subject to all of the requirements, contained in the following provisions:

(a) Each such grant or sale will constitute an immediate transfer of the ownership of Common Shares to the Participant in consideration of the performance of services, entitling such Participant to voting, dividend and other ownership rights, but subject to the substantial risk of forfeiture and restrictions on transfer hereinafter described.

(b) Each such grant or sale may be made without additional consideration or in consideration of a payment by such Participant that is less than the Market Value per Share on the Date of Grant.

(c) Each such grant or sale will provide that the Restricted Shares covered by such grant or sale will be subject to a "substantial risk of forfeiture" within the meaning of Section 83 of the Code for a period to be determined by the Committee on the Date of Grant or until achievement of Management Objectives referred to in **Section 6(e)** of this Plan.

(d) Each such grant or sale will provide that during or after the period for which such substantial risk of forfeiture is to continue, the transferability of the Restricted Shares will be prohibited or restricted in the manner and to the extent prescribed by the Committee on the Date of Grant (which restrictions may include rights of repurchase or first refusal of the

Company or provisions subjecting the Restricted Shares to a continuing substantial risk of forfeiture while held by any transferee).

(e) Any grant of Restricted Shares may specify Management Objectives regarding the vesting of such Restricted Shares.

(f) Notwithstanding anything to the contrary contained in this Plan, Restricted Shares may provide for continued vesting or the earlier vesting of such Restricted Shares, including in the event of the retirement, death, disability or termination of employment or service of a Participant or in the event of a Change in Control.

(g) Any such grant or sale of Restricted Shares may require that any and all dividends or other distributions paid thereon during the period of such restrictions be automatically deferred and/or reinvested in additional Restricted Shares, which will be subject to the same restrictions as the underlying award. For the avoidance of doubt, any such dividends or other distributions on Restricted Shares shall be deferred until, and paid contingent upon, the vesting of such Restricted Shares.

(h) Each grant or sale of Restricted Shares will be evidenced by an Evidence of Award. Each Evidence of Award will be subject to this Plan and will contain such terms and provisions, consistent with this Plan, as the Committee may approve. Unless otherwise directed by the Committee, (i) all certificates representing Restricted Shares will be held in custody by the Company until all restrictions thereon will have lapsed, together with a stock power or powers executed by the Participant in whose name such certificates are registered, endorsed in blank and covering such shares or (ii) all Restricted Shares will be held at the Company's transfer agent in book entry form with appropriate restrictions relating to the transfer of such Restricted Shares.

7. **Restricted Stock Units.** The Committee may, from time to time and upon such terms and conditions as it may determine, authorize the granting or sale of Restricted Stock Units to Participants. Each such grant or sale may utilize any or all of the authorizations, and will be subject to all of the requirements, contained in the following provisions:

(a) Each such grant or sale will constitute the agreement by the Company to deliver Common Shares or 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 achievement regarding Management Objectives) during the Restriction Period as the Committee may specify.

(b) Each such grant or sale may be made without additional consideration or in consideration of a payment by such Participant that is less than the Market Value per Share on the Date of Grant.

(c) Notwithstanding anything to the contrary contained in this Plan, Restricted Stock Units may provide for continued vesting or the earlier lapse or other modification of the Restriction Period, including in the event of the retirement, death, disability or termination or employment of service of a Participant or in the event of a Change in Control, in each case as determined by the Committee.

(d) During the Restriction Period, the Participant will have no right to transfer any rights under his or her award and will have no rights of ownership in the Common Shares deliverable upon payment of the Restricted Stock Units and will have no right to vote them, but the Board may, at or after the Date of Grant, authorize the payment of dividend equivalents on such Restricted Stock Units, on a deferred and contingent basis, either in cash or in additional Common Shares; provided, however, that dividend equivalents or other distributions on Common Shares underlying Restricted Stock Units shall be deferred until and paid contingent upon the vesting of such Restricted Stock Units.

(e) Each grant or sale of Restricted Stock Units will specify the time and manner of payment of the Restricted Stock Units that have been earned. Each grant or sale will specify that the amount payable with respect thereto will be paid by the Company in Common Shares or cash, or a combination thereof.

(f) Each grant or sale of Restricted Stock Units will be evidenced by an Evidence of Award. Each Evidence of Award will be subject to this Plan and will contain such terms and provisions, consistent with this Plan, as the Committee may approve.

8. **Cash Incentive Awards, Performance Shares and Performance Units.** The Committee may, from time to time and upon such terms and conditions as it may determine, authorize the granting of Cash Incentive Awards, Performance Shares and Performance Units. Each such grant may utilize any or all of the authorizations, and will be subject to all of the requirements, contained in the following provisions:

(a) Each grant will specify the number or amount of Performance Shares or Performance Units, or amount payable with respect to a Cash Incentive Award, to which it pertains, which number or amount may be subject to adjustment to reflect changes in compensation or other factors.

(b) The Performance Period with respect to each Cash Incentive Award or grant of Performance Shares or Performance Units will be such period of time as will be determined by the Committee, which may be subject to continued vesting or earlier lapse or other modification, including in the event of the retirement, death, disability or termination of employment or service of a Participant or in the event of a Change in Control, in each case as determined by the Committee.

(c) Each grant of a Cash Incentive Award, Performance Shares or Performance Units will specify Management Objectives regarding the earning of the award.

(d) Each grant will specify the time and manner of payment of a Cash Incentive Award, Performance Shares or Performance Units that have been earned.

(e) The Board may, on the Date of Grant of Performance Shares or Performance Units, provide for the payment of dividend equivalents to the holder thereof either in cash or in additional Common Shares, which dividend equivalents shall be subject to deferral and payment on a contingent basis based on the Participant’s earning and vesting of the

Performance Shares or Performance Units, as applicable, with respect to which such dividend equivalents are paid.

(f) Each grant of a Cash Incentive Award, Performance Shares or Performance Units will be evidenced by an Evidence of Award. Each Evidence of Award will be subject to this Plan and will contain such terms and provisions, consistent with this Plan, as the Committee may approve.

9. **Other Awards.**

(a) Subject to applicable law and the applicable limits set forth in **Section 3** of this Plan, the Committee may authorize the grant to any Participant of Common Shares or such 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, Common Shares or factors that may influence the value of such shares, including, without limitation, convertible or exchangeable debt securities, other rights convertible or exchangeable into Common Shares, purchase rights for Common Shares, awards with value and payment contingent upon performance of the Company or specified subsidiaries, affiliates or other business units thereof or any other factors designated by the Committee, and awards valued by reference to the book value of the Common Shares or the value of securities of, or the performance of specified subsidiaries or affiliates or other business units of the Company. The Committee will determine the terms and conditions of such awards. Common Shares delivered pursuant to an award in the nature of a purchase right granted under this **Section 9** will be purchased for such consideration, paid for at such time, by such methods, and in such forms, including, without limitation, Common Shares, other awards, notes or other property, as the Committee determines.

(b) Cash awards, as an element of or supplement to any other award granted under this Plan, may also be granted pursuant to this **Section 9**.

(c) The Committee may authorize the grant of Common Shares as a bonus, or may authorize the grant of other awards in lieu of obligations of the Company or a Subsidiary to pay cash or deliver other property under this Plan or under other plans or compensatory arrangements, subject to such terms as will be determined by the Committee in a manner that complies with Section 409A of the Code.

(d) The Committee may, at or after the Date of Grant, authorize the payment of dividends or dividend equivalents on awards granted under this **Section 9** on a deferred and contingent basis, either in cash or in additional Common Shares; provided, however, that dividend equivalents or other distributions on Common Shares underlying awards granted under this **Section 9** shall be deferred until and paid contingent upon the earning and vesting of such awards.

(e) Each grant of an award under this **Section 9** will be evidenced by an Evidence of Award. Each such Evidence of Award will be subject to this Plan and will contain such terms and provisions, consistent with this Plan, as the Committee may approve, and will specify the time and terms of delivery of the applicable award.

(f) Notwithstanding anything to the contrary contained in this Plan, awards under this **Section 9** may provide for the earning or vesting of, or earlier elimination of restrictions applicable to, such award, including in the event of the retirement, death, disability or termination of employment or service of a Participant or in the event of a Change in Control.

10. **Administration of this Plan.**

(a) This Plan will be administered by the Committee; provided, that, with respect to awards to non-employee Directors, the Board shall have the same powers and authorities as the Committee and may, in its discretion, exercise such powers in lieu of the Committee.

(b) The interpretation and construction by the Board or the Committee, as applicable, of any provision of this Plan (including, without limitation, Section 11 and Section 18) or of any Evidence of Award (or related documents) and any determination by the Board or the Committee pursuant to any provision of this Plan or of any such agreement, notification or document will be final and conclusive. No member of the Board or the Committee shall be liable for any such action or determination made in good faith. In addition, each of the Board and Committee is authorized to take any action it determines in its sole discretion to be appropriate subject only to the express limitations contained in this Plan, and no authorization in any Plan section or other provision of this Plan is intended or may be deemed to constitute a limitation on the authority of the Board or the Committee.

(c) To the extent permitted by law, the Committee may delegate to one or more officers of the Company such administrative duties or powers as it may deem advisable, and the Committee or any officer of the Company to whom duties or powers have been delegated as aforesaid, may employ, at the Company's cost and expense, one or more persons to render advice with respect to any responsibility the Committee or such officer may have under this Plan. The Committee may, by resolution, authorize one or more officers of the Company to do one or both of the following on the same basis as the Committee: (i) designate employees to be recipients of awards under this Plan; and (ii) determine the size of any such awards; provided, however, that (A) the Committee will not delegate such responsibilities to any such officer for awards granted to an employee who is an officer (for purposes of Section 16 of the Exchange Act), a Director, or a more than 10% "beneficial owner" (as such term is defined in Rule 13d-3 promulgated under the Exchange Act) of any class of the Company's equity securities that is registered pursuant to Section 12 of the Exchange Act, as determined by the Committee in accordance with Section 16 of the Exchange Act; (B) the resolution providing for such authorization shall set forth the total number of Common Shares such officer(s) may grant; and (C) the officer(s) will report periodically to the Committee regarding the nature and scope of the awards granted pursuant to the authority delegated.

11. **Adjustments.** The Committee shall make or provide for such adjustments in the number of and kind of Common Shares covered by outstanding Option Rights, Appreciation Rights, Restricted Shares, Restricted Stock Units, Performance Shares and Performance Units granted hereunder and, if applicable, in the number of and kind of Common Shares covered by

other awards granted pursuant to **Section 9** of this Plan, in the Option Price and Base Price provided in outstanding Option Rights and Appreciation Rights, respectively, in Cash Incentive Awards, and in other award terms, as the Committee, in its sole discretion, exercised in good faith, determines is equitably required 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 the capital structure of the Company, (b) any 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 (c) any other corporate transaction or event having an effect similar to any of the foregoing. Moreover, in the event of any such transaction or event, the Committee may provide in substitution for any or all outstanding awards under this Plan such alternative consideration (including cash), if any, as it, in good faith, may determine to be equitable in the circumstances and shall 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 Option Right or Appreciation Right with an Option Price or Base Price, respectively, greater than the consideration offered in connection with any such transaction or event, the Committee may in its discretion elect to cancel such Option Right or Appreciation Right without any payment to the person holding such Option Right or Appreciation Right. The Committee shall also make or provide for such adjustments in the number of Common Shares specified in **Section 3** of this Plan as the Committee in its sole discretion, exercised in good faith, determines is appropriate to reflect any transaction or event described in this **Section 11**.

12. **Change in Control**.

(a) Upon a Change in Control, the Committee, acting in its sole discretion without the consent or approval of any Participant, may (i) provide that an outstanding Award shall be assumed by, or a substitute award shall be granted by, the surviving entity resulting from a transaction described in **Section 12(b)(iii)**, (ii) provide for acceleration of the vesting and exercisability of, or lapse of restrictions, in whole or in part, with respect to, an Award and, if the transaction is a cash merger, provide for the termination of any portion of the Award that remains unexercised at the time of such transaction, (iii) cancel an Award in exchange for a cash payment in an amount that the Committee shall determine in its sole discretion is equal to the fair market value of such Award on the date of such event, which in the case of Option Rights or Appreciation Rights shall be the excess of the Market Value of Shares on such date over the Option Price or Base Price, as applicable, of such Award (it being understood that, for each Option Right or Appreciation Right with an Option Price or Base Price, respectively, equal to or greater than the consideration offered in connection with the Change in Control, the Committee may in its discretion elect to cancel such Option Right or Appreciation Right without any payment to the person holding such Option Right or Appreciation Right), or (iv) make such adjustments, if any, to the Awards then outstanding as the Committee deems appropriate to reflect such Change in Control. The Committee may effect one or more of such alternatives, which may vary among individual Participants and which may vary among Awards held by any individual Participant:

(b) For purposes of this Plan, except as may be otherwise prescribed by the Committee in an Evidence of Award made under this Plan, a "Change in Control" will be deemed to have occurred upon the occurrence (after the Effective Date) of any of the following events:

(i) the acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Exchange Act) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of Company Voting Securities where such acquisition causes such Person to own 40% or more of the combined voting power of the then outstanding Company Voting Securities; provided, however, that for purposes of this subsection (a), the following acquisitions shall not be deemed to result in a Change in Control: (i) any acquisition by the Company or a wholly-owned subsidiary of the Company, (ii) any acquisition directly from the Company that is approved by the Board prior to the transaction, (iii) any acquisition by any Exempt Person or by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company or (iv) any acquisition by any corporation pursuant to a transaction that complies with clauses (A) and (B) of Section 12(b)(iii) below;

(ii) the replacement of a majority of the Board over a two-year period of the directors who constituted the Board at the beginning of such period, and such replacement shall not have been approved by a vote of at least a majority of the Board then still in office who either were members of such Board at the beginning of such period or whose election as a member of such Board was previously so approved; provided, that any such person whose initial assumption of office is in connection with an actual or threatened election contest relating to the election of members of the Board or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board, including by reason of agreement intended to avoid or settle any such actual or threatened contest or solicitation, shall not be considered to have been so approved;

(iii) the consummation of a reorganization, merger or consolidation or the sale or other disposition of all or substantially all of the assets of the Company, whether in one or a series of related transactions, ("Business Combination") excluding, however, such a Business Combination pursuant to which (A) the individuals and entities who were the beneficial owners of the outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 50% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors of the entity resulting from such Business Combination in substantially the same proportions as their ownership of the Common Shares and Company Voting Securities immediately prior to such Business Combination (including, without limitation, an entity that as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries), and (B) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

(iv) approval by the Shareholders of a complete liquidation or dissolution of the Company except pursuant to a Business Combination that complies with clauses (A) and (B) of Section 12(b)(iii) above.

13. **Detrimental Activity and Recapture Provisions**. Any Evidence of Award may reference a clawback policy of the Company or provide for the cancellation or forfeiture of an award or the forfeiture and repayment to the Company of any gain related to an award, or other provisions intended to have a similar effect, upon such terms and conditions as may be determined by the Committee from time to time, if a Participant, either (a) during employment or other service with the Company or a subsidiary, or (b) within a specified period after termination of such employment or service, engages in any detrimental activity, as described in the applicable Evidence of Award or such clawback policy. In addition, notwithstanding anything in this Plan to the contrary, any Evidence of Award or such clawback policy may also provide for the cancellation or forfeiture of an award or the forfeiture and repayment to the Company of any Common Shares issued under and/or any other benefit related to an award, or other provisions intended to have a similar effect, including upon such terms and conditions as may be required by the Committee or under Section 10D of the Exchange Act and any applicable rules or regulations promulgated by the Securities and Exchange Commission or any national securities exchange or national securities association on which the Common Shares may be traded.

14. **Non-U.S. Participants.** In order to facilitate the making of any grant or combination of grants under this Plan, the Committee may provide for such special terms for awards to Participants who are foreign nationals or who are employed by the Company or any Subsidiary outside of the United States of America or who provide services to the Company or any Subsidiary under an agreement with a foreign nation or agency, as the Committee may consider necessary or appropriate to accommodate differences in local law, tax policy or custom. Moreover, the Committee may approve such supplements to or amendments, restatements or alternative versions of this Plan (including sub-plans) as it may consider necessary or appropriate for such purposes, without thereby affecting the terms of this Plan as in effect for any other purpose, and the secretary or other appropriate officer of the Company may certify any such document as having been approved and adopted in the same manner as this Plan. No such special terms, supplements, amendments or restatements, however, will include any provisions that are inconsistent with the terms of this Plan as then in effect unless this Plan could have been amended to eliminate such inconsistency without further approval by the Shareholders.

15. **Transferability.**

(a) Except as otherwise determined by the Committee, and subject to compliance with **Section 17(b)** of this Plan and Section 409A of the Code, no Option Right, Appreciation Right, Restricted Share, Restricted Stock Unit, Performance Share, Performance Unit, Cash Incentive Award, award contemplated by **Section 9** of this Plan or dividend equivalents paid with respect to awards made under this Plan will be transferable by the Participant except by will or the laws of descent and distribution. In no event will any such award granted under this Plan be transferred for value. Where transfer is permitted, references to "Participant" shall be construed, as the Committee deems appropriate, to include any permitted transferee to whom such award is transferred. Except as otherwise determined by the Committee, Option Rights and Appreciation Rights will be exercisable during the Participant's lifetime only by him or her or, in the event of the

Participant’s legal incapacity to do so, by his or her guardian or legal representative acting on behalf of the Participant in a fiduciary capacity under state law or court supervision.

(b) The Committee may specify on the Date of Grant that part or all of the Common Shares that are (i) to be issued or transferred by the Company upon the exercise of Option Rights or Appreciation Rights, upon the termination of the Restriction Period applicable to Restricted Stock Units or upon payment under any grant of Performance Shares or Performance Units or (ii) no longer subject to the substantial risk of forfeiture and restrictions on transfer referred to in **Section 6** of this Plan, will be subject to further restrictions on transfer, including minimum holding periods.

16. **Withholding Taxes.** To the extent that the Company is required to withhold federal, state, local or foreign taxes or other amounts in connection with any payment made or benefit realized by a Participant or other person under this Plan, and the amounts available to the Company for such withholding are insufficient, it will be a condition to the receipt of such payment or the realization of such benefit that the Participant or such other person make arrangements satisfactory to the Company for payment of the balance of such taxes or other amounts required to be withheld, which arrangements may include relinquishment of a portion of such benefit. If a Participant’s benefit is to be received in the form of Common Shares, and such Participant fails to make arrangements satisfactory to the Company for the payment of taxes or other amounts, then, unless otherwise determined by the Committee, the Company may (a) require the Participant to satisfy such requirements by a broker-assisted sale, and/or (b) withhold Common Shares having a value equal to the amount required to be withheld, and/or (c) deduct from any amount otherwise payable in cash (whether related to the award or otherwise) to the Participant (or the Participant’s personal representative or beneficiary, as the case may be) the minimum amount required to be withheld with respect to such award event or payment; provided, however, that (x) if such withholding pursuant to clause (b) would cause a material adverse effect on the Company’s liquidity position and impair the Company’s ability to operate in the normal course of business, then such withholding shall not be permitted unless otherwise approved by the Board, and (y) such deduction pursuant to clause (c) shall be permitted only if there is a good faith determination by the Board that both (I) a broker-assisted sale is not reasonably or sufficiently available and (II) absent such deduction, the Company’s payment of the amount required to be withheld would adversely and materially affect the Company’s liquidity position and impair the Company’s ability to operate in the normal course of business.

17. **Compliance with Section 409A of the Code.**

(a) To the extent applicable, it is intended that this Plan and any grants made hereunder be exempt from the provisions of Section 409A of the Code or, if not so exempt, that this Plan and any grants made hereunder comply with the provisions of Section 409A of the Code, so that the income inclusion provisions of Section 409A(a)(1) of the Code do not apply to the Participants. This Plan and any grants made hereunder will be administered in a manner consistent with this intent. Any reference in this Plan to Section 409A of the Code will also include any regulations or any other formal guidance promulgated with respect to such section by the U.S. Department of the Treasury or the Internal Revenue Service.

(b) Neither a Participant nor any of a Participant’s creditors or beneficiaries will have the right to subject any deferred compensation (within the meaning of Section 409A of the Code) payable under this Plan and grants hereunder to any anticipation, alienation, sale, transfer, assignment, pledge, encumbrance, attachment or garnishment. Except as permitted under Section 409A of the Code, any deferred compensation (within the meaning of Section 409A of the Code) payable to a Participant or for a Participant's benefit under this Plan and grants hereunder may not be reduced by, or offset against, any amount owed by a Participant to the Company or any of its subsidiaries.

(c) If, at the time of a Participant's separation from service (within the meaning of Section 409A of the Code), (i) the Participant will be a specified employee (within the meaning of Section 409A of the Code and using the identification methodology selected by the Company from time to time) and (ii) the Company makes a good faith determination that an amount payable hereunder constitutes deferred compensation (within the meaning of Section 409A of the Code) the payment of which is required to be delayed pursuant to the six-month delay rule set forth in Section 409A of the Code in order to avoid taxes or penalties under Section 409A of the Code, then the Company will not pay such amount on the otherwise scheduled payment date but will instead pay it, without interest, on the tenth business day of the seventh month after such separation from service.

(d) Solely with respect to any award that constitutes nonqualified deferred compensation subject to Section 409A of the Code and that is payable on account of a Change in Control (including any installments or stream of payments that are accelerated on account of a Change in Control), a Change in Control shall occur only if such event also constitutes a "change in the ownership," "change in effective control," and/or a "change in the ownership of a substantial portion of assets" of the Company as those terms are defined under Treasury Regulation §1.409A-3(i)(5), but only to the extent necessary to establish a time and form of payment that complies with Section 409A of the Code, without altering the definition of Change in Control for any purpose in respect of such award.

(e) Notwithstanding any provision of this Plan and grants hereunder to the contrary, in light of the uncertainty with respect to the proper application of Section 409A of the Code, the Company reserves the right to make amendments to this Plan and grants hereunder as the Company deems necessary or desirable to avoid the imposition of taxes or penalties under Section 409A of the Code. In any case, a Participant will be solely responsible and liable for the satisfaction of all taxes and penalties that may be imposed on a Participant or for a Participant's account in connection with this Plan and grants hereunder (including any taxes and penalties under Section 409A of the Code), and neither the Company nor any of its affiliates will have any obligation to indemnify or otherwise hold a Participant harmless from any or all of such taxes or penalties.

18. **Amendments.**

(a) The Board may at any time and from time to time amend this Plan in whole or in part; provided, however, that if an amendment to this Plan, for purposes of applicable stock exchange rules and except as permitted under **Section 11** of this Plan, (i) would materially increase the benefits accruing to Participants under this Plan, (ii) would materially increase the number of securities which may be issued under this Plan, (iii) would materially modify the requirements for participation in this Plan, or (iv) must otherwise be approved by the Shareholders in order to comply with applicable law or the rules of the New York Stock Exchange or, if the Common Shares are not traded on the New York Stock Exchange, the principal national securities exchange upon which the Common Shares are traded or quoted, all as determined by the Board, then, such amendment will be subject to the applicable Shareholder approval and will not be effective unless and until such approval has been obtained.

(b) Except in connection with a corporate transaction or event described in **Section 11** of this Plan or in connection with a Change in Control, the terms of outstanding awards may not be amended to reduce the Option Price of outstanding Option Rights or the Base Price of outstanding Appreciation Rights, or cancel outstanding "underwater" Option Rights or Appreciation Rights (including following a Participant's voluntary surrender of "underwater" Option Rights or Appreciation Rights) in exchange for cash, other awards or Option Rights or Appreciation Rights with an Option Price or Base Price, as applicable, that is less than the Option Price of the original Option Rights or Base Price of the original Appreciation Rights, as applicable, without Shareholder approval. This **Section 18(b)** is intended to prohibit the repricing of "underwater" Option Rights and Appreciation Rights and will not be construed to prohibit the adjustments provided for in **Section 11** or **Section 12** of this Plan. Notwithstanding any provision of this Plan to the contrary, this **Section 18(b)** may not be amended without approval by the Shareholders.

(c) If permitted by Section 409A of the Code, but subject to the paragraph that follows, including in the case of termination of employment or service, or in the case of unforeseeable emergency or other circumstances or in the event of a Change in Control, to the extent a Participant holds an Option Right or Appreciation Right not immediately exercisable in full, or any Restricted Shares as to which the substantial risk of forfeiture or the prohibition or restriction on transfer has not lapsed, or any Restricted Stock Units as to which the Restriction Period has not been completed, or any Cash Incentive Awards, Performance Shares or Performance Units which have not been fully earned, or any dividend equivalents or other awards made pursuant to **Section 9** of this Plan subject to any vesting schedule or transfer restriction, or who holds Common Shares subject to any transfer restriction imposed pursuant to **Section 15(b)** of this Plan, the Committee may, in its sole discretion, provide for continued vesting or accelerate the time at which such Option Right, Appreciation Right or other award may vest or be exercised or the time at which such substantial risk of forfeiture or prohibition or restriction on transfer will lapse or the time when such Restriction Period will end or the time at which such Cash Incentive Awards, Performance Shares or Performance Units will be deemed to have been earned or the time when such transfer restriction will terminate or may waive any other limitation or requirement under any such award.

(d) Subject to **Section 18(b)** of this Plan, the Committee may amend the terms of any award theretofore granted under this Plan prospectively or retroactively. Except for adjustments made pursuant to **Section 11** of this Plan, no such amendment will materially impair the rights of any Participant without his or her consent. The Board may, in its discretion, terminate this Plan at any time. Termination of this Plan will not affect the rights of Participants or their successors under any awards outstanding hereunder and not exercised in full on the date of termination.

19. **Governing Law.** This Plan and all grants and awards and actions taken hereunder will be governed by and construed in accordance with the internal substantive laws of the State of Delaware.

20. **Effective Date/Termination.** This Plan was originally effective as of immediately prior to the time at which the registration statement covering the initial public offering of the Common Shares was declared effective by the Securities and Exchange Commission on September 25, 2024 (such date, the "Effective Date"). This Plan, as amended and restated herein, will become effective on March 5, 2026, the date of the applicable Shareholder approval. No grants will be made on or after the Effective Date under the Predecessor Plan, provided that outstanding awards granted under the Predecessor Plan will continue unaffected following the Effective Date. No grant will be made under this Plan on or after the tenth anniversary of the Effective Date, but all grants made prior to such date will continue in effect thereafter subject to the terms thereof and of this Plan. For clarification purposes, the terms and conditions of this Plan shall not apply to or otherwise impact previously granted and outstanding awards under the Predecessor Plan, as applicable.

21. **Miscellaneous Provisions.**

(a) The Company will not be required to issue any fractional Common Shares pursuant to this Plan. The Committee may provide for the elimination of fractions or for the settlement of fractions in cash.

(b) This Plan will not confer upon any Participant any right with respect to continuance of employment or other service with the Company or any Subsidiary, nor will it interfere in any way with any right the Company or any Subsidiary would otherwise have to terminate such Participant's employment or other service at any time.

(c) No award under this Plan may be exercised by the holder thereof if such exercise, and the receipt of cash or shares thereunder, would be, in the opinion of counsel selected by the Company, contrary to law or the regulations of any duly constituted authority having jurisdiction over this Plan.

(d) Absence on leave approved by a duly constituted officer of the Company or any of its Subsidiaries will not be considered interruption or termination of service of any employee for any purposes of this Plan or awards granted hereunder.

(e) No Participant will have any rights as a Shareholder with respect to any Common Shares subject to awards granted to him or her under this Plan prior to the date as of which he or she is actually recorded as the holder of such Common Shares upon the share records of the Company.

(f) The Committee may condition the grant of any award or combination of awards authorized under this Plan on the surrender or deferral by the Participant of his or her right to receive a cash bonus or other compensation otherwise payable by the Company or a Subsidiary to the Participant.

(g) Except with respect to Option Rights and Appreciation Rights, the Committee may permit Participants to elect to defer the issuance of Common Shares under this Plan pursuant to such rules, procedures or programs as it may establish for purposes of this Plan and which are intended to comply with the requirements of Section 409A of the Code. The Committee also may provide that deferred issuances and settlements include the crediting of dividend equivalents or interest on the deferral amounts.

(h) If any provision of this Plan is or becomes invalid or unenforceable in any jurisdiction, or would disqualify this Plan or any award under any law deemed applicable by the Committee, such provision will be construed or deemed amended or limited in scope to conform to applicable laws or, in the discretion of the Committee, it will be stricken and the remainder of this Plan will remain in full force and effect. Notwithstanding anything in this Plan or an Evidence of Award to the contrary, nothing in this Plan or in an Evidence of Award prevents a Participant from providing, without prior notice to the Company, information to governmental authorities regarding possible legal violations or otherwise testifying or participating in any investigation or proceeding by any governmental authorities regarding possible legal violations, and for purpose of clarity a Participant is not prohibited from providing information voluntarily to the Securities and Exchange Commission pursuant to Section 21F of the Exchange Act.

22. **Share-Based Awards in Substitution for Awards Granted by Another Company.** Notwithstanding anything in this Plan to the contrary:

(a) Awards may be granted under this Plan in substitution for or in conversion of, or in connection with an assumption of, stock options, stock appreciation rights, restricted shares, restricted stock units or other share or share-based awards held by awardees of an entity engaging in a corporate acquisition or merger transaction with the Company or any subsidiary. Any conversion, substitution or assumption will be effective as of the close of the merger or acquisition, and, to the extent applicable, will be conducted in a manner that complies with Section 409A of the Code. The awards so granted may reflect the original terms of the awards being assumed or substituted or converted for and need not comply with other specific terms of this Plan, and may account for Common Shares substituted for the securities covered by the original awards and the number of shares subject to the original awards, as well as any exercise or purchase prices applicable to the original awards, adjusted to account for differences in stock prices in connection with the transaction.

(b) In the event that a company acquired by the Company or any subsidiary or with which the Company or any subsidiary merges has shares available under a pre-existing plan previously approved by shareholders and not adopted in contemplation of such acquisition or merger, the shares available for grant pursuant to the terms of such plan (as adjusted, to the extent appropriate, to reflect such acquisition or merger) may be used for awards made after such acquisition or merger under this Plan; provided, however, that awards using such available shares may not be made after the date awards or grants could have been made under the terms of the pre-existing plan absent the acquisition or merger, and may only be made to individuals who were not employees or directors of the Company or any subsidiary prior to such acquisition or merger.

(c) Any Common Shares that are issued or transferred by, or that are subject to any awards that are granted by, or become obligations of, the Company under **Sections 22(a)** or **22(b)** of this Plan will not reduce the Common Shares available for issuance or transfer under this Plan or otherwise count against the limits contained in **Section 3** of this Plan. In addition, no Common Shares subject to an award that is granted by, or becomes an obligation of, the Company under **Sections 22(a)** or **22(b)** of this Plan, will be added to the aggregate limit contained in **Section 3(a)(i)** of this Plan.

Exhibit 10.30

BKV CORPORATION

EMPLOYMENT AGREEMENT

This Employment Agreement (the "**Agreement**") is effective as of the 3rd day of April, 2025 ("**Effective Date**"), regardless of the date the Agreement is executed, by and between BKV Corporation, a Delaware Corporation (hereinafter referred to as "**Employer**" or "**Company**"), and Dilanka Seimon (hereinafter referred to as "**Employee**"). Collectively, Employer and Employee shall be referred to as the "**Parties**."

A. Employer desires to engage Employee in the position of Chief Commercial Officer, based in Houston, Texas.

B. Employee is willing to be employed by Employer, and Employer is willing to employ Employee, on the terms and conditions set forth herein.

C. In consideration of the mutual covenants and promises of the Parties hereto, Employer and Employee agree as follows:

1. **Agreement to Employ and be Employed**: Employer hereby agrees to employ Employee and Employee hereby accepts and agrees to such employment.
2. **At-Will Employment**: ***Employee's employment is at-will.*** Nothing in this Agreement guarantees Employee employment with Employer for any specific period. This means that, subject to the provisions of this Agreement, Employer may terminate employee at any time with no advance notice, procedure, or formality and for any lawful reason. Similarly, subject to the provisions of this Agreement, Employee may resign his employment at any time and for any reason.
3. **Description of Employee's Duties**: Employee will be employed as Chief Commercial Officer. Employee's job duties are set forth in **Exhibit 1**. The position is exempt from overtime under both state and federal laws and regulations.
4. **Manner of Performance of Employee's Duties**: Employee shall be a full-time employee of Employer, shall devote his best efforts and entire business time, attention, and services exclusively to the business and affairs of Employer, and shall perform his duties as set forth in **Exhibit 1** with fidelity and to the best of his ability, experience, and talent. Employee shall also perform the duties of his position to the reasonable satisfaction of Employer.

   Employee will not engage in the performance of services for any other business or entity during the term of this Agreement
5. **Compensation**: In consideration of the services to be provided by Employer during employment, Employer shall compensate Employee as follows:
   a. During his employment, Employee shall receive the equivalent of an annual base salary of Five Hundred and Twenty Thousand dollars ($520,000.00), less applicable payroll deductions and required taxes and withholdings ("**Base Compensation**"), with partial periods prorated. Employee's Base Compensation shall be payable in equal periodic installments according to Employer's customary payroll practice. The Base Compensation is based on and intended to compensate Employee for all hours worked.
   b. During his employment, Employee may participate in Employer benefit plans and

programs described in the attached **Exhibit 2**, to the extent that Employer maintains such plans or programs and in accordance with the eligibility and participation criteria applicable to each such plan or program. Employee acknowledges that Employer has the right to change, modify, or eliminate benefits provided to its employees from time to time in Employer's sole discretion without notice to employees. As such, Employee acknowledges and agrees that this Agreement does not create a specific entitlement to any benefits, and that Employee will receive benefits at the same level as similarly situated employees of Employer.

c. During his employment, Employee may also, in Employer's sole discretion, receive compensation each calendar year in addition to his Base Compensation. Such additional compensation will be paid, if at all, in the form of an annual bonus ("**Annual Target Bonus**"), which Employer intends to fall between zero percent and ninety-five percent (0-95%) of the annual Base Compensation. The availability of any bonus will be determined based upon Employer's performance and will consider Employee's individual effort and satisfactory achievement of established performance goals. Any such Annual Target Bonus (if any) will be paid to Employee, in full and subject to applicable tax, not later than March 15 of the calendar year following the calendar year during which Employee performed the services that gave rise to that bonus. The bonus would be pro-rated based on Employee's hire date.

   Nothing in this provision (c) is intended to guarantee Employee the payment of a bonus in any amount

d. Paid Time Off (PTO). PTO includes vacation, sick, personal time, etc. Employee is eligible to accrue up to 30 days of PTO per year. Paid time off is accrued on a pro-rata basis at the rate of 1.15 days/Bi-Weekly throughout the year. Under Employer's policy, employees do not accrue PTO once they have earned their maximum paid time off hours per year. The accrual will resume once the amount of accrued PTO is less than the maximum possible accrual. Available PTO will automatically carry over into the new calendar year. Up to 10 days of accrued, unused paid time off will be paid out upon separation, unless otherwise required by law. Advanced but unaccrued paid time off will be deducted from an employee's final paycheck to the extent permitted by law and Employee hereby authorizes such deduction in accordance with applicable law and waives the right to presentment, notice and protest.

e. Long-Term Incentive. In addition, during Employee's employment, subject to final management and Compensation Committee of the Employer's Board of Directors approval, Employee shall be eligible to participate in the Employer's Long-Term Incentive Program ("**LTIP**") pursuant to the terms of the LTIP and grant agreements approved by the Compensation Committee. For the 2025 financial year of the Employer, subject to the approval of the Compensation Committee of the Employer's Board of Directors, Employee shall be granted an equity award under the LTIP that, on the date of grant, is valued at approximately One Million Five Hundred Thousand U.S. Dollars ($1,500,000.00) ("**Annual LTI Grant**"), with performance-based equity awards valued at target performance levels. It is the Company's intent to target an annual grant value of $1,500,000 to Employee after calendar year 2025 subject to approval of the Compensation Committee of the Employer's Board of Directors, in its sole and absolute discretion, and without any obligation of Employer to actually award such amount.

f. Sign on Bonus. In consideration of Employee agreeing to provide services pursuant to, and in compliance with, the Agreement, Company shall pay Employee an amount equal to One Million U.S. Dollars ($1,000,000) (the "**Sign on Bonus**"), less applicable payroll deductions and required taxes and withholdings, no later than April 30, 2025; provided that, if, Employee's employment with Company terminates for any reason prior to the first (1st) anniversary of the Effective Date or if Employee breaches any of the material terms and conditions set forth in this Agreement during such one- year period, Employee shall immediately repay the Sign on Bonus to the Company. Notwithstanding the foregoing, if prior to the first (1st) anniversary Employee is terminated by the Company without Cause or Employee terminates his employment for Good Reason, Employee shall retain the entire Retention Bonus.

6. **<u>Protection of Trade Secrets and Confidential Information</u>**: Whereas Company engages in natural gas exploration and production to produce low impact, sustainable carbon-based energy, Employee acknowledges that, in the course of performing and fulfilling Employee's duties hereunder, Employee may have access to and be entrusted with nonpublic information, substantial trade secrets, confidential information, and important opportunities and benefits belonging to, developed by, licensed by, or otherwise in the possession of, Company, its Affiliates or its clients. "**Affiliate**" is defined as all parent, sister and subsidiary companies.

    a. Employee understands and acknowledges that Company has invested, and continues to invest, substantial time, money and specialized knowledge into developing its intellectual property and other resources, training its employees, and improving its business offerings. Employee understands and acknowledges that as a result of these efforts, Company has created, and continues to use and create Confidential Information and trade secrets that provide the Company with a competitive advantage over others in the marketplace. Employee acknowledges and agrees that, during the course of Employee's employment with Company, Employee will have access to and learn about Company Confidential Information and trade secrets. Employee acknowledges and agrees that Company is in a highly competitive business and that the Confidential Information and trade secrets of Company as set forth herein would give a competing business an unfair advantage against Company if such Confidential Information or trade secrets were disclosed to a competing business.

    b. Employee understands that "**Confidential Information**" means any of Company's and its Affiliates' confidential and proprietary information including, without limitation, (i) information not generally known outside Company such as information that is unique to the Company, (ii) any information, processes, plans, data calculations, software storage media or other compilation of information, patents, patent applications, copyrights, "know-how," trade secrets, customer lists, details of client or consultant contracts, pricing policies, operational methods, marketing plans or strategies, product development techniques or plans, business acquisition plans, any portion or phase of any scientific or technical information, ideas, discoveries, designs, inventions, creative works, computer programs (including source of object codes), processes, formulae, improvements or other proprietary or intellectual property of the Employer, whether or not in written or tangible form, and whether or not registered or labeled as confidential, and including all files, records, manuals, books, catalogues, memoranda, notes, summaries, plans, reports, records, documents and other evidence thereof, and (iii) any trade secret information as defined in the Colorado Uniform Trade Secrets Act, C.R.S. § 7-74-101 et seq. or other applicable state law. Employee further understands that the above list is not exhaustive, and that Confidential Information also includes other information that is marked or otherwise identified or treated as confidential or proprietary, that would otherwise appear to a reasonable person to be confidential or proprietary in the context and circumstances in which the information is known or used, or that is customarily treated as confidential or proprietary by the Company. Employee understands and agrees that Confidential Information includes information developed by Employee in the course of Employee's employment by the Company as if the Company furnished the same Confidential Information to Employee in the first instance. Employee further understands that Confidential Information does not include any of the items listed in this Section 6.b. which arise from Employee's general training, knowledge, skill, or experience, whether gained on the job or otherwise, information that is readily ascertainable to the public or has become publicly known through no wrongful act of Employee or of others who were under confidentiality obligations as to the item or items involved, or information that Employee otherwise has a right to disclose as legally protected conduct.

c. Employee agrees at all times during the term of Employee's employment and thereafter, to hold in strictest confidence, and not to use, except for the benefit of Company, and not to disclose, copy, or disseminate to any person, firm or corporation, any Confidential Information of Company, regardless of the medium on which the Confidential Information is stored (hard copy, electronic, or other format). This provision does not prohibit disclosure of information that arises from Employee's general training, knowledge, skill, or experience, whether gained on the job or otherwise, information that is readily ascertainable to the public, or information that Employee otherwise has a right to disclose as legally protected conduct. At the request of Employer, Employee agrees to deliver to Employer, at any time during Employee's employment, or thereafter, all Confidential Information which Employee may possess or control.

d. Employee understands and acknowledges that nothing in this Agreement shall be construed to prohibit Employee from (i) communicating with, filing a charge or complaint with, responding to an inquiry from, participating in an investigation or proceeding conducted by, providing testimony to, or reporting violations of law or regulation to the Securities and Exchange Commission, the Financial Industry Regulation Authority, the National Labor Relations Board, the Equal Employment Opportunity Commission, the Occupational Safety and Health Administration, or any other federal, state, or local governmental authority or agency, including, but not limited to, regarding this Agreement or otherwise, and including providing documents or other information to such agency without notice to Company, (ii) truthfully responding to or complying with a subpoena, court order, or other legal process (a) when required to do so by a lawful order of a court of competent jurisdiction, any governmental authority or agency, or any recognized subpoena power, or (b) when doing so is necessary to prosecute Employee's rights against Company or to defend Employee against any allegations, or (iii) exercising any rights Employee may have under applicable labor laws to engage in concerted activity with other employees. For the avoidance of doubt, nothing herein shall limit Employee's eligibility to receive an award out of monetary sanctions collected by any governmental authority or agency as provided by applicable whistleblower programs. Under the U.S. Defend Trade Secrets Act of 2016, 18 U.S.C. § 1833(b) (the "**DTSA**"), persons who disclose trade secrets in connection with lawsuits or other proceedings under seal (including lawsuits alleging retaliation), or in confidence to a federal, state or local government official, or attorney, solely for the purpose of reporting or investigating a suspected violation of law, enjoy immunity from civil and criminal liability under state and federal trade secrets laws for such disclosure. Employee acknowledges that Employee has hereby received adequate notice of this immunity and that nothing in this Agreement is intended to conflict with the DTSA or create liability for disclosures of trade secrets that are expressly allowed by the DTSA. "An individual shall not be held criminally or civilly liable under any federal or state trade secret law for the disclosure of a trade secret that is made in confidence to a federal, state, or local government official or to an attorney solely for the purpose of reporting or investigating a suspected violation of law. An individual shall not be held criminally or civilly liable under any federal or state trade secret law for the disclosure of a trade secret that is made in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal. An individual who files a lawsuit for retaliation by an employer for reporting a suspected violation of law may disclose the trade secret to the attorney of the individual and use the trade secret information in the court proceeding, if the individual files any document containing the trade secret under seal; and does not disclose the trade secret, except pursuant to a court order."

e. Nothing in this Agreement shall be construed to prevent disclosure of Confidential Information as may be required by applicable law or regulation, or pursuant to the valid order of a court of competent jurisdiction or an authorized government agency, provided that the disclosure does not exceed the extent of disclosure required by such law, regulation, or order; provided, however, that in the event such disclosure is required by applicable law, Employee shall provide Employer with prompt written notice of such requirement, prior to making any disclosure, so that Employer may seek an appropriate protective order, and Employee only shall disclose information as necessary to comply with legal process. Nothing in this Agreement in any way prohibits or is intended to restrict or impede, and shall not be interpreted or understood as restricting or impeding, employees from discussing the terms and conditions of their employment with co-workers or union representatives, exercising their rights under Section 7 of the National Labor Relations Act, and/or exercising protected rights to the extent that such rights cannot be waived by agreement.

7. **Inventions, Ideas, and Other Intellectual Developments**: In view of the purposes of Employer and the need to secure for Employer and/or Interested Parties (defined below) their right to Intellectual Developments (defined below) related to the business of Employer and/or such Interested Party, Employee understands that Employer must be in a position to use, assign, and otherwise dispose of Intellectual Developments made by its staff members and employees. Accordingly, , Employee shall promptly disclose to Employer and, when requested, furnish to Employer a complete record of every discovery, invention, improvement, innovation, design, analysis, reports, drawings, copyright, intellectual property right and other definite and useful idea or compilation of information of value (individually and collectively an "**Intellectual Development**"), which Employee may make or originate, individually or with others, at any time during the term of Employee's employment by Employer. Employee hereby assigns to Employer or its nominee the entire rights throughout the world to such Intellectual Developments which relate to the current or potential business or activities of Employer or any Interested Parties or which results from Employee's work with Employer. The term "**Interested Parties**" means any person having a business relationship with Company where the relationship gives rise to a claim by that person to some interest in Intellectual Developments made by employees and associates of Employer or its Affiliates.

8. **Cooperation**: Employee shall fully cooperate with Employer or its designees in securing, in the name of Company or its designees, rights with respect to the Intellectual Developments described in Section 7 above, in all countries. Employee shall promptly execute and deliver such documents and take all other actions as Employer may request in order to enable Employer or its designees to accomplish the above, at any time during or after Employee's employment.

9. **Shop Rights and Holdover**: Employee agrees that Employer or its designees shall be entitled to shop rights to any Intellectual Developments conceived or made by Employee that is not related to the Employer's trade secrets and/or Confidential Information but conceived or made on Company time or with the use of Employer's facilities or materials. Employee further agrees that any Intellectual Developments related to Employer's trade secrets and/or Confidential Information described by Employee in a patent, service mark, trademark, or copyright application, disclosed by Employee in any manner to a third person, or created by Employee or Employee's affiliates or any person with whom Employee has any business, financial or confidential relationship, within one (1) year after cessation of Employee's employment with Employer for any reason, was conceived or made by Employee during Employee's employment with Employer and is therefore the sole property of Employer or its designees.

10. **Information and Testimony**: For a period of time up to four years from Employee's last date of employment with Employer, Employee shall, without expense to Employee, give such true information and testimony at reasonable times and places upon prior notice, under oath if

requested, as may be requested by Employer or its designees relative to any Intellectual Development described in Section 7 above.

11. **Restrictive Covenant**: Because Employee will be provided with proprietary, confidential, and trade secret information, Employee shall not, during his employment:

    a. enter into, own, manage, operate, control, be employed with, or engage, as an employee, associate, officer, director, shareholder, partner or in any other capacity, on behalf of any association, enterprise, company, or firm that provides services or products in competition with Employer;

    b. directly or indirectly solicit or attempt to solicit the business of any client or customer or active customer prospect of Employer or any of its Affiliates for his own benefit or that of any third person or organization; and

    c. directly or indirectly induce any employee or contractor of Employer or any of its Affiliates to leave his or his employment or independent contract with Employer or any of its Affiliates.

12. **Non-Disparagement**: Employee agrees that at any time during his employment with Employer and at any time thereafter, Employee shall not, except in the good faith commission of his duties and responsibilities, make, or cause or assist any other person to make, any statement or other communication that impugns or attacks, or is otherwise critical to the reputation, business or character of Employer or any of its officers, directors, members, managers, employees, products or services.

13. **Non-Competition and Non-Solicitation of Business/Customers**: In order to protect Company's trade secrets and to the extent permissible under applicable law, including the satisfaction of any applicable compensation requirements, and in exchange for the termination payment described in Section 16 below, for a period of twelve (12) months following termination of Employee's employment, for any reason, Employee agrees not to (a) enter into or engage in any business which competes with Company or any of its subsidiaries or Affiliates ("**Company Group**") within the States of Pennsylvania, Colorado, Texas, Louisiana, and any other state in which Company Group is operating any of its businesses as of Employee's termination date ("**Restricted Territory**"); (b) promote, manage or assist, financially or otherwise, any person, firm, association, partnership, corporation or other entity engaged in any business which competes with or is engaged in the same business as the Company Group within the Restricted Territory; (c) solicit any known customers, business, assets, investments or patronage (or customer, business, asset, investment or patronage prospects) for, or sell, any products or services in competition with or for any business that competes with the Company Group within the Restricted Territory; or (d) divert, entice or otherwise take away any known business, assets or investments or patronage (or customer, business, asset, investment or patronage prospects) of Company Group within the Restricted Territory. As used herein, "any business which competes with the Company Group" refers to a business which derives, or plans or intends to derive, at least ten percent (10%) of its EBITDA from the same line or lines of business which the Company Group conducts in the Restricted Territory as of Employee's termination date or which the Company Group plans or intends to conduct as of Employee's termination date. For purposes of this Section 13

Employee will be in violation of the non-compete provision set forth herein if Employee engages in any or all of the activities set forth herein directly as an individual on Employee's own account or indirectly as a partner, joint venture, employee, agent, salesperson, consultant, officers and/or director of any firm, association, partnership, corporation or other entity or as a shareholder of any corporation (or owner of any other type of equity interest in any other entity) in which Employee or Employee's spouse, minor child, or parent sharing the same household as Employee owns, directly or indirectly, individually or in the aggregate, more than 1% of the outstanding stock or other equity interests or rights to distributions. If it is judicially determined or by consent of Employee that Employee has violated this Section 13 and Company obtains an order, injunction or other equitable relief, then the period applicable to each obligation that Employee has been determined to have violated will be automatically extended by a period of time equal in length to the period during which such violation occurred. Employee agrees and acknowledges that the covenants set forth in this Section 13 are for the protection of Company's Confidential Information and trade secrets as addressed above in Section 6 and that it is no broader than is reasonably necessary to protect Company's legitimate interest in protecting trade secrets.

14. **Reasonableness of Restraints, Irreparable Harm**: Employee acknowledges that: (a) the agreements and covenants contained herein are reasonably necessary to protect the goodwill, Confidential Information, Intellectual Developments, trade secrets, and other business interests of Employer; (b) any breach of the covenants contained herein will cause Employer immediate irreparable harm for which injunctive relief would be necessary; (c) the covenants contained herein are essential and material elements of this Agreement and Employer would not have entered into this Agreement or permitted Employee to obtain employment or remain employed without those covenants being included in this Agreement; (d) Employee has had the opportunity to consult with and be advised by legal counsel concerning the reasonableness and propriety of the covenants contained herein; and (e) in the event of any violation or attempted violation of the covenants contained herein, Employer shall be entitled to a temporary restraining order, temporary or permanent injunctions, and other injunctive relief, without any showing of irreparable harm or damage or any need to post a bond, in addition to any other rights or remedies which may then be available to Employer. In addition to, but not instead of, any other legal or equitable remedies available to Employer, Employee hereby agrees to reimburse Employer for reasonable attorneys' fees and costs incurred by Employer in the event Employer is successful in showing a violation or attempted violation of this Agreement as determined by a court of competent jurisdiction.

15. **No Existing Obligations**: Employee represents that Employee: (a) is not subject to a confidentiality, trade secret, conflict of interest, or non-competition agreement with any former employer, contractor or third party which would affect Employee's ability to enter into this Agreement with the Company or which may be breached by Employee's entry into this Agreement or employment with the Company; and (b) has no continuing obligations to any former employer, contractor or third party with respect to the ownership or assignment of any proprietary rights, including, but not limited to, inventions, ideas, copyrights, trade secrets or patents, including any such rights in information, or creations or materials Employee conceived or made, in whole or in part that will impact Employee's services for Employer. Employee understands that any such agreement or obligation, as well as any trade secret and other property laws, may restrict Employee from using any secret or proprietary information that belongs to any former employer, contractor or third party, either for Employee's own benefit or for anyone else's benefit, including Employer. Employee also understands that Employee, or anyone else who uses or benefits from a third party's proprietary information, may be liable to that third party; therefore, Employee agrees not to use any confidential, trade secret, or proprietary information that belongs to any former employer, contractor, or third party during the term of employment, either for Employee's own benefit or to benefit Employer or any of its clients, customers, or affiliates.

16. **Termination of Employment and Severance Payment**: Notwithstanding the at-will nature of Employee's employment, if Employee's employment is terminated by Company without "Cause" or by Employee for "Good Reason", in each case, as defined below, in addition to the (a) payment of Employee's current Base Compensation per Section 5(a), (b) payment for any unused, accrued PTO as of Employee's termination date per Section 5(d), and (c) reimbursement of any outstanding, reasonable business expenses incurred by Employee through the termination date, Employee will be eligible to receive an amount equal to (d) twenty-four (24) months of Employee's current Base Compensation as of the date of

termination, plus (e) a pro-rated amount of Employee's Annual Target Bonus at the rate of ninety-five percent (95%) for the calendar year in which Employee's employment is so terminated (based on the number of days Employee was employed by Company during such calendar year), plus (f) any annual bonus for the year prior to the year in which the termination occurs that is earned but remains unpaid, plus (g) monthly payment of COBRA premiums for Employee and his family, to the extent such coverage is elected and in line with Employee's then current coverage election, for twelve (12) months following Employee's termination date. The amounts described in (d) and (e) shall be payable fifty percent (50%) on the six (6)-month anniversary of Employee's termination date and fifty percent (50%) on the twelve (12)- month anniversary of Employee's termination date and the amount described in (f) shall be payable when such bonuses are normally paid (clauses (d), (e), (f) and (g) collectively, the "**Severance Payment**"); provided, that (i) Employee timely executes a release agreement in a form satisfactory to the Company within the consideration period, which shall be no less than 45 days following such termination of employment and (ii) Employee does not revoke such execution or signature within any revocation period. For the avoidance of doubt, the treatment of any outstanding equity awards granted to Employee upon the termination of Employee's employment with the Company shall be subject to the terms and conditions set forth in the applicable equity award agreement and equity incentive plan. It is expressly understood that, in the event Employee breaches any of the covenants set forth in Sections 6 through 15, the Company's obligations with respect to the Severance Payment shall cease and Employee shall immediately repay to the Company the full amount of any Severance Payments paid by the Company to Employee prior to the date of such breach. "**Cause**" means any of the following: (i) other than as a result of a death or disability, Employee's willful failure to perform Employee's duties; (ii) Employee's willful engagement in misconduct which is injurious to the Company or any of its subsidiaries or Affiliates, monetarily or otherwise; (iii) Employee's conviction of a crime (including a nolo contendere plea) involving, in the good faith of the Company, fraud, dishonesty or moral turpitude; (iv) the negligent performance of Employee's duties; (v) Employee's breach of any covenant set forth in this Agreement; or (vi) Employee's breach of any material Company policy. For the avoidance of doubt, Employee will be considered to have been terminated for "Cause" if the Company determines in good faith prior to a Change in Control that Employee engaged in an act constituting "Cause" even after a resignation by Employee. "**Good Reason**" means (I) a relocation of the Employee's principal place of employment by more than thirty (30) miles beyond Employee's principal place of employment in Houston, Texas once such office is established, or (II) within the two-year period following a Change of Control, (x) a reduction in Employee's Base Compensation or Annual Target Bonus; or (y) a material, adverse change in Employee's authority, duties or responsibilities (other than temporarily while the Participant is physically or mentally incapacitated); provided, however, Employee shall not be considered to have terminated Employee's employment for "Good Reason" unless, within sixty (60) days following the occurrence of the event giving rise to "Good Reason," Employee gives the Company written notice of the existence of such event, the Company does not remedy such event within sixty (60) days of receiving such notice and Employee terminates Employee's employment within thirty (30) days of the end of the Company's cure period. "**Change of Control**" shall have the meaning set forth in Section 12 of the BKV Corporation 2024 Equity and Incentive Compensation Plan.

17. **<u>Internal Revenue Code Section 409A Compliance</u>**: Both Employee and the Company intend that all compensation or benefits paid under this Agreement are, to the maximum extent possible, exempt from Internal Revenue Code Section 409A and the regulations and guidance promulgated thereunder (collectively "**Section 409A**") or, to the extent not extent, comply with Section 409A, and, accordingly, to the maximum extent permitted, this Agreement shall be interpreted in accordance with such intention. Notwithstanding any other provision of this Agreement to the contrary, if any amount to be paid to Employee as a result of the termination of Employee's employment pursuant to this Agreement is "deferred compensation" subject to Section 409A, and if Employee is a "specified employee" (as defined under Section 409A) as of the date of Employee's termination of employment

hereunder, then, to the extent necessary to avoid the imposition of excise taxes or other penalties under Section 409A, the payment of benefits, if any, scheduled to be paid by the Company to Employee hereunder during the first six (6) month period following the date of a termination of employment hereunder shall not be paid until the date which is the first business day following the six-month anniversary of the termination of Employee's employment for any reason other than death. Any deferred compensation payments delayed in accordance with the terms of this Section 17 shall be paid in a lump sum when paid. In addition, both Employee and the Company agree to cooperate fully with one another to attempt to ensure compliance with Section 409A, including, without limitation, adopting amendments to arrangements subject to Section 409A and operating such arrangements in compliance with Section 409A; provided, however, nothing in this Section 17 shall require Employee to reduce Employee's compensation; provided, further, however, nothing in this Agreement shall constitute an agreement to indemnify, gross up or otherwise make Employee whole for any taxes imposed under Section 409A. Company does not make any representation as to whether any benefits, payments, or reimbursements under this Agreement satisfy the requirements of Section 409A or any exemption thereto.

18. **<u>Right to Offset</u>**: Employee acknowledges and understands that Company shall have the right to offset any amounts owed by Employee to Company against any amounts payable by Company to Employee under this Agreement.

19. **<u>Assignment</u>**: This Agreement may be assigned by Employer to any affiliated or successor employer without the consent of Employee, and so long as the affiliate or successor accepts the assignment, this Agreement will continue to be binding upon Employee. This Agreement may not be assigned by Employee.

20. **<u>Severability</u>**: Each section of this Agreement shall be and remain separate from and independent of, and severable from, all and any other sections herein except where otherwise indicated by the context of the Agreement. To the extent any portion of this Agreement, or any portion of any provision of this Agreement is held to be invalid or unenforceable, it is the Parties' express intent it shall be construed by severing, limiting and reducing it so as to be enforceable to the extent compatible with applicable law. All remaining provisions, and/or portions thereof, shall remain in full force and effect.

21. **<u>Modification</u>**: Any modification of this Agreement or any additional obligation assumed by either Party in connection with this Agreement shall be in writing and signed by each Party.

22. **<u>No Waiver</u>**: The failure of either Party to this Agreement to insist upon the performance of any terms and conditions or the waiver of any breach of any terms and conditions of this Agreement shall not be construed as thereafter waiving such terms and conditions, but the same shall continue to remain in full force and effect.

23. **<u>Complete Agreement</u>**: This Agreement contains the complete agreement concerning the employment agreement between the Parties and supersedes any and all prior understandings and agreements between the Parties concerning the subject matter hereof. The Parties stipulate that neither has made any representation with respect to the subject matter of this Agreement except such representations as are specifically set forth in this Agreement.

24. **<u>Interpretation of Agreement</u>**: The validity, interpretation, construction, and performance of this Agreement shall be governed by the laws of the State of Texas, without regard to its conflict of law provisions. This Agreement shall be interpreted with all necessary changes in gender and in number as the context may require and shall inure to the benefit of and be binding upon the respective successors and assigns of the parties hereto.

25. **<u>Survival</u>**: The terms and provisions of this Agreement which, by their express or implicit terms, are intended to survive the cancellation, termination, or expiration of this Agreement and be enforceable to the extent necessary to carry out the rights or obligations of either Party under this Agreement.

26. **<u>Resolution of Disputes</u>**: The Parties consent and agree that, except as set forth in this Section

26, any action or proceeding between them arising from this Agreement shall be exclusively referred to binding arbitration in Houston, Texas in accordance with the Employment Arbitration Rules and Mediation Procedures of the American Arbitration Association ("**AAA**") before a single arbitrator mutually selected by Employer and Employee. The decision of the arbitrator shall be final, non- appealable and binding upon the parties and may be enforced in any court having jurisdiction thereof. The AAA Rules regarding discovery shall apply to arbitration under this Agreement. The Arbitrator selected according to this Agreement shall decide all discovery disputes. The parties shall split the administrative cost of arbitration equally and each Party shall be responsible for the payment of its own respective legal fees. CLAIMS WHERE MANDATORY ARBITRATION IS PROHIBITED BY A VALID NON- PREEMPTED LAW ARE EXPLICITLY EXCLUDED FROM THIS ARBITRATION PROVISION. CLAIMS IN ARBITRATION SHALL BE FILED AND MAINTAINED ONLY ON AN INDIVIDUAL BASIS. EMPLOYEE MAY NOT FILE OR MAINTAIN ANY CLAIM IN ARBITRATION ON BEHALF OF OTHISS, COLLECTIVELY OR OTHISWISE, OR AS A NAMED PLAINTIFF/CLAIMANT OR MEMBER IN ANY PURPORTED CLASS, COLLECTIVE, OR REPRESENTATIVE PROCEEDING. THE ARBITRATOR MAY NOT CONSOLIDATE MORE THAN ONE PARTY'S CLAIMS, AND MAY NOT OTHISWISE PRESIDE OVER ANY FORM OF A COLLECTIVE, CLASS, OR REPRESENTATIVE ARBITRATION PROCEEDING. Notwithstanding the foregoing, any claim related to or arising under this Agreement shall be asserted exclusively in the state or federal courts of the State of Texas, and Employee hereby expressly consents to the jurisdiction thereof.

27. **Notice**: Notice shall be provided in writing via certified mail (return receipt requested), overnight courier or personal delivery to the address set forth below:

If to Employer:	**If to Employee:**
[***]	[***]
[***]	[***]
[***]	[***]

[Signature Page to Follow]

IN WITNESS WHISEOF, the Parties have executed this Employment Agreement on the date or dates set forth below.

/s/ Christopher P. Kalnin	/s/ Dilanka Seimon
Christopher P. Kalnin,	Dilanka Seimon
CEO BKV Corporation	
Date: 4/1/2025	Date: 4/1/2025

EXHIBIT 1

Exempt
Full-time Position

EXHIBIT 2

Summary of Benefits Currently Offered by BKV Corporation ("Employer")

Exhibit 21.1

SIGNIFICANT SUBSIDIARIES OF BKV CORPORATION

As of December 31, 2025

The following subsidiaries are deemed “significant subsidiaries” pursuant to Item 601(b)(21) of Regulation S-K:

Name	**State or Other Jurisdiction of Incorporation or Organization**
BKV Barnett, LLC	Delaware
BKV Barnett II, LLC	Texas
BKV-BPP Power, LLC	Delaware
BKV Chelsea, LLC	Delaware
BKV dCarbon Barnett Zero, LLC	Delaware
BKV dCarbon High West, LLC	Delaware
BKV dCarbon Las Tiendas, LLC	Delaware
BKV dCarbon Temple, LLC	Delaware
BKV dCarbon Ventures, LLC	Delaware
BKV Midstream, LLC	Delaware
BKV North Texas, LLC	Delaware
BKV Operating, LLC	Delaware
BKV Upstream Midstream, LLC	Delaware
BKV-BPP Cotton Cove, LLC	Delaware
BKVerde, LLC	Delaware
High West Sequestration, LLC	Louisiana
Temple Generation I, LLC	Delaware
Temple Generation II, LLC	Delaware

Note: Pursuant to Item 601(b)(21) of Regulation S-K, the registrant has omitted the names of subsidiaries, which considered in the aggregate as a single subsidiary, would not constitute a “significant subsidiary” (as defined under Rule 1-02(w) of Regulation S-X) as of the date set forth above.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No.333-282383) of BKV Corporation of our report dated March 6, 2026 relating to the financial statements which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas

March 6, 2026

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
555 17TH STREET SUITE 985 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Ryder Scott Company, L.P. hereby consents to the references to its firm in the form and context in which they appear in this Annual Report on Form 10-K filed by BKV Corporation (the “Annual Report”). Ryder Scott Company, L.P. hereby further consents to the use and incorporation by reference of information from its reports regarding those quantities estimated by Ryder Scott of proved reserves of BKV Corporation and its subsidiaries, the future net revenues from those reserves and their present value for the years ended December 31, 2025, 2024 and 2023, and to the inclusion of its summary reports dated January 6, 2026 and January 27, 2026 as exhibits to the Annual Report. We further consent to the incorporation by reference thereof into BKV Corporation’s Registration Statements on Form S-3 (File Nos. 333-290676 and 333-292408) and on Form S-8 (File No. 333-282383, effective September 27, 2024).

/s/ Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Denver, Colorado
February 9, 2026

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 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

I, Christopher P. Kalnin, certify that:

1. I have reviewed this Annual Report on Form 10-K of BKV Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 6, 2026

/s/ Christopher P. Kalnin
Christopher P. Kalnin
Chief Executive Officer
Principal Executive Officer

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

I, David R. Tameron, certify that:

1. I have reviewed this Annual Report on Form 10-K of BKV Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 6, 2026

/s/ David R. Tameron
David R. Tameron
Chief Financial Officer
Principal Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, Christopher P. Kalnin, the Chief Executive Officer of BKV Corporation (the "Company"), hereby certify, that, to the best of my knowledge:

(1) The Annual Report on Form 10-K of the Company for the period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 6, 2026

/s/ Christopher P. Kalnin
Christopher P. Kalnin
Chief Executive Officer
Principal Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, David R. Tameron, the Chief Financial Officer of BKV Corporation (the "Company"), hereby certify, that, to the best of my knowledge:

(1) The Annual Report on Form 10-K of the Company for the period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 6, 2026

/s/ David R. Tameron
David R. Tameron
Chief Financial Officer
Principal Financial Officer

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2025

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.

TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
555 17TH STREET SUITE 985 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 6, 2026

BKV Corporation
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 reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) as of December 31, 2025. The subject properties are located in the states of Pennsylvania and 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 January 6, 2026 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 evaluated by Ryder Scott account for 100 percent of BKV's total net proved liquid hydrocarbon and gas reserves as of December 31, 2025.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2025 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 required by SEC regulations. 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
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corporation
As of December 31, 2025

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	1,600	163	2,118	3,881
Plant Products – Mbbl	162,684	20,427	75,545	258,656
Gas – MMcf	2,913,523	184,341	1,247,900	4,345,764
MMCFE	3,899,227	307,881	1,713,878	5,920,986
Income Data ($M)				
Future Gross Revenue	$10,681,849	$852,697	$4,780,359	$16,314,905
Deductions	6,501,795	495,081	2,663,777	9,660,653
Future Net Income (FNI)	$ 4,180,054	$357,617	$2,116,582	$ 6,654,252
Discounted FNI @ 10%	$ 2,151,656	$111,645	$ 524,708	$ 2,788,009

Values may not sum to total due to rounding

PERCENTAGE OF PROVED RESERVES PER HYDROCARBON PHASE (gas equivalent basis)

OPERATED Operating Region	Estimated Total Proved Reserves (MMCFE)	% Natural Gas	% Natural Gas Liquids	% Oil	Average Annual PDP Decline Five Year	Average Annual PDP Decline Ten Year
Barnett	5,264,494	70.4%	29.2%	0.4%	8%	7%
NEPA	531,943	100.0%	0.0%	0.0%	11%	9%
Total	5,796,437	73.1%	26.5%	0.4%	9%	7%

December 31, 2025

NON-OPERATED Operating Region	Estimated Total Proved Reserves (MMCFE)	% Natural Gas	% Natural Gas Liquids	% Oil	Average Annual PDP Decline Five Year	Average Annual PDP Decline Ten Year
Barnett	55,487	68.9%	30.7%	0.4%	9%	8%
NEPA	69,062	100.0%	0.0%	0.0%	13%	11%
Total	124,549	86.2%	13.7%	0.1%	9%	8%

December 31, 2025

TOTAL COMPANY	December 31, 2025					
Operating Region	Estimated Total Proved Reserves (MMCFE)	% Natural Gas	% Natural Gas Liquids	% Oil	Average Annual PDP Decline	
					Five Year	Ten Year
Barnett	5,319,981	70.4%	29.2%	0.4%	8%	7%
NEPA	601,005	100.0%	0.0%	0.0%	11%	9%
Total	5,920,986	73.4%	26.2%	0.4%	9%	7%

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 net reserves volumes are also shown herein on an equivalent unit basis wherein hydrocarbon liquid is converted to natural gas equivalent using a factor of 1 barrel of liquid per 6,000 cubic feet of natural gas equivalent. MMCFE means million cubic feet of natural gas equivalent.

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 (including the Pennsylvania Impact Fee), 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 72 percent and liquid hydrocarbon reserves account for the remaining 28 percent of total future gross revenue from proved 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.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2025 Total Proved
9	$2,975,334
12	$2,470,980
15	$2,102,501
20	$1,672,238

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 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 developed non-producing reserves included herein consist of the shut-in and behind pipe status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved 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 only the proved 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 proved reserves included herein were estimated using deterministic methods. 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."

Proved 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 reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved 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 proved 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. In general, 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 2025, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. For certain early-life cases, where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a sole basis for the estimates was considered to be inappropriate, producing reserves were guided by analogy to older, more established wells. The data utilized in our analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories 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 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 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 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 taxes (including the Pennsylvania Impact Fee), production taxes, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations,

adjustments or differentials to product prices, geological structure and isochore maps, 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 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 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. If no production decline trend has been established, future decline trends were based on analogy to older, more established wells.

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, 2025. 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 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 Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$65.34/Bbl	$58.36/Bbl
	NGLs	WTI Cushing	$65.34/Bbl	$17.31/Bbl
	Gas	Henry Hub	$3.387/MMBTU	$2.81/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 certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2025. 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, 2025, 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.

BKV makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, BKV has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the

incorporation by reference in the registration statements on Form S-8 of BKV, of the references to our name, as well as to the references to our third-party report for BKV, which appears in the December 31, 2025 annual report on Form 10-K of BKV. Our written 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

/s/ Stephen E. Gardner

[SEAL]

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/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, as well as for coordinating and supervising the evaluations of staff and consulting engineers of the company. Mr. Gardner is also a member of Ryder Scott's Board of Directors. 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 (SPE) and a former director of the Society of Petroleum Evaluation Engineers (SPEE). He currently serves as an officer for SPEE 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 2025 continuing education hours, Mr. Gardner attended multiple technical conferences, including the SPEE Annual Meeting and the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, geothermal energy, reserves definitions and guidelines, SEC comment letter trends, ethics, and others. Mr. Gardner attended the 2025 Geothermal Rising Conference, where he presented a technical paper on geothermal resource classifications. In addition, Mr. Gardner participated in various local technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, M&A trends, regulatory issues, enhanced geothermal systems, and more.

Based on his educational background, professional training and approximately 20 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.

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 CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters
(NYMEX Alternate Pricing Scheme)

As of

December 31, 2025

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
555 17TH STREET SUITE 985 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 27, 2026

BKV Corporation
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 reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) as of December 31, 2025. The subject properties are located in the states of Pennsylvania and 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 27, 2026 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, 2025.

The properties evaluated by Ryder Scott account for 100 percent of BKV's total net proved liquid hydrocarbon and gas reserves as of December 31, 2025.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2025 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 Corporation
As of December 31, 2025

	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	1,597	163	2,086	3,846
Plant Products – Mbbl	163,078	20,426	74,843	258,347
Gas – MMcf	2,972,440	184,347	1,243,920	4,400,707
MMCFE	3,960,490	307,881	1,705,494	5,973,865

Income Data ($M)

		Proved		
Future Gross Revenue	$11,277,772	$862,978	$4,922,070	$17,062,821
Deductions	6,679,619	494,976	2,649,250	9,823,845
Future Net Income (FNI)	$ 4,598,153	$368,002	$2,272,821	$ 7,238,975
Discounted FNI @ 10%	$ 2,364,595	$117,669	$ 599,957	$ 3,082,221

Values may not sum to total due to rounding

PERCENTAGE OF PROVED RESERVES PER HYDROCARBON PHASE (gas equivalent basis)

OPERATED	December 31, 2025					
Operating Region	Estimated Total Proved Reserves (MMCFE)	% Natural Gas	% Natural Gas Liquids	% Oil	Average Annual PDP Decline Five Year	Average Annual PDP Decline Ten Year
Barnett	5,309,381	70.7%	28.9%	0.4%	8%	7%
NEPA	539,130	100.0%	0.0%	0.0%	11%	9%
Total	5,848,511	73.4%	26.2%	0.4%	9%	7%

NON-OPERATED	December 31, 2025					
Operating Region	Estimated Total Proved Reserves (MMCFE)	% Natural Gas	% Natural Gas Liquids	% Oil	Average Annual PDP Decline Five Year	Average Annual PDP Decline Ten Year
Barnett	56,277	69.1%	30.5%	0.4%	9%	8%
NEPA	69,077	100.0%	0.0%	0.0%	13%	11%
Total	125,354	86.1%	13.7%	0.2%	9%	8%

TOTAL COMPANY	December 31, 2025					
Operating Region	Estimated Total Proved Reserves (MMCFE)	% Natural Gas	% Natural Gas Liquids	% Oil	Average Annual PDP Decline	
					Five Year	Ten Year
Barnett	5,365,658	70.7%	28.9%	0.4%	8%	7%
NEPA	608,207	100.0%	0.0%	0.0%	11%	9%
Total	5,973,865	73.7%	25.9%	0.4%	9%	7%

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 net reserves volumes are also shown herein on an equivalent unit basis wherein hydrocarbon liquid is converted to natural gas equivalent using a factor of 1 barrel of liquid per 6,000 cubic feet of natural gas equivalent. MMCFE means million cubic feet of natural gas equivalent.

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 (including the Pennsylvania Impact Fee), 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 76 percent and liquid hydrocarbon reserves account for the remaining 24 percent of total future gross revenue from proved 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, 2025
Discount Rate Percent	Total Proved
9	$3,284,033
12	$2,740,433
15	$2,342,635
20	$1,876,948

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 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 developed non-producing reserves included herein consist of the shut-in and behind pipe status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved 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 only the proved 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 proved reserves included herein were estimated using deterministic methods. 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."

Proved 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 reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved 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 current cost assumptions, may differ from the quantities of reserves which would be estimated using the price parameters 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 proved 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. In general, 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 2025, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. For certain early-life cases, where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a sole basis for the estimates was considered to be inappropriate, producing reserves were guided by analogy to older, more established wells. The data utilized in our analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories 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 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 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 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 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 taxes (including the Pennsylvania Impact Fee), production taxes, development costs, development plans, abandonment costs after salvage, product price assumptions, adjustments or differentials to product prices, geological structure and isochore maps, 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 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 reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations and are 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. If no production decline trend has been established, future decline trends were based on analogy to older, more established wells.

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, 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.

At BKV's request, we furnished the NYMEX Futures Strip prices in effect as of December 31, 2025, that were used as the average benchmark prices in this 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 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		
United States	WTI - Cushing	Henry Hub	Oil/Cond	Plant Products	Gas
Year	$/Bbl	$/MMBtu	$/Bbl	$/Bbl	$/Mcf
2026	$57.05	$3.63	$49.91	$14.45	$3.05
2027	$57.31	$3.88	$50.10	$14.52	$3.30
2028	$58.57	$3.71	$51.26	$14.95	$3.13
2029	$59.86	$3.61	$52.56	$15.42	$3.03
2030	$60.77	$3.61	$53.84	$15.77	$3.04
2031	$61.30	$3.48	$54.05	$15.79	$3.04
2032	$61.48	$3.33	$53.97	$15.78	$3.04
2033	$61.43	$3.23	$53.94	$15.78	$3.04
2034	$61.11	$3.34	$53.93	$15.78	$3.04
2035	$60.53	$3.42	$53.93	$15.77	$3.04
2036	$59.89	$3.51	$53.92	$15.77	$3.04
2037	$59.89	$3.42	$53.92	$15.77	$3.04
2038+	$59.89	$3.36	$53.92	$15.77	$3.04
Total Future Average Prices			$53.20	$15.54	$3.06

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 certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31,

2025. 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.

BKV makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, BKV has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of BKV, of the references to our name, as well as to the references to our third-party report for BKV, which appears in the December 31, 2025 annual report on Form 10-K of BKV. Our written 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

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720 [SEAL]
Managing Senior Vice President

SEG (DRO)/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, as well as for coordinating and supervising the evaluations of staff and consulting engineers of the company. Mr. Gardner is also a member of Ryder Scott's Board of Directors. 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 (SPE) and a former director of the Society of Petroleum Evaluation Engineers (SPEE). He currently serves as an officer for SPEE 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 2025 continuing education hours, Mr. Gardner attended multiple technical conferences, including the SPEE Annual Meeting and the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, geothermal energy, reserves definitions and guidelines, SEC comment letter trends, ethics, and others. Mr. Gardner attended the 2025 Geothermal Rising Conference, where he presented a technical paper on geothermal resource classifications. In addition, Mr. Gardner participated in various local technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, M&A trends, regulatory issues, enhanced geothermal systems, and more.

Based on his educational background, professional training and approximately 20 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.

<u>RESERVES (SEC DEFINITIONS)</u>

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.*

<u>Note to paragraph (a)(26):</u> 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.

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.