RANGE RESOURCES®

2022 ANNUAL REPORT

FELLOW SHAREHOLDERS

We are pleased to report that Range met or exceeded our key corporate objectives in 2022, leading to a record year in nearly every metric. These accomplishments are a testament to steady progress on our stated mission to realize the value of Range's world-class assets and consistently deliver shareholder returns over our multi-decade core inventory life.

We successfully managed a bullish commodity market, generating record GAAP cash flow from operations of $1.9 billion in 2022, and materially strengthening the Company's financial foundation. As highlighted in last year's shareholder letter, our capital allocation strategy and priority for the use of organic cash flow remains the same: maintenance capex to fully utilize infrastructure and maximize margin; debt reduction toward target levels; return of capital to shareholders via dividends and stock repurchases; and, lastly, growth capex only when appropriate. Our 2022 results provide a great showcase of these priorities in practice.

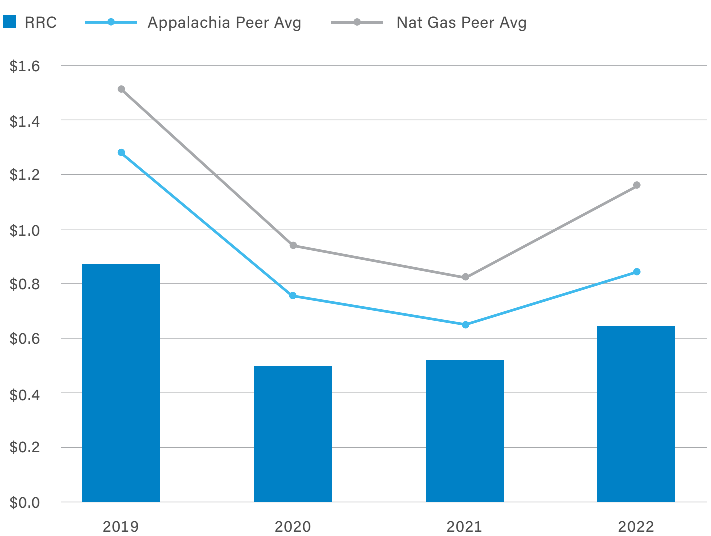
Maintaining Production & Operational Success

Range safely, responsibly, and efficiently delivered on the 2022 capital plan, producing an average of 2,121 Mmcfe per day during the year by investing $491 million of all-in capital. Total capital expenditures to maintain production, our first in priority of capital allocation, represented approximately 25 percent of annual cash flow in 2022, a record low for Range and among the best in the industry. As a result of the outstanding work from the Range team, we remain the most efficient natural gas producer in the country, as measured by maintenance capital requirements per unit of production. Range's 2022 results equate to total capital spending of $0.64 per mcfe produced, which was the lowest among natural gas producers during the year, and it is our expectation to execute one of, if not the most, capital-efficient programs again in 2023.

Our low capital requirements are the result of Range's class-leading drilling and completion costs, coupled with our shallow base decline and large core inventory. Together, these result in a peer-leading production maintenance program, providing Range a solid foundation to consistently generate significant free cash flow and returns to shareholders.

Range pioneered the Marcellus Shale more than 18 years ago, and since then, the Company has accumulated a large contiguous acreage position in Southwestern Pennsylvania. At year-end 2022, Range had roughly a half million net acres of core leasehold in Pennsylvania, with infrastructure capacity to deliver production across much of the United States and globally. Range's work in growing the Marcellus

CAPITAL EFFICIENCY - CAPEX PER MCFE



into the United States' most prolific natural gas field has led to increased efficiencies, improved recoveries, and advancement of environmental best practices.

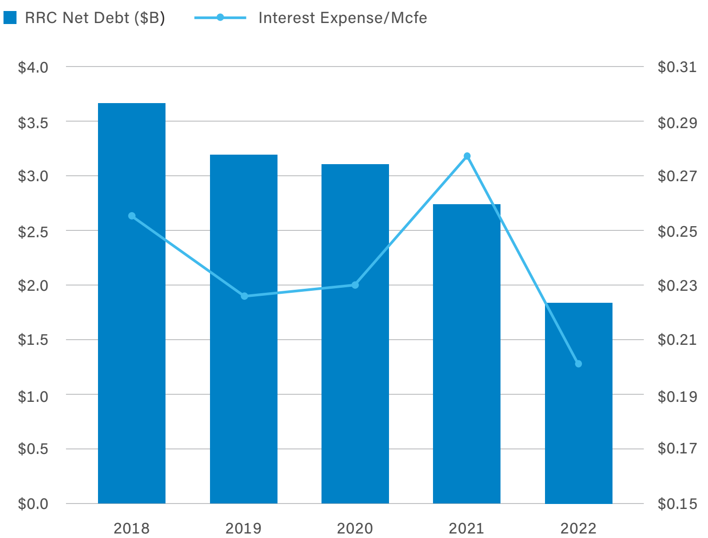
We have maintained a deep natural gas and natural gas liquids (NGLs) drilling inventory. This unrivaled opportunity affords us product diversity and flexibility to maximize sustainable returns. Not only does our inventory provide us with a lengthy development time horizon, but its consolidated nature allows us to realize capital and operational efficiencies like long lateral development, efficient water handling solutions, reduced trucking, and utilizing existing surface locations and facilities.

Range also achieved advancements in our safety performance during 2022. Through collaborative efforts with our employees and contractors, Range achieved a 50 percent reduction in our OSHA incident rate and reached a record low for days away or restricted duty, making 2022 one of the best safety performances in Company history. Safety can never be taken for granted, but we are proud of this accomplishment.

Financial Foundation and Debt Reduction

To increase our financial resiliency, Range has reduced absolute debt each year since 2018. While debt reduction is typically not categorized by the market as return of capital, it carries the benefit of positively shifting the debt-to-equity capital structure ratio and lowering corporate cash costs. Interest expense has materially declined over the past few years, giving way to a lower corporate break-even commodity price, and added free cash flow.

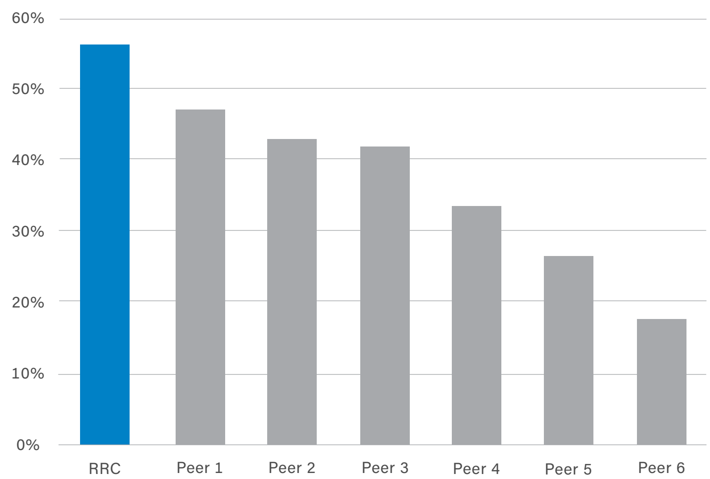
RANGE NET DEBT & INTEREST EXPENSE/MCFE



In the spring of 2021, Range set a target to reduce debt by more than $2 billion by the end of 2023. Today, we have achieved 90 percent of that target and have done so organically. It has been a successful repositioning of our balance sheet within a short period of time, and clears the path for prudent and optimal capital allocation, including additional returns of capital to shareholders in the years ahead. Range reduced net debt by more than $860 million in 2022, representing approximately half of annual cash flow. Debt reduction was Range's largest capital allocation category during the year and set a record for the Company. At year-end, Range's net debt was approximately $1.87 billion, nearing our targeted net debt level of $1.0 to $1.5 billion. The Company's targeted debt balance is consistent with balance sheet targets described in last year's proxy, and we believe it will provide a financial foundation for Range to be both resilient and opportunistic through commodity price cycles that are inevitable in our business.

We were able to capture much of the opportunity for free cash flow and debt reduction arising from better commodity prices in 2022 with a deliberate, fit-for-purpose hedging program. For two consecutive years, Range's hedge program allowed the Company to retain more pricing upside on a per Mcfe basis than our natural gas peers.

REALIZED PERCENTAGE OF TOTAL FCF POTENTIAL[a] 2021 – 2022



(a) FCF Potential equals company-stated FCF plus cash settlements for derivatives. Peers include AR, CHK, CNX, CRK, EQT, and SWN.

Our hedging strategy is not aimed at picking market tops and bottoms, but at supporting durable free cash flow through the price cycles while retaining exposure to what we expect will be improving long-term natural gas and NGL fundamentals. Looking ahead, we believe the hedge program is once again positioned for success in 2023 and 2024, and we will continue to structure and scale our hedge portfolio to capture value for shareholders while prudently covering our fixed costs and capital commitments.

Returns of Capital to Shareholders

During 2022, Range's Board of Directors approved the reinstatement of the Company's regular quarterly cash dividend, and payments started in the second half of 2022 at an annual dividend rate of $0.32 per share of the Company's common stock ($0.08 per quarter). Range's dividend is a two-fold commitment: it is a commitment to tangible shareholder returns from business earnings, and it is a commitment to maintain a balance sheet that can sustain these shareholder returns through price cycles.

In addition, Range's share repurchase program was increased to $1.5 billion from the original 2019 authorization. During the year, Range purchased 14 million shares for $400 million, and since initiation, Range has repurchased a total of $430 million in stock, reducing share count by 24 million shares or nearly 10 percent. We view repurchases as a powerful tool and an attractive investment opportunity, given the significant gap between what we see as the value of Range's inventory and production versus current share price. A portion of the value of this inventory can be found in our year-end reserves. The after-tax PV10 of our reserves using recent forward pricing equates to over $40 per share net of debt, making share repurchases a compelling investment. For added context, our reserve report includes our proved developed wells and only 367 undeveloped locations out of an estimated 3,000 undrilled core locations we have in the Marcellus. Simply put, we do not believe this significant resource value is reflected in today's market valuation of the Company, presenting Range the opportunity to create meaningful, long-term per-share value for equity holders through our buyback program, which has $1.1 billion of availability remaining.

Total returns of capital to shareholders represented approximately 25 percent of annual cash flow in 2022 via dividends and share repurchases. While our near-term priority remains further strengthening the balance sheet, as debt declines, we have latitude to deploy free cash flow, as evidenced by our repurchase activity in 2022.

Outlook for 2023 and Beyond

We believe that natural gas and NGLs are and will continue to be a vital resource for the United States and the world. As we strive to safely and responsibly produce these commodities, shareholder value creation through the generation of free cash flow and its prudent re-deployment remains our primary focus. Range's all-in capital budget for 2023 is $570 to $615 million, which is projected to allow the Company to maintain production at 2.12 to 2.16 Bcfe per day, while further strengthening the balance sheet toward the $1.0 to $1.5 billion net debt target. We expect all-in maintenance capital to be approximately $0.76 per Mcfe produced during the year, the lowest amongst U.S. natural gas producers, even while adding in-process inventory to provide increased optionality for 2024 and 2025 operational plans in a cost environment in which we and our peers have experienced inflationary pressures. Considering Range's capital efficiency, combined with a peer-leading hedging program and a liquids pricing uplift, the Company maintains the ability to generate free cash flow under relatively low commodity price scenarios, which we believe to be a differentiator for Range.

Growth capex has not recently been a capital allocation priority; however, we see a world that requires access to clean, safe, reliable, and abundant fuel sources produced by ethical and responsible companies. Europe's challenges over the past year are a stark reminder that evolving energy policy must be thoughtful, prioritizing security, affordability, and availability to be successful. Within that framework, we believe Appalachia natural gas and NGLs will play a key role in meeting the world's energy and manufacturing needs. However, pipeline infrastructure investment is needed before it is possible for the industry to meaningfully increase Appalachian supply. That said, we believe Range is positioned for success in whatever infrastructure scenario we find ourselves in the future. As the most capital-efficient operator in the largest natural gas field in the world, we believe Range sits on the low end of the global cost curve for natural gas. Importantly, Range and other Appalachian producers also have advantaged emissions intensity profiles, given the prolific nature of the Marcellus, robust drilling standards, and a focus on operational efficiencies. In the likely future, where additional Appalachian gas transportation infrastructure is available and commodity prices warrant, Range has the inventory, personnel, and balance sheet to allocate capital toward growth when appropriate.

Closing

As the world continues to move towards cleaner, more-efficient fuels, there can be little doubt that American natural gas and NGLs will continue to be the affordable, reliable, and abundant supply that helps power our everyday lives, while also helping billions of others improve their standard of living. We believe Appalachia natural gas and natural gas liquids are positioned to meet that future demand – especially with the development of additional infrastructure. Within Appalachia, Range is leading the way on capital efficiency, emissions intensity, and transparency, which are all core to generating sustainable long-term value for shareholders.

Range is proud of our team, the work we do, and the products we produce. We remain committed to developing these resources responsibly, in cooperation with our communities, as well as to finding new, innovative processes to improve operational and financial performance. We are excited about the opportunity to develop Range's world-class inventory over the coming decades into a growing market for natural gas and natural gas liquids.

In closing, we would like to recognize our employees, vendors, and royalty owners on another successful year. Our collaborative achievements elevated Range to a position of success we are proud of and one we are committed to improving upon. We also want to thank our fellow Directors for their guidance and commitment to long-term value creation for shareholders. Most importantly, we thank our shareholders for your continued support.

GREG G. MAXWELL
CHAIRMAN

JEFFREY L. VENTURA
CHIEF EXECUTIVE OFFICER & PRESIDENT

CORPORATE INFORMATION

BOARD OF DIRECTORS

BRENDA A. CLINE [1, 4, 5]	Chief Financial Officer, Treasurer & Secretary of Kimbell Art Foundation
MARGARET K. DORMAN [1, 5]	Former Executive Vice President, Chief Financial Officer and Treasurer of Smith International, Inc.
JAMES M. FUNK [2, 4, 5]	Former Senior Vice President of Equitable Resources, past President of Equitable Production Co.
STEVE D. GRAY [2, 5]	Founder, past Director and Chief Executive Officer of RSP Permian Inc.
GREG G. MAXWELL [1, 2, 3, 5]	Chairman, Range Resources Corporation, past Executive Vice President, Finance & Chief Financial Officer of Phillips 66
REGINAL W. SPILLER [4, 5]	President and Chief Executive Officer of Azimuth Energy Investments, LLC and former Deputy Assistant Secretary of Oil and Gas at the U.S. Department of Energy
JEFFREY L. VENTURA [3]	Chief Executive Officer & President, Range Resources Corporation

SENIOR MANAGEMENT

JEFFREY L. VENTURA	Chief Executive Officer & President
DENNIS L. DEGNER	Executive Vice President – Chief Operating Officer
MARK S. SCUCCHI	Executive Vice President – Chief Financial Officer
ALAN W. FARQUHARSON	Senior Vice President – Reservoir Engineering & Economics
DORI A. GINN	Senior Vice President – Controller & Principal Accounting Officer
ERIN W. MCDOWELL	Senior Vice President – General Counsel & Corporate Secretary

Board Committee Membership: [1] Audit, [2] Compensation, [3] Dividend, [4] Governance & Nominating, [5] ESG & Safety

FORM 10-K

Additional printed copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request from Investor Relations at our headquarters' address.

Inquiries about the Company should be directed to:

INVESTOR RELATIONS
RANGE RESOURCES CORPORATION
100 THROCKMORTON ST., SUITE 1200
FORT WORTH, TX 76102
817-870-2601
817-869-9100 (FAX)

TRANSFER AGENT

For assistance regarding a change of address or concerning your stock account, please contact:

COMPUTERSHARE, INC.
P.O. BOX 505005
LOUISVILLE, KY 40233-5005
877-581-5548
https://www-us.computershare.com/investor/contact

Use our web site to obtain the latest news releases and SEC filings:
WWW.RANGERESOURCES.COM

In addition to historical information, this report contains forward-looking statements that may vary materially from actual results. Factors that could cause actual results to differ are included in the Company's Form 10-K for the year ended December 31, 2022, which has been filed with the Securities and Exchange Commission.

FORM

10-K

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

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2022
OR

☐ **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: 001-12209

RANGE RESOURCES CORPORATION
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**34-1312571**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200, Fort Worth, Texas	**76102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code **(817) 870-2601**

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

Title of Each Class	Trading Symbol	Name of each exchange on which registered
Common Stock, $.01 par value	RRC	New York Stock Exchange

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

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

Yes ☒ No ☐

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 ☐ No ☒

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 ☒ No ☐

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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	☒	Smaller reporting company	☐
Accelerated filer	☐	Emerging growth company	☐
Non-accelerated filer	☐		

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: ☐

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. ☒

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. ☐

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). ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2022 was $5,979,284,000. This amount is based on the closing price of registrant's common stock on the New York Stock Exchange on that date. Shares of common stock held by executive officers and directors of the registrant are not included in the computation. However, the registrant has made no determination that such individuals are "affiliates" within the meaning of Rule 405 of the Securities Act of 1933.

As of February 20, 2023, there were 240,617,237 shares of Range Resources Corporation common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement to be furnished to stockholders in connection with its 2023 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates, are incorporated by reference in Part II, Item 5 and Part III, Items 10-14 of this report.

RANGE RESOURCES CORPORATION

Unless the context otherwise indicates, all references in this report to "Range," "we," "us" or "our" are to Range Resources Corporation and its directly and indirectly owned subsidiaries. Unless otherwise noted, all information in the report relating to natural gas, natural gas liquids and crude oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption "Glossary of Certain Defined Terms" at the end of Items 1 & 2. Business and Properties of this report.

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended ("Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: drilling plans; planned wells; rig count; our 2023 capital budget; reserve estimates; expectations regarding future economic and market conditions and their effects on us; our financial and operational outlook and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources and the benefits thereof. These statements typically contain words such as "may," "anticipates," "believes," "estimates," "expects," "plans," "predicts," "targets," "projects," "should," "would" or similar words, indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

While we believe that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. For a description of known material factors that could cause our actual results to differ from those in the forward-looking statements, see other factors discussed in Item 1A. Risk Factors.

Actual results may vary significantly from those anticipated due to many factors, including:

- conditions in the oil and gas industry, including supply and demand levels for natural gas, crude oil and natural gas liquids ("NGLs") and the resulting impact on price;
- the availability and volatility of securities, capital or credit markets and the cost of capital to fund our operation and business strategy;
- accuracy and fluctuations in our reserves estimates due to regulations, reservoir performance or sustained low commodity prices;
- lack of, or disruption in, access to pipelines or other transportation methods;
- ability to develop existing reserves or acquire new reserves;
- drilling and operating risks;
- well production timing;
- changes in political or economic conditions in the United States and more specifically in our key operating market;
- prices and availability of goods and services, including drilling rigs, material, labor and third-party infrastructure;
- unforeseen hazards such as weather conditions, health pandemics, acts of war or terrorist acts;
- security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems or breaches of the information technology systems, facilities and infrastructure of third parties with which we transact business;
- changes in safety, health, environmental, tax and other regulations or requirements or initiatives including those addressing the impact of global climate change, air emissions, waste or water management;
- other geological, operating and economic considerations;
- the ability and willingness of current or potential lenders, derivative contract counterparties, customers and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us; or
- other factors discussed in Items 1 and 2. Business and Properties, Item 1A. Risk Factors, Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures about Market Risk and elsewhere in this report.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise except as required by law. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Range Resources Corporation, a Delaware corporation, is a Fort Worth, Texas-based independent natural gas, NGLs and oil company, engaged in the exploration, development and acquisition of natural gas and oil properties in the United States. Our principal area of operations is the Marcellus Shale in Pennsylvania. Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 (telephone (817) 870-2601). We also maintain field offices in our area of operations. Our common stock is listed and trades on the New York Stock Exchange (the "NYSE") under the ticker symbol "RRC." Range Resources Corporation was incorporated in 1980. At December 31, 2022, we had 238.9 million shares outstanding. At year-end 2022, our proved reserves had the following characteristics:

- 18.1 Tcfe of proved reserves;
- 65% natural gas, 33% NGLs and 2% crude oil and condensate;
- 60% proved developed;
- nearly 100% operated;
- a reserve life index of approximately 22 years (based on fourth quarter 2022 production);
- a pretax present value of $29.6 billion of future net cash flows, discounted at 10% per annum ("PV-10"[(a)]); and
- a standardized after-tax measure of discounted future net cash flows of $24.5 billion.

(a) PV-10 is considered a non-GAAP financial measure as defined by the U.S. Securities and Exchange Commission (the "SEC"). We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and security analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $5.0 billion at December 31, 2022. PV-10 for December 31, 2022 was determined using NYMEX benchmark prices of $6.36 per mcf for natural gas and $94.13 per bbl for oil.

Our estimated proved reserves increased 2% to 18.1 Tcfe at December 31, 2022 from 17.8 Tcfe at December 31, 2021. Reserve additions were the result of a successful development program and completion optimizations that resulted in improved well performance. The 2022 reserve additions, higher prices and a positive revision of 716.2 Bcfe for previously proved undeveloped properties added back to our five-year development plan were partially offset by 2022 production volumes of 774.1 Bcfe and 1.4 Tcfe of reserves reclassified to unproved because these wells are no longer expected to be drilled within the original five-year development horizon. These wells were removed due to the outperformance of existing wells which resulted in a higher utilization of in-field gathering capacity and a reallocation of capital due to the drilling of longer laterals on existing locations. We believe these unproved reserves are likely to be included in our future proved reserves as these locations are added back into our five-year development plan.

Highlights of our 2022 production were:

- total production of 539.4 Bcf of natural gas, 36.4 Mmbbls of NGLs and 2.7 Mmbbls of crude oil and condensate; and
- average daily production was 2.12 Bcfe per day compared to 2.13 Bcfe per day in 2021.

Executive Summary for 2022

Because our production is approximately 70% natural gas, natural gas prices generally constitute the primary variable in our operating results. Over the last few years, New York Mercantile Exchange ("NYMEX") natural gas prices have been volatile. Since the beginning of 2020, the daily close for natural gas prices have been as low as $1.50 per Mmbtu and as high as $9.35 per Mmbtu. The prices we receive for all our products are largely based on current market prices which are beyond our control but are managed through diversity in our sales agreements combined with an active commodity price hedging program. Currently, our focus is on generating free cash flow through controlling costs and operational efficiencies, while strengthening our balance sheet and returning free cash flow to stockholders. During 2022, we:

- reduced total debt $1.1 billion;
- reduced cost of debt with $500.0 million aggregate principal amount of new 4.75% senior notes due 2030;
- realized a significant improvement in our debt metrics, including our debt to capitalization ratio, from year-end 2021;

- reinstated quarterly dividend payments in the third and fourth quarter for a total distributed of $38.6 million;
- repurchased approximately $400.0 million of our common stock;
- increased our cash flow from operating activities by $1.1 billion;
- recognized an average realized price (excluding derivative settlements and third party transportation costs) increase of 53% from 2021;
- reduced our depletion, depreciation and amortization rate per mcfe 2% from 2021;
- increased our estimates of proved reserves at December 31, 2022 to 18.1 Tcfe from 17.8 Tcfe at December 31, 2021 which includes 1.7 Tcfe of drilling additions;
- published our annual corporate sustainability report which discusses our continued focus and commitment to safety and environmental protection and the communities where we work;
- doubled our leak detection inspections from four to eight times a year;
- successfully pilot tested compressed air pneumatic controllers;
- continued with our innovative water recycling program;
- continued utilizing an electric hydraulic fracturing fleet along with dual fuel drilling rigs;
- achieved a 50% reduction in number of workforce recordable injuries compared to 2021; and
- achieved a 50% reduction in number of workforce days away restricted treatment injuries compared to 2021.

Available Information

Our corporate website is available at http://www.rangeresources.com. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing we make with the SEC. We make available, free of charge on our website, the annual report on Form 10-K, our proxy statement, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after filing such reports with the SEC. Other information such as presentations, our corporate sustainability report, our Corporate Governance Guidelines, the charters of each board committee and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including our President and Chief Executive Officer and Chief Financial Officer.

The SEC maintains an internet website that contains reports, proxy and information statements and other information regarding issuers, including Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at http://www.sec.gov.

Our Business Strategy

Our overarching business objective is to build stockholder value through returns focused development of natural gas properties. Our strategy to achieve our business objective is to generate consistent cash flows from reserves and production through internally generated drilling projects. We routinely evaluate complementary, value-based acquisitions and dispositions. Our strategy requires us to make significant investments and financial commitments in technical staff, acreage, seismic data, drilling and completion technology and gathering and transportation arrangements to build drilling inventory and market our products. Our strategy has the following key elements:

- commit to environmental protection and worker and community safety;
- concentrate in our core operating area;
- focus on cost efficiency;
- maintain a high-quality multi-year drilling inventory;
- maintain a long-life reserve base with a low base decline rate;
- market our products to a large number of customers in diverse markets under a variety of commercial terms;
- maintain operational and financial flexibility; and
- provide employee equity ownership and incentive compensation aligned with our stakeholders' interests.

These elements are anchored by our interests in the Marcellus Shale located in Pennsylvania which is anticipated to have remaining productive life in excess of 50 years.

Commit to Environmental Protection and Worker and Community Safety. We strive to implement technologies and commercial practices to minimize potential adverse impacts from the development of our properties on the environment, worker health and safety and the safety of the communities where we operate. We analyze and review performance while striving for continual improvement by working with peer companies, regulators, non-governmental organizations, industries not related to the oil and natural gas industry and other engaged stakeholders. We expect every employee to maintain safe operations, minimize environmental impact and conduct their daily business with the highest ethical standards.

Concentrate in Our Core Operating Area. We currently operate in Pennsylvania. Concentrating our drilling and producing activities allows us to develop the regional expertise needed to interpret specific geological and operating conditions and develop economies of scale. Operating in our core area also allows us to pursue our goal of consistent production at attractive returns. We intend to further develop our acreage and improve our operating and financial results through the use of technology and detailed analysis of our properties. We periodically evaluate and pursue acquisition opportunities (including opportunities to acquire particular natural gas and oil properties or entities owning natural gas and oil assets) and at any given time we may be in various stages of evaluating such opportunities.

Focus on Cost Efficiency. We concentrate in areas which we believe to have sizable hydrocarbon deposits in place that will allow economic production while controlling costs. Because there is little long-term competitive sales price advantage available to a commodity producer, the costs to find, develop, and produce a commodity are important to organizational sustainability and long-term stockholder value creation. We endeavor to control costs such that our cost to find, develop and produce natural gas, NGLs and oil is one of the lowest in the industry. We operate almost all of our total net production and believe that our extensive knowledge of the geologic and operating conditions in the areas where we operate provides us with the ability to achieve operational efficiencies.

Maintain a High-Quality Multi-Year Drilling Inventory. We focus on areas with multiple prospective and productive horizons and development opportunities. We use our technical expertise to build and maintain a multi-year drilling inventory. We believe that a large, high-quality multi-year inventory of drilling projects increases our ability to efficiently plan for economic production. Currently, we have over 3,300 proven and unproven Marcellus drilling locations in inventory.

Maintain a Long-Life Reserve Base with a Low Base Decline Rate. Long-life natural gas and oil reserves provide a more stable platform than short-life reserves. Long-life reserves with relatively low decline rates reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long-life natural gas and oil reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale. Long-life reserves also offer upside from technology enhancements.

Market Our Products to a Large Number of Customers in Diverse Markets Under a Variety of Commercial Terms. We market our natural gas, NGLs, crude oil and condensate to a large number of customers in both domestic and international markets to maximize cash flow and diversify risk. We hold numerous firm transportation contracts on multiple pipelines to enable us to transport and sell natural gas and NGLs in the Midwest, Gulf Coast, Southeast, Northeast and international markets. We sell our products under a variety of price indexes and price formulas that assist us in optimizing regional price differentials and commodity price volatility.

Maintain Operational and Financial Flexibility. Because of the risks involved in drilling, coupled with changing commodity prices, we are flexible and may adjust our capital budget throughout the year. If certain areas generate higher than anticipated returns, we may accelerate development in those areas and decrease expenditures elsewhere. We also believe in maintaining ample liquidity, using commodity derivatives to help stabilize our realized prices and focusing on financial discipline. We believe this provides more predictable cash flows and financial results.

Provide Employee Equity Ownership and Incentive Compensation Aligned with Our Stakeholders' Interests. We want our employees to think and act like business owners. To achieve this, we reward and encourage them through equity ownership in Range. All full-time employees are eligible to receive equity grants. As of December 31, 2022, our employees and directors owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $300.0 million. We seek to align our incentive compensation with stakeholders' interests and key business objectives and members of our board of directors annually engage with stockholders to discuss our incentive compensation framework.

Significant Accomplishments in 2022

- ***Proved reserves*** – Total proved reserves increased 2% in 2022 compared to 2021, from 17.8 Tcfe to 18.1 Tcfe. This achievement is the result of existing quality production and efficient development. We believe the quality of our technical teams and our substantial inventory of high quality Marcellus Shale drilling locations provide the basis for future proved reserves and production.
- ***Production*** – In 2022, our production averaged 2.12 Bcfe per day compared to 2.13 Bcfe per day in 2021. Our capital program is designed to allocate investments based on projects that maximize returns while minimizing controllable costs associated with production activities. We intend to continue our disciplined investment in our Marcellus Shale assets.
- ***Focus on financial flexibility*** – As of December 31, 2022, we maintained a $4.0 billion bank credit facility, with a borrowing base of $3.0 billion and committed borrowing capacity of $1.5 billion. We endeavor to maintain a strong liquidity position. In 2022, we reduced our aggregate principal amount of debt by $1.1 billion. We ended 2022 with strong liquidity with $1.2 billion available under the credit facility. Actual capital budget spending was slightly higher than the original plan at approximately $492.0 million reflecting the impact of cost inflation. As we have done historically, we may adjust our capital program, divest assets and use derivatives to protect a portion of our future cash flow from commodity price volatility to reduce the risk of returns on investment and maintain ample liquidity.
- ***Successful drilling program*** – In 2022, we drilled 60 gross natural gas wells and our overall drilling success rate was 100%. We continue to maintain and optimize a sufficient inventory of drilled lateral footage which is critical to our ability to consistently sustain production each year on a cost effective and efficient basis. Controlling the costs to find, develop and produce natural gas, NGLs and oil is critical in creating long-term stockholder value. Our focus areas are characterized by large, contiguous acreage positions and multiple stacked geologic horizons.
- ***Focus on safe, responsible and sustainable operations*** – We believe we are on track to achieve our goal of net zero GHG emissions by year-end 2025, which includes Scope 1 and Scope 2 emissions. We increased our leak detection inspections to eight times each year. We continued to recycle approximately 100% of our produced water. Electric and dual fuel drilling rigs continue to reduce emissions. We had no serious or severe injuries for employees or contractors during the year.

Segment and Geographical Information

Our operations consist of one reportable segment. We have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Our exploration and production operations are limited to onshore United States.

Outlook for 2023

For 2023, we expect our capital budget to be in the range of $570.0 million to $615.0 million for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. This budget includes $540.0 million to $565.0 million for drilling costs and $30.0 million to $50.0 million for acreage and other expenditures and is expected to achieve 2023 production similar to 2022 production volumes. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. Throughout the year, we allocate capital on a project-by-project basis. Our expectation for 2023 is for our capital expenditure program to be funded with operating cash flows. However, in the event our 2023 capital requirements exceed our internally generated cash flow, we may reduce the capital budget, draw on our bank credit facility and/or debt or equity financing may be used to fund these requirements. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2023 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions.

Our primary near-term focus includes the following:

- operate safely and efficiently;
- manage liquidity and further improve financial strength;
- focus on organic opportunities through disciplined capital investments;
- improve operational efficiencies and economic returns;
- reduce emissions and target net-zero Scope 1 and Scope 2 GHG emissions by year-end 2025;
- attract and retain quality employees; and
- align employee incentives with our stockholders' interests and key business objectives.

Proved Reserves

The following table sets forth our estimated proved reserves for years ended 2022, 2021 and 2020 based on the average of prices on the first day of each month of the given calendar year, in accordance with SEC rules. Oil includes both crude oil and condensate. We have no natural gas, NGLs or oil reserves from non-traditional sources. Additionally, we do not provide optional disclosures of probable or possible reserves.

	Summary of Oil and Gas Reserves as of Year-End Based on Average Prices				
Reserve Category	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe) [(a)]	%
2022:					
Proved					
Developed	7,230,313	594,931	22,213	10,933,180	60%
Undeveloped	4,567,659	409,027	20,443	7,144,476	40%
Total Proved	11,797,972	1,003,958	42,656	18,077,656	100%
2021:					
Proved					
Developed	6,809,849	577,507	23,834	10,417,887	59%
Undeveloped	4,642,232	423,798	28,762	7,357,597	41%
Total Proved	11,452,081	1,001,305	52,596	17,775,484	100%
2020:					
Proved					
Developed	6,350,057	550,771	22,976	9,792,540	57%
Undeveloped	4,798,503	400,695	34,650	7,410,574	43%
Total Proved	11,148,560	951,466	57,626	17,203,114	100%

[(a)] Oil and NGLs volumes are converted to mcfe at the rate of one barrel equals six mcf based upon the relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Reserve Estimation

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. We have established internal controls over our reserves estimation process and procedures to support the accurate and timely preparation and disclosure of reserve estimates in accordance with SEC requirements. We also had Netherland, Sewell & Associates, Inc., an independent petroleum consultant, conduct an audit of our year-end 2022 reserves. The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates. This engineering firm was selected for its geographic expertise and its historical experience in engineering certain properties. The proved reserve audits performed for 2022, 2021 and 2020, in the aggregate, represented 96%, 97% and 97% of our proved reserves. The reserve audits performed for 2022, 2021 and 2020, in the aggregate, represented 96%, 97% and 97% of our 2022, 2021 and 2020 associated pretax present value of proved reserves discounted at ten percent. A copy of the summary reserve report prepared by our independent petroleum consultant is included as an exhibit to this Annual Report on Form 10-K. The technical person at our independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of data furnished during the reserve audit process. Throughout the year, our technical team meets periodically with representatives of our independent petroleum consultant to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserve estimation process, our senior management reviews and approves significant changes to our proved reserves. We provide historical information to our consultant for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. Our consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review identified reserve differences. Our reserve auditor estimates of proved reserves and the pretax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area, some of our estimates may be greater and some may be less than the estimates of the reserve auditor. When such differences do not exceed 10% in the aggregate, our reserve auditor is satisfied that the proved reserves and pretax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences, if any, are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our independent petroleum consultants have been less than 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, Mr. Alan Farquharson, who reports directly to our President and Chief Executive Officer. Our Senior Vice President of Reservoir Engineering and Economics holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources and has more than forty years of engineering experience in the oil and gas industry. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions. During the year ended December 31, 2022, we did not file any reports with any federal authority or agency with respect to our estimate of natural gas and oil reserves.

Reserve Technologies

Proved reserves are those quantities of natural gas, NGLs and oil that 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of natural gas, NGLs and oil actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal technical staff employs technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, decline curve analysis, well logs, geologic maps and available downhole and production data, seismic data, well test data, reservoir simulation modeling and implementation and application of enhanced data analytics.

Proved undeveloped reserves (or "PUDs") include reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a major expenditure is required for completion. PUD reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic production. Undrilled locations may be classified as having PUD reserves only if an ability and intent has been established to drill the reserves within five years, unless specific circumstances justify a longer time period.

Reporting of Natural Gas Liquids

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2022, NGLs represented approximately 33% of our total proved reserves on an mcf equivalent basis. NGLs are products priced by the gallon (and sold by the barrel) to our customers. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels. Prices for a barrel of NGLs in 2022 averaged approximately 38% of the average price for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. We currently include ethane in our proved reserves which match volumes to be delivered under our existing long-term, extendable ethane contracts.

Proved Undeveloped Reserves

As of December 31, 2022, our PUDs totaled 20.4 Mmbbls of crude oil, 409.0 Mmbbls of NGLs and 4.6 Tcf of natural gas, for a total of 7.1 Tcfe. Costs incurred in 2022 relating to the development of PUDs were approximately $430.0 million. All PUD drilling locations are scheduled to be drilled prior to the end of 2027. As of December 31, 2022, we have 87.8 Bcfe of reserves that have been reported for more than five years from their original booking date, which is in the process of being drilled and completed and expected to turn to sales in 2023. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 1.1 Tcfe of PUDs into proved developed reserves;
- addition of 1.6 Tcfe new PUDs from drilling; and
- 759.3 Bcfe net negative revision with 1.4 Tcfe of reserves reclassified to unproved because of previously planned wells not expected to be drilled within the original five-year development horizon partially offset by positive revisions of 622.6 Bcfe which includes 716.2 Bcfe for previously proved undeveloped properties added back to our five year development plan.

For an additional description of changes in PUDs for 2022, see Note 17 to our consolidated financial statements. We believe our PUDs reclassified to unproved can be included in our future proved reserves as these locations are added back into our five-year development plan.

Proved Reserves (PV-10)

The following table sets forth the estimated future net cash flows, excluding open derivative contracts, from proved reserves, the present value of those net cash flows discounted at a rate of 10% (PV-10), and the expected benchmark prices and average field prices used in projecting net cash flows over the past five years. Our reserve estimates do not include any probable or possible reserves (in millions, except prices):

	2022	2021	2020	2019	2018
Future net cash flows	$ 78,650	$ 39,919	$ 9,795	$ 22,179	$ 34,836
Present value:					
Before income tax	29,554	14,868	2,981	7,561	13,173
After income tax (Standardized Measure)	24,545	12,485	2,846	6,629	11,116
Benchmark prices (NYMEX):					
Gas price (per mcf)	6.36	3.60	1.98	2.58	3.10
Oil price (per bbl)	94.13	66.34	39.77	55.73	65.55
Wellhead prices:					
Gas price (per mcf)	6.08	3.30	1.68	2.38	2.98
Oil price (per bbl)	87.14	59.35	30.13	49.24	59.96
NGLs price (per bbl)	38.35	28.41	16.14	17.32	25.22

Future net cash flows represent projected revenues from the sale of proved reserves, net of production and development costs (including transportation and gathering expenses, operating expenses and production taxes). Revenues are based on a twelve-month unweighted average of the first day of the month pricing, without escalation. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current economic conditions at each year-end. There can be no assurance that the proved reserves will be produced in the future or that prices, production or development costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Property Overview

Currently, our natural gas and oil operations are concentrated in the Appalachian region of the United States, and more specifically, in the Marcellus Shale in Pennsylvania. Our properties consist of interests in developed and undeveloped natural gas and oil leases. These interests entitle us to drill for and produce natural gas, NGLs, crude oil and condensate from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, royalty and overriding royalty interests.

We hold a large portfolio of drilling opportunities beyond the five-year horizon of proved reserves and therefore a significant unbooked resource potential within the Marcellus, Utica/Point Pleasant and Upper Devonian formations. We own 1,428 net producing wells in Pennsylvania, almost all of which we operate. Our average working interest in this region is 95%. As of December 31, 2022 we have approximately 894,000 gross (783,000 net) acres under lease. During 2022, we averaged approximately two horizontal drilling rigs in the field and expect to run an average of two horizontal drilling rigs throughout 2023.

The following table sets forth annual production volumes, average sales prices and production cost data for our wells in the Marcellus Shale play which, in 2020, was the only field in which our reserves were greater than 15% of our total proved reserves. For the years ended December 31, 2022 and 2021, substantially all of our reserves were located in the Marcellus Shale.

	Marcellus Shale		
	2022	2021	2020
Production:			
Natural gas (Mmcf)	538,865	540,824	544,079
NGLs (Mbbls)	36,369	36,365	36,185
Crude oil and condensate (Mbbls)	2,704	3,032	2,599
Total Mmcfe [(a)]	773,304	777,205	776,786
Sales Prices: [(b)]			
Natural gas (per mcf)	$ 4.98	$ 2.29	$ 0.49
NGLs (per bbl)	20.41	17.12	4.91
Crude oil and condensate (per bbl)	87.90	59.76	29.24
Total (per mcfe) [(a)]	4.74	2.62	0.67
Production Costs:			
Lease operating (per mcfe)	$ 0.11	$ 0.10	$ 0.10
Taxes other than income (per mcfe) [(c)]	0.04	0.04	0.02

(a) Oil and NGLs volumes are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

(b) We do not record derivatives or the results of derivatives at the field level. Includes deductions for third-party transportation, gathering and compression expense.

(c) Includes Pennsylvania impact fee.

Reserves at December 31, 2022 were 18.1 Tcfe, an increase of 302.2 Bcfe, or 2%, from 2021. Drilling additions of 1.7 Tcfe, favorable pricing revisions, positive performance revisions of 72.0 Bcfe and 716.2 Bcfe of previously proved undeveloped reserves added back to our five year development plan were partially offset by production of 773.3 Bcfe and downward revisions for proved undeveloped reserves deferred beyond our current five-year development plan of 1.4 Tcfe. These wells were removed due to the outperformance of existing wells which resulted in a higher utilization of in-field gathering capacity and a reallocation of capital due to the drilling of longer laterals on existing locations. In 2022, our annual production was only slightly lower than production in 2021. During 2022, we spent $460.7 million to drill 60 (59.0 net) development wells, all of which were productive. There were no exploratory wells drilled. At December 31, 2022, we had an inventory of over 3,300 proven and unproven drilling locations. During the year, we drilled 60 proven locations in the Appalachian region, added 154 new proven drilling locations and deleted 87 proven drilling locations with deleted reserves reclassified to unproved due to lower future capital spending, improved well performance and the impact of the five-year rule on wells not to be drilled within the original development horizon. During the year, we achieved a 100% drilling success rate.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2022. If we own both a royalty and a working interest in a well, such interest is included in the table below. Wells are classified as natural gas or crude oil according to their predominant production stream. We do not have a significant number of dual completions.

	Total Wells		Average Working
	Gross	Net	Interest
Natural gas	1,506	1,427	95%
Crude oil	2	1	51%
Total	1,508	1,428	95%

Productive wells are producing wells and wells mechanically capable of production. The day-to-day operations of natural gas and oil properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Drilling Activity

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. This information should not be indicative of future performance nor should it be assumed that there was any correlation between the number of productive wells and the natural gas and oil reserves generated thereby. As of December 31, 2022, we had 41 gross (38.0 net) wells in the process of drilling or active completions stage. In addition, there were 11.0 gross (11.0 net) wells waiting on completion or waiting on pipelines at year-end 2022.

	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	60.0	59.0	58.0	57.1	52.0	51.4
Dry	—	—	—	—	—	—
Exploratory wells						
Productive	—	—	1.0	1.0	—	—
Dry	—	—	—	—	—	—
Total wells						
Productive	60.0	59.0	59.0	58.1	52.0	51.4
Dry	—	—	—	—	—	—
Total	60.0	59.0	59.0	58.1	52.0	51.4
Success ratio	100%	100%	100%	100%	100%	100%

Gross and Net Acreage

We own interests in developed and undeveloped natural gas and oil acreage. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production even though shallower or deeper horizons may not have been fully explored. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves. The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2022. Acreage related to option acreage, royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Michigan	111	111	—	—	111	111
New York	—	—	2,265	567	2,265	567
Oklahoma	21,867	9,329	—	—	21,867	9,329
Pennsylvania	789,642	697,975	68,179	65,039	857,821	763,014
Texas	6,242	4,323	—	—	6,242	4,323
West Virginia	5,876	5,197	—	—	5,876	5,197
	823,738	716,935	70,444	65,606	894,182	782,541
Average working interest		87%		93%		88%

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2023	18,768	17,875	27%
2024	12,226	11,300	17%
2025	9,849	8,993	14%
2026	17,915	17,495	27%
2027	8,607	8,570	13%

In all cases, the drilling of a commercial well will hold acreage beyond the lease expiration date. We have leased acreage that is subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. However, we have in the past been able, and expect in the future to be able to extend the lease terms of some of these leases and sell or exchange some of these leases with other companies. The expirations included in the table above do not take into account the fact that we may be able to extend the lease terms. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and we expect to allow additional acreage to expire in the future. We currently have no proved undeveloped reserve locations scheduled to be drilled after lease expiration.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value, of the properties. Burdens on properties may include:

- customary royalty or overriding royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- net profit interests.

Delivery Commitments

For a discussion of our delivery commitments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Delivery Commitments*.

Human Capital Management

We believe our employees provide the foundation of our success. Successful execution of our strategy is dependent on attracting, developing and retaining our skilled employees and members of our management team. The abilities, experience and industry knowledge of our employees significantly benefit our operations and performance and in order to maximize the contributions of our employees, we regularly evaluate, modify and enhance our policies and practices, including compensation to increase employee engagement, productivity and efficiency. As of January 1, 2023, we had 544 full time employees, none of whom are currently covered by a labor union or other collective bargaining arrangement.

Compensation and Benefits. We review compensation for all employees at least annually to adjust for market conditions and to attract and retain a highly skilled workforce. We encourage our employees to take full advantage of our benefits and programs we offer. In addition to competitive base wages, other benefits include an annual bonus plan, long-term incentive plan, company-match 401(k) plan, healthcare and insurance benefits, flexible spending accounts and employee assistance programs.

Our compensation program includes eligibility for all full-time employees to receive equity awards which we believe is somewhat unique among our peers and encourages every employee to think like an owner of the business and be vested in its success. We believe these practices, and those further described below, are the key drivers in our very low voluntary turnover rates, which averaged less than 4.5% over the five-year period ended December 31, 2022.

Health and Safety. We believe health and safety is a core value and engrained in all aspects of our business. This value is reflected in our strong safety culture that emphasizes personal responsibility and safety leadership both for our employees and our contractors on our worksites. Our comprehensive environmental, health and safety (EHS) management system establishes a corporate governance framework for EHS compliance and performance and covers all elements of our operating lifecycle. These practices and the commitment of our management and our employees to our culture of safety have resulted in only four OSHA recordable incidents in 3.6 million work hours over the three-year period from 2020 through 2022, for an average Total Recordable Incident Rate of 0.22 over that three-year period.

Recruiting, Hiring and Advancement. Due to the cyclical nature of our business and the fluctuations in activity that can occur, we take a conservative approach to our headcount, carefully evaluating whether a new hire is necessary for an open position or whether we can fill the position by expanding the role of a current employee or several employees. In this way, we provide employees with opportunities to learn new roles and develop their skills horizontally and vertically and limit or minimize layoffs and fluctuations when downturns occur.

We identify qualified candidates by promoting positions internally, engaging in recruiting through our website platforms, campus outreach, internships and attending job fairs. In our recruiting and hiring efforts, we seek to foster a culture of mutual respect and strictly comply with all applicable federal, state and local laws governing non-discrimination in employment. We treat all applicants with the same high level of respect regardless of their gender, ethnicity, religion, national origin, age, marital status, political affiliation, sexual orientation, gender identity, disability or protected veteran status. This philosophy extends to all employees throughout the lifecycle of employment.

Additional information about our commitment to human capital is available on our website. Note that the information on our website is not incorporated by reference into this filing.

Executive Officers of the Registrant

Our executive officers and their ages as of February 1, 2023, are as follows:

	Age	Position
Jeffrey L. Ventura	65	Chief Executive Officer and President
Mark S. Scucchi	45	Executive Vice President – Chief Financial Officer
Dennis L. Degner	50	Executive Vice President – Chief Operating Officer
Dori A. Ginn	65	Senior Vice President – Controller and Principal Accounting Officer
David P. Poole	60	Senior Vice President – General Counsel and Corporate Secretary

Jeffrey L. Ventura, chief executive officer and president, joined Range in 2003 as chief operating officer and became a director in 2005. Mr. Ventura was named President, effective May 2008 and Chief Executive Officer, effective January 2012. Previously, Mr. Ventura served as president and chief operating officer of Matador Petroleum Corporation which he joined in 1997. Prior to his service at Matador, Mr. Ventura spent eight years at Maxus Energy Corporation where he managed various engineering, exploration and development operations and was responsible for the coordination of engineering technology. Previously, Mr. Ventura was with Tenneco Oil Exploration and Production, where he held various engineering and operating positions. Mr. Ventura holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University. Mr. Ventura is a member of the Society of Petroleum Engineers, the American Association of Petroleum Geologists and the Texas Society of Professional Engineers.

Mark S. Scucchi, executive vice president – chief financial officer, joined Range in 2008. Mr. Scucchi was named senior vice president – chief financial officer in 2018. Previously, Mr. Scucchi served as vice president – finance & treasurer. Prior to joining Range, Mr. Scucchi was with JPMorgan Securities providing commercial and investment banking services to small and mid-cap technology companies. Before joining JPMorgan Securities, Mr. Scucchi spent a number of years at Ernst & Young LLP in the audit practice. Mr. Scucchi earned a Bachelor of Science in Business Administration from Georgetown University and a Master of Science in Accountancy from the University of Notre Dame. Mr. Scucchi is a CFA Charterholder and a licensed certified public accountant in the state of Texas.

Dennis L. Degner, executive vice president of operations, joined Range in 2010. Mr. Degner was named senior vice president of operations in 2018 and Chief Operating Officer in May 2019. Previously, Mr. Degner served as vice president of Appalachia. Mr. Degner has more than 20 years of oil and gas experience, having worked in a variety of technical and managerial positions across the United States including Texas, Louisiana, Wyoming, Colorado and Pennsylvania. Prior to joining Range, Mr. Degner held positions with EnCana, Sierra Engineering and Halliburton. Mr. Degner is a member of the Society of Petroleum Engineers. Mr. Degner holds a Bachelor of Science Degree in Agricultural Engineering from Texas A&M University.

Dori A. Ginn, senior vice president – controller and principal accounting officer, joined Range in 2001. Ms. Ginn has held the positions of financial reporting manager, vice president and controller before being elected to principal accounting officer in September 2009. Prior to joining Range, she held various accounting positions with Doskocil Manufacturing Company and Texas Oil and Gas Corporation. Ms. Ginn earned a Bachelor of Business Administration in Accounting from the University of Texas at Arlington. She is a certified public accountant licensed in the state of Texas.

David P. Poole, senior vice president – general counsel and corporate secretary, joined Range in 2008. Mr. Poole has over 30 years of legal experience. From May 2004 until March 2008, he was with TXU Corp., serving last as executive vice president – legal, and general counsel. Prior to joining TXU, Mr. Poole spent 16 years with Hunton & Williams LLP and its predecessor, where he was a partner and last served as the managing partner of the Dallas office. Mr. Poole graduated from Texas Tech University with a Bachelor of Science in Petroleum Engineering and earned a Juris Doctor magna cum laude from Texas Tech University School of Law.

Competition

Competition exists in all sectors of the oil and gas industry and in particular, we encounter substantial competition in developing and acquiring natural gas and oil properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil and gas companies as well as numerous independent oil and gas companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. We face competition for pipeline and other services to transport our product to markets, particularly in the Northeastern portion of the United States. We also face competition from companies that supply alternative sources of energy, such as wind, solar power and other renewables. Competition will increase as alternative energy technology becomes more reliable and governments throughout the world support or mandate the use of such alternative energy.

Competitive advantage is gained in the oil and gas exploration and development industry by employing well-trained and experienced personnel who make prudent capital investment decisions based on management direction, embrace technological innovation and are focused on price and cost management. We have a team of dedicated employees who represent the professional disciplines and sciences that we believe are necessary to allow us to maximize the long-term profitability and net asset value inherent in our physical assets. For more information, see Item 1A. Risk Factors.

Marketing and Customers

We market the majority of our natural gas, NGLs, crude oil and condensate production from the properties we operate for our interest, and that of the other working interest owners. We pay our royalty owners from the sales attributable to our working interest. Natural gas, NGLs and oil purchasers are selected on the basis of price, credit quality and service reliability. For a summary of purchasers of our natural gas, NGLs and oil production that accounted for 10% or more of consolidated revenue, see Note 2 to our consolidated financial statements. Because alternative purchasers of natural gas and oil are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations. Production from our properties is marketed using methods that are consistent with industry practice. Natural gas is a commodity, and therefore, we typically receive market-based pricing for our produced natural gas. Sales prices for natural gas, NGLs and oil production are negotiated based on factors normally considered in the industry, such as index or spot price, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions.

We contract with a third-party to process our natural gas and extract from the produced natural gas heavier hydrocarbon streams (consisting predominately of ethane, propane, isobutane, normal butane and natural gasoline). Our natural gas production is sold to utilities, marketing and midstream companies and industrial users. Our NGLs production is typically sold to petrochemical end users, marketers/traders (both domestically and internationally) and natural gas processors. Our oil and condensate production is sold to crude oil processors, transporters and refining and marketing companies.

We enter into derivative transactions with unaffiliated third parties for a varying portion of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas, NGLs and oil prices. For a more detailed discussion, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We incur gathering and transportation expense to move our production from the wellhead, tanks and processing plants to purchaser-specified delivery points. These expenses vary and are primarily based on volume, distance shipped and the fee charged by the third-party gatherers and transporters. We also have contracts based on percent of proceeds. Transportation capacity on these gathering and transportation systems and pipelines is occasionally constrained. Our Appalachian production is transported on third-party pipelines on which we hold a certain amount of long-term contractual capacity. We attempt to balance sales, storage and transportation positions, which can include purchase of commodities from third parties for resale, to satisfy transportation commitments.

We have not experienced significant difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to transport and market all of our production or obtain favorable prices. We have entered into several ethane agreements to sell or transport ethane from our Marcellus Shale area. For more information, see Item 1A. Risk Factors – *Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and we rely on our ability to contract with those parties.*

Seasonal Nature of Business

Generally, but not always, the demand for natural gas and propane decreases during the spring and fall months and increases during the winter months and, in some areas, also increases during the summer months. Seasonal anomalies such as mild winters or hot summers also may impact this demand. In addition, pipelines, utilities, local distribution companies and industrial end-users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also impact the seasonality of demand.

Markets

Our ability to produce and market natural gas, NGLs and oil profitably depends on numerous factors beyond our control. The effect of these factors cannot be accurately predicted or anticipated. Although we cannot predict the occurrence of events that may affect commodity prices or the degree to which commodity prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production.

Governmental Regulation

Enterprises that sell securities in public markets are subject to regulatory oversight by federal agencies such as the SEC. The NYSE, a private stock exchange, also requires us to comply with listing requirements for our common stock. This regulatory oversight imposes on us the responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting and ensuring that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Failure to comply with the NYSE listing rules and regulations of the SEC could subject us to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could also result in the de-listing of our common stock, which could have an adverse effect on the market price of our common stock. Compliance with some of these rules and regulations is costly and regulations are subject to change or reinterpretation.

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state and local regulations, mandates and trade agreements. Governmental policies affecting the energy industry, such as taxes, tariffs, duties, price controls, subsidies, incentives, foreign exchange rates and import and export restrictions, can influence the viability and volume of production of certain commodities, the volume and types of imports and exports, whether unprocessed or processed commodity products are traded, and industry profitability. For example, the decision of the United States government to impose tariffs on certain Chinese imports and the resulting retaliation by the Chinese government imposing a twenty-five percent tariff on United States' liquefied natural gas exports have disrupted certain aspects of the energy market. Despite a trade agreement with China announced in January 2020, China's twenty-five percent tariff on imports of United States liquefied natural gas is expected to remain in place for now, but eventually could be eased by discretionary tariff exemptions granted to Chinese importers of United States liquefied natural gas or if discussions progress to a second phase agreement. Disruption and uncertainty of this sort can affect the price of oil and natural gas and may cause us to change our plans for exploration and production levels. An overview of relevant federal, state and local regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations, and the continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur, or past non-compliance with environmental laws or regulations may be discovered. See Item 1A. Risk Factors – *The natural gas industry is subject to extensive regulation.* We do not believe we are affected differently by these regulations than others in the industry.

General Overview. Our oil and gas operations are subject to various federal, state and local laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- leases;
- acquisition of seismic data;
- location of wells, pads, roads, impoundments, facilities or rights of way;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;
- drilling, casing and completion of wells;
- issuance of permits in connection with exploration, drilling, production, gathering, processing and transportation;
- well production, maintenance, operations and security;
- spill prevention and containment plans;
- emissions permitting or limitations;
- protection of endangered species;
- use, transportation, storage and disposal of hazardous waste, fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- hydraulic fracturing;
- water withdrawal and water transfer;
- operation of underground injection wells to dispose of produced water and other liquids;
- marketing of production;
- transportation of production; and
- health and safety of employees and contract service providers.

In August 2005, the United States Congress ("Congress") enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Range, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission (the "FERC"), in contravention of rules prescribed by the FERC. In January 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA. On January 12, 2023, FERC issued a final rule increasing the maximum civil penalty for violations of the NGA from $1,388,496 per day per violation to $1,496,035 per day per violation to account for inflation pursuant to the Federal Civil Penalties Inflation Adjustment Improvement Act of 2015. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to the FERC's jurisdiction which includes the reporting requirements under Order 704 (as defined and described below). Therefore, EPAct 2005 was a significant expansion of the FERC's enforcement authority. Range has not been affected differently than any other producer of natural gas by this act. Failure to comply with applicable laws and regulations with respect to EPAct 2005 could result in substantial penalties and the regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations with respect to EPAct 2005, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the FERC, other federal regulatory entities and the courts. We cannot predict when or whether any such proposals may become effective.

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

Intrastate gas pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates, varies from state to state. Additional proposals and proceedings that might affect the gas industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their impact, if any, on our operations. We believe that the regulation of intrastate gas pipeline transportation rates will not affect our operations in any way that is materially different from its effects on similarly situated competitors.

Natural gas processing. We depend on gas processing operations owned and operated by third parties. There can be no assurance that these processing operations will continue to be unregulated in the future. However, although the processing facilities may not be directly related, other laws and regulations may affect the availability of gas for processing, such as state regulation of production rates and maximum daily production allowable from gas wells, which could impact our processing.

Gas gathering. Section 1(b) of the NGA exempts gas gathering facilities from FERC jurisdiction. We believe that our gathering facilities meet the tests the FERC has traditionally used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Thus, we cannot guarantee that the jurisdictional status of our gas gathering facilities will remain unchanged.

We depend on gathering facilities owned and operated by third parties to gather production from our properties, and therefore we are affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulations affect the rates charged for gathering services at any of these third-party facilities, we may also be affected by these changes. We do not anticipate that we would be affected differently than similarly situated gas producers.

Regulation of transportation and sale of oil and natural gas liquids. Intrastate liquids pipeline transportation rates, terms and conditions are subject to regulation by numerous federal, state and local authorities and, in a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines that are also subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA"). We do not believe these regulations affect us differently than other producers.

The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

The FERCs regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. Under the FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flow. In January 2022, the FERC revised the adjustment for this index to be based on Producer Price Index for Finished Goods minus 0.21% for the five year period from July 1, 2021 to June 30, 2026. This adjustment became effective on March 1, 2022 and is subject to review every five years.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Environmental and Occupational Health and Safety Matters

Our operations are subject to numerous federal, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may include, but are not limited to:

- the acquisition of a permit before construction commences;
- restriction of the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines;
- governing the sourcing and disposal of water used in the drilling and completion process;
- limiting or prohibiting drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas;
- requiring some form of remedial action to prevent or mitigate pollution from existing and former operations such as plugging abandoned wells or closing earthen impoundments; and
- imposing substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings.

These laws and regulations also may restrict the rate of production. Moreover, changes in environmental laws and regulations often occur, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities or more restrictive waste handling, storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general.

Oil and gas activities have increasingly faced opposition from certain organizations and, in certain areas, have been restricted or banned by governmental authorities in response to concerns regarding the prevention of pollution or the protection of the environment. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties at sites we currently own or where we have sent wastes for disposal. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of drilling, or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected. The following is a summary of some of the environmental laws to which our operations are subject.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release or threatened release of a "hazardous substance" into the environment. These persons may include owners or operators of the disposal site or sites where the hazardous substance release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, all of these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties, pursuant to environmental statutes, common law or both, to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Although petroleum, including crude oil and natural gas, is not a "hazardous substance" under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that releases of such wastes may therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA. In addition, certain state laws also regulate the disposal of oil and natural gas wastes. New state and federal regulatory initiatives that could have a significant adverse impact on us may periodically be proposed and enacted.

Waste handling. We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state laws, which impose requirements related to the handling and disposal of non-hazardous solid wastes and hazardous wastes. Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are currently regulated by the United States Environmental Protection Agency ("EPA") and state agencies under RCRA's less stringent non-hazardous solid waste provisions. It is possible that these solid wastes could in the future be reclassified as hazardous wastes, whether by amendment of RCRA or adoption of new laws, which could significantly increase our costs to manage and dispose of such wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies in our industry. In December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. As a result, on April 23, 2019, the EPA decided to retain its current position on the regulation of oil and gas waste pursuant to RCRA. Nevertheless, any future changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used for many years for the exploration and production of crude oil and natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

Water discharges and use. The Federal Water Pollution Control Act, as amended (the "CWA"), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These laws also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of greater than threshold quantities of oil. We regularly review our natural gas and oil properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

The Oil Pollution Act of 1990, as amended ("OPA"), contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from an oil spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in substantial compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

The Underground Injection Control Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. In connection with our operations, Range may dispose of produced water in underground wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. However, because some states have become concerned that the disposal of produced water could, under certain circumstances, contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal. We currently do not utilize underground injection in our operations.

Hydraulic fracturing. Hydraulic fracturing, which has been used by the industry for over 60 years, is an important and common practice to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely apply hydraulic fracturing techniques as part of our operations. This process is typically regulated by state environmental agencies and oil and natural gas commissions; however, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final regulations under the Clean Air Act (as defined below) governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, while the Federal Bureau of Land Management released a final rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands in March 2015, on December 29, 2017, the United States Department of Interior rescinded the 2015 rule that would have set new environmental limitations on hydraulic fracturing, or fracking, on public lands because it believed the 2015 rule imposed administrative burdens and compliance costs that were not justified. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. On January 20, 2021, President Biden's first day in office, he issued an executive order which, among other things, revoked a series of executive orders, presidential memoranda, and draft agency guidance concerning environmental policy issued during the Trump administration. In addition to any actions by Congress, certain states in which we operate, including Pennsylvania, have adopted, and other states are considering adopting, regulations imposing or that could impose new or more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. States could also elect to prohibit hydraulic fracturing altogether, such as in the states of Washington, New York, Vermont, Maryland and Oregon (which temporarily suspended hydraulic fracturing until 2025). The governor of the State of California has also announced plans to ban hydraulic fracturing in that state by 2024. Local governments or political subdivisions also may seek to adopt ordinances within their jurisdiction regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. For instance, on February 25, 2021, the Delaware River Basin Commission, which supplies drinking water for more than 13 million people in Pennsylvania, Delaware, New Jersey, and New York, approved a final rule prohibiting high volume hydraulic fracturing in the Delaware River Basin, which includes a portion of the Marcellus Shale that overlaps the Delaware watershed, specifically in northeastern Pennsylvania and southern New York State. More recently, in December 2022, the Delaware River Basin Commission voted to prohibit wastewater from hydraulic fracturing operations from being deposited into the Delaware River Basins waters or land. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional, more significant, costs to comply with such requirements. As a result, we could also become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition, certain government reviews are underway that focus on environmental aspects of hydraulic fracturing practices. In December 2016, the EPA issued its final report on the potential of hydraulic fracturing to impact drinking water resources through water withdrawals, spills, fracturing directly into such resources, underground migration of liquids and gases, and inadequate treatment and discharge of wastewater which did not find evidence that these mechanisms have led to widespread, systematic impacts on drinking water resources. However, the EPA's report did identify future efforts that could be taken to further understand the potential of hydraulic fracturing to impact drinking water resources, including ground water and surface water monitoring in areas with hydraulically fractured oil and gas production wells. Based on the EPA's study, existing regulations and our practices, we do not believe our hydraulic fracturing operations are likely to impact drinking water resources, but the EPA study could result in initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

We believe that our hydraulic fracturing activities follow applicable industry practices and legal requirements for groundwater protection and that our hydraulic fracturing operations have not resulted in material environmental liabilities. We do not maintain insurance policies intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our existing insurance policies would cover any alleged third-party bodily injury and property damage caused by hydraulic fracturing including sudden and accidental pollution coverage.

Air emissions. The Clean Air Act of 1963, as amended (the "Clean Air Act") and comparable state laws restrict the emission of air pollutants from many sources. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals for emissions of pollutants. For example, pursuant to then President Obama's Strategy to Reduce Methane Emissions in August 2015, the EPA proposed new regulations that would set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities. The EPA finalized these new regulations on June 3, 2016 to be effective August 2, 2016; however, on June 12, 2017, the EPA announced a proposed two-year stay on these fugitive emissions standards "while the agency reconsiders them." On September 24, 2019, the EPA determined in a proposed rule that some of the requirements under the 2016 regulations and other prior rules are inappropriate because they affect sources that are not appropriately identified as part of the regulated source category and are unnecessary because they impose redundant requirements. As a result, the EPA proposed to rescind the inappropriate and redundant requirements while maintaining health and environmental protections from appropriately identified emission sources within the regulated source category. However, on November 2, 2021, the EPA issued a new proposed rule under the Clean Air Act aimed at reducing methane and other air pollution from both new and existing sources in the oil and natural gas industry. This proposed rule (i) would require states to reduce methane emissions from hundreds of thousands of existing sources nationwide for the first time, (ii) would expand current emissions reduction requirements for new, modified and reconstructed sources in the oil and natural gas industry, and (iii) when finalized, could require the use of advanced technologies as part of the "best system of emission reduction" for leak surveys at well sites and compressor stations. A public comment period was held and, on November 11, 2022, the EPA issued a supplement to its November 2021 proposed rule that aims to, among other things, (i) ensure that well sites are routinely monitored for leaks, with requirements based on the type and amount of equipment on site, (ii) require the deployment of innovative and advanced monitoring technologies by establishing performance requirements that can be met by a broader array of technologies, and (iii) prevent leaks from abandoned and unplugged wells by requiring documentation that well sites are properly closed and plugged before monitoring is allowed to end. A public comment period was held in January 2023, with a final rule expected later in 2023. When and if these standards become implemented and exactly what they will require is still not known. Also, in June 2018, the Pennsylvania Department of Environmental Protection ("DEP") adopted heightened permitting conditions for all newly permitted or modified natural gas compressor stations, processing plants and transmission stations constructed, modified, or operated in Pennsylvania in an effort to regulate emissions of the greenhouse gas at such sites. In furtherance of the DEP's mission to regulate methane emissions, in December 2019, the DEP proposed a rule to regulate emissions of volatile organic compounds (including methane) at existing well sites and compressor stations, which, among other obligations, would require natural gas operators to perform quarterly leak detection and remediation. The proposed rule was reviewed by the Pennsylvania Office of the Attorney General followed by a sixty day public comment period. Thereafter, the Pennsylvania Environmental Quality Board (the "PEQB") adopted the proposed rulemaking and an additional public comment period on July 27, 2020. On May 4, 2022, the PEQB withdrew the rule. On May 18, 2022, the rule was bifurcated into two separate rules – one for conventional oil and gas sources and one for unconventional oil and gas sources. On June 14, 2022, the PEQB adopted the rule for unconventional oil and gas sources. At its October 12, 2022 meeting, the PEQB adopted the rule for conventional oil and gas sources. However, on November 14, 2022, the Pennsylvania House Environmental Resources & Energy Committee disapproved such final-omitted regulation triggering a 14-calendar-day legislative review period. Since such legislative review period would have extended past the December 16, 2022 deadline for Pennsylvania to submit to the EPA a plan implementing the regulation of VOC emissions from oil and gas sources, the PEQB, on November 30, 2022, adopted the rule for conventional oil and gas sources as an emergency certified final-omitted rulemaking and former Governor Tom Wolf certified that promulgation of such is necessary to respond to an emergency circumstance. On December 10, 2022, both the conventional and unconventional rules were published as final. Since then, certain organizations have implemented legal action against the PEQB for failure to follow the requirements for rulemaking applicable to the conventional oil and natural gas industry. Compliance with these or any similar subsequently enacted regulatory initiatives could directly impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business.

Climate change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic conditions. Based on these findings, the EPA adopted regulations under the existing Clean Air Act establishing Title V and Prevention of Significant Deterioration ("PSD") permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. We could become subject to these Title V and PSD permitting reviews and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted rules requiring the reporting of GHG emissions from specified emission sources in the United States on an annual basis, including certain oil and natural gas production facilities, which include several of our facilities. We believe that our monitoring activities and reporting are in substantial compliance with applicable obligations.

Congress has from time to time considered legislation to reduce emissions of GHGs and there have been a number of federal regulatory initiatives to address GHG emissions in recent years, such as the establishing of Title V and PSD permitting reviews for GHG emissions, as described in more detail above. Further, on December 8, 2021, President Biden signed an executive order whereby the government was directed to cut its GHG emissions by 65% by the end of this decade, before reaching carbon neutrality by 2050. Additionally, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal or state laws and regulations, or international compacts could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements. On an international level, the United States was one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France the ("Paris Agreement") that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets, which agreement formally entered into force on November 4, 2016. While the United States formally accepted that agreement in September 2016, on June 1, 2017, then President Trump determined to withdraw the United States from the Paris Agreement. Under the terms of the Paris Agreement, the earliest possible effective date for withdrawal by the United States was November 4, 2020. However, on January 20, 2021, President Biden signed an executive order directing the United States to rejoin the Paris Agreement, which became official on February 19, 2021. It is not yet clear how rejoining the Paris Agreement or any separately negotiated agreement could impact us.

Upon taking office in January 2021, President Biden announced that he would demand that Congress enact legislation in the first year of his presidency that (i) establishes milestone environmental targets no later than the end of his first term in 2025, (ii) makes a significant investment in clean energy and climate research and innovation and (iii) incentivizes the rapid development of clean energy innovations across the economy, especially in communities most impacted by climate change. For example, on January 20, 2021, President Biden issued Executive Order No. 13990 requiring the heads of all federal agencies to review any agency activity under the Trump administration that would be considered to be inconsistent with the Biden administration’s environmental policies and consider suspending, revising, or rescinding those actions. As a result, in April 2021, the Secretary of the Interior issued two Secretarial Orders intended to prioritize action on climate change and revoking at least 12 orders issued under the Trump administration that are no longer consistent with the United States Department of the Interior's policy priorities under President Biden. Furthermore, on January 27, 2021, President Biden issued executive orders for the purpose of combatting climate change including pausing new oil and gas leases on federal land and cutting fossil fuel subsidies. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

We believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2022, nor do we anticipate that such expenditures will be material in 2023. However, we regularly incur expenditures and undertake projects to comply with environmental laws and to optimize our emissions performance. We anticipate those costs will continue to be incurred in the future.

Occupational health and safety. We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended (“OSHA”), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this glossary are used in this report.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. One billion cubic feet of gas.

bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

btu. One British thermal unit, an energy equivalence measure. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

Exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of oil and gas in another reservoir or to extend a known reservoir.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Henry Hub price. A natural gas benchmark price quoted at settlement date average.

mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

mcf. One thousand cubic feet of gas.

mcf per day. One thousand cubic feet of gas per day.

mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

mmbtu. One million British thermal units.

mmcf. One million cubic feet of gas.

mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline that can be collectively removed from produced natural gas, separated into these substances and sold.

Net acres or Net wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Present Value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after-tax present value is the Standardized Measure.

Productive well. A well that is producing oil or gas or that is capable of production.

Proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed reserves. Proved reserves 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 extracting equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Proved reserves. The quantities of crude oil, natural gas and NGLs that geological and engineering data can estimate with reasonable certainty to be economically producible within a reasonable time from known reservoirs under existing economic, operating and regulatory conditions prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reserve life index. Proved reserves at a point in time divided by the then production rate (annually or quarterly).

Royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

Royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission’s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

tcfe. One trillion cubic feet of natural gas equivalents, with one barrel of NGLs or crude oil being equivalent to 6,000 cubic feet of natural gas.

Unproved properties. Properties with no proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

Unconventional play. A term used in the oil and gas industry to refer to a play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds or (3) shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation or other special recovery processes in order to achieve economic flow rates.

ITEM 1A. RISK FACTORS

While we utilize robust processes and resources to identify and manage risks, we are subject to various risks and uncertainties in the course of our business, some of which are comparable to the risks any business is exposed to and some that are unique to our operations. The following summarizes the known material risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering making or maintaining an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the section entitled “Disclosures Regarding Forward-Looking Statements” and other information included and incorporated by reference into this Annual Report on Form 10-K. These risks are not the only risks we face. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we believe not to be material based on the information we have at this time. If any of the events described below as risks actually occur, it could materially harm our business, financial condition or results of operations or impair our ability to implement our business plans or complete development activities as expected. In that case, the market price of our common stock could decline or, if severe enough, the entire value of an investment in our securities could become worthless.

Economic risks related to our business

Volatility of natural gas, NGLs and oil prices significantly affects our cash flow and capital resources and could hamper our ability to operate economically. Natural gas, NGLs and oil prices are volatile, and a decline in prices adversely affects our profitability and financial condition. As a commodity business, the oil and gas industry is typically cyclical and we expect the volatility to continue. Natural gas prices are likely to affect us more than oil prices because approximately 65% of our proved reserves were natural gas as of December 31, 2022 and at times in the past, natural gas prices have been low compared to our costs to produce. Natural gas, NGLs and oil prices fluctuate in response to changes in supply and demand, market uncertainty and other factors that are beyond our control. These factors include:

- events that impact domestic and foreign supply of, and demand for, natural gas, NGLs and oil, including impacts from global health pandemics and related concerns;
- changes in weather patterns and climate, including natural disasters such as hurricanes and tornadoes;
- technological advances affecting energy consumption, storage and energy supply;
- the production levels of non-OPEC countries, including production levels in the United States' shale plays;
- United States' domestic and worldwide economic conditions;
- the price and availability of, and demand for, alternative and competing forms of energy, such as nuclear, hydroelectric, wind and solar;
- the effect of worldwide energy conservation efforts;
- the ability of the members of OPEC and other exporting nations to mutually agree to maintain oil price and production controls;
- military, economic and political conditions in natural gas and oil producing regions;
- the cost of exploring for, developing, producing, transporting and marketing natural gas, NGLs and oil; and
- domestic (federal, state and local) and foreign governmental regulations and taxation, including further legislation requiring, subsidizing or providing tax benefits for the use of alternative energy sources and fuels.

The long-term effects of these and other factors on the prices of natural gas, NGLs and oil prices are uncertain. Historical declines in natural gas and NGLs commodity prices have adversely affected our business by:

- reducing the amount of natural gas, NGLs and oil that we can economically produce;
- reducing our revenues, operating income and cash flows;
- reducing the amount of cash flows available for capital expenditures;
- increasing the cost of obtaining capital, such as equity and debt financings; and
- reducing the standardized measure of discounted future net cash flows relating to natural gas, NGLs and oil.

If demand for natural gas, NGLs and oil is reduced, the prices we receive for and our ability to market and produce our natural gas, NGLs and oil may be negatively affected. Volatility in natural gas, NGLs and oil markets and the price we receive for our production is largely determined by various factors beyond our control. Production from natural gas and oil wells in some geographic areas of the United States has been or could be curtailed for considerable periods of time due to lack of local market demand and transportation and storage capacity. In the recent past, we have temporarily shut-in wells due to low commodity prices and it is possible that some of our wells may be shut-in in the future or sales terms may be less favorable than might otherwise be obtained should demand for our products decrease and/or prices decrease. Competition for markets has been vigorous and there remains uncertainty about prices purchasers will pay or the availability of sufficient storage, all of which could have a material adverse effect on our cash flows, results of operations and financial position.

We could experience periods of higher costs. These cost increases could reduce our profitability, cash flow and ability to conduct development activities as planned. We rely on third-party contractors to provide key services and equipment for our operations. Historically, our capital and operating costs have risen during periods of increasing oil, NGLs and gas prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling and completions activity increases; and increased taxes. Increased levels of drilling activity in the natural gas and oil industry could lead to increased costs of some drilling equipment, materials and supplies. Such costs may rise faster than increases in our revenue, thereby negatively impacting our profitability, cash flow and ability to conduct development activities as planned and on budget.

Throughout 2022, we experienced cost inflation due to an increase in activity within our industry, supply chain disruptions, the Russia-Ukraine conflict and global monetary policies. We continue to undertake actions and implement plans to strengthen our supply chain to address these pressures. Nevertheless, we expect to experience supply chain constraints and inflationary pressure on our cost structure including steel, fuel and labor, among other items, for the foreseeable future. By continuing to focus on cost control initiatives and actions, which increase our drilling, completion and operating efficiencies, we are able to mitigate some inflationary pressures.

Our indebtedness could limit our ability to successfully operate our business. We are a borrower under fixed rate senior notes and maintain a bank credit facility which had a balance of $19.0 million as of December 31, 2022. Our exploration and development program requires substantial capital resources depending on the level of drilling and the expected cost of services. Existing operations also require ongoing capital expenditures. Increases in our level of indebtedness may:

- require us to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations or return of capital to stockholders;
- make us vulnerable to increases in interest rates;
- increase our vulnerability to a downturn in commodity prices or the general economy;
- place us at a competitive disadvantage compared to our competitors with lower debt service obligations;
- limit our operating flexibility due to financial and other restrictive covenants; and
- limit our flexibility to maintain or grow our business and plan for, or react to, changes in our business and the industry in which we operate.

Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. We have also engaged in asset monetization transactions; however, we may be forced to sell assets in the event capital is not available through debt or equity markets or through additional bank debt. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas, NGLs and oil and our success in developing and producing our reserves. If our access to capital were limited as a result of various factors, which could include a decrease in revenues due to lower natural gas, NGLs and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to fund our operations and replace our reserves resulting in further stress on our financial flexibility.

The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders, taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in natural gas, NGLs and oil prices adversely impact the value of our estimated proved reserves 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.

Disruptions or volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. Currently, we require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to conduct our planned operations. We are also exposed to some credit risk related to our bank credit facility to the extent that one or more of our lenders experiences liquidity problems and is unable to provide necessary funding to us under our existing revolving line of credit.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations. Our earnings and cash flow will fluctuate from year to year due to the variable nature of commodity prices. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity sales or restructure our debt. Our ability to restructure our debt will depend on the condition of the capital markets and our financial condition at such time. Any restructuring of debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our operations and our financial flexibility. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives.

We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term cash flow relative to debt balances. Liquidity, asset quality, cost structure, product mix (natural gas, NGLs and oil) and projected commodity pricing levels are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt and could require us to post letters of credit or other forms of collateral for certain obligations. For example, both Moody's and Standard and Poor's downgraded our ratings during 2020 in conjunction with an industry-wide re-rating process as a result of the prolonged downturn in commodity prices and its effects on our financial results. In both 2021 and 2022, Moody's and Standard and Poor's upgraded our ratings. We cannot provide assurance that our current ratings will remain in effect for any given period of time or that a rating will not be downgraded in the future.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part. The terms of our senior indebtedness, including our revolving credit facility, contain cross-default provisions which provide that we will be in default under such agreements in the event of certain defaults under our indentures or other loan 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.

Derivative transactions may limit our potential gains and involve other risks. To manage our exposure to commodity price volatility, we currently, and likely will in the future, enter into derivative arrangements, utilizing commodity derivatives ("hedges") with respect to a portion of our future production. Hedges are generally designed to lock in prices for commodities to limit volatility and increase the predictability of cash flow. These hedging transactions can limit our potential gains if natural gas, NGLs and oil prices rise above the price established by the hedge. In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our futures contracts fail to perform on their contract obligations; or
- an event materially impacts natural gas, NGLs or oil prices or the relationship between the hedged price index and the natural gas or oil sales prices we receive.

We cannot be certain that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, NGLs or oil. Furthermore, where we choose not to engage in derivative transactions in the future, we may be more adversely affected by decreases in natural gas, NGLs or oil prices than our competitors who utilize derivative transactions. Lower natural gas, NGLs and oil prices over a longer term will also negatively impact our ability to enter into derivative contracts at prices that exceed our costs of production.

We are exposed to a risk of financial loss if a counterparty fails to perform under a derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict such changes, our ability to mitigate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of our hedge counterparties, or some other similar proceeding or liquidity constraint, would make it unlikely 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 derivative receivable positions increase, which increases our exposure to the counterparties. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss. We do not engage in transactions involving crypto currency.

Risks related to our operations

Drilling is an uncertain and costly activity. The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough natural gas, NGLs and oil to be commercially viable after drilling, operating and other costs. There is no way to conclusively know in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs or oil in commercially viable quantities. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of a variety of factors, including, but not limited to:

- increases in the costs, shortages or delivery delays of drilling rigs, equipment, water for hydraulic fracturing services, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in natural gas, NGLs or oil prices;
- limitations in the market for natural gas, NGLs or oil;
- adverse weather conditions and changes in weather patterns;
- facility or equipment malfunctions or operator error;
- equipment failures or accidents;
- loss of title and other title-related issues;
- pipe or cement failures and casing collapses;
- compliance with, or changes in, permitting, environmental, tax and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, and unauthorized discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in geological formations;
- fires, surface craterings and explosions;
- natural disasters;
- uncontrollable flows of oil, natural gas or well fluids;
- availability and timely issuance of required governmental permits and licenses; and
- civil unrest or protest activities.

If any of these factors were to occur, we could lose all or a part of our investment or we could fail to realize the expected benefits, either of which could materially and adversely affect our revenue and profitability. Our operations involve utilizing drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- drilling the wellbore to the full planned length;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing horizontal wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Our management team has specifically identified and scheduled certain drilling locations for future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our development strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory and zoning approvals and other factors. Because of these uncertain factors, we do not know if all of the numerous drilling locations we have identified will ever be drilled. In addition, unless production is established within the spacing units covering the undeveloped acres for which some of the drilling locations are obtained, the leases for such acreage will expire. These risks are greater at times and in areas where the pace of our exploration and development activity slows. As such, our actual drilling activities may materially differ from those presently identified. In addition, we will require significant capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations and financial condition.

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies. While we have processes and procedures that we utilize to mitigate operational risks, natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids (especially those that reach surface water or groundwater), fires, pipe or cement failures, pipeline ruptures or spills, vandalism, pollution, releases of toxic gases, geological formations with abnormal or unexpected pressures, adverse weather conditions or natural disasters and other environmental hazards and risks. In addition, our operations are sometimes near populated commercial or residential areas. If any of these hazards occur, we could sustain substantial losses as a result of:

- personal injury or loss of life;
- damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- suspension of operations by regulatory authorities; and
- repairs and remediation to resume operations.

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

We may elect not to purchase insurance in instances where we determine that the cost of available insurance is excessive relative to the risks we believe are presented. However, such determinations may prove to be incorrect. Further, some forms of insurance may become unavailable in the future. If we incur 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 facilities owned and operated by third parties, in particular gas transportation and processing facilities, 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 three third-party processing plants and connecting lines for our wells in Pennsylvania where we are insured for potential catastrophic losses from the interruption of production caused by a covered loss of or damage to the processing plants; however, such insurance is limited and may not adequately protect us from all potential consequences, damages and losses.

Our producing properties are concentrated in the Pennsylvania portion of the Appalachian Basin, making us vulnerable to risks associated with operating in one geographic and political region. Essentially 100% of our total estimated proved reserves are now attributable to our properties located in the Appalachian Basin, all of which are located in Pennsylvania. We are additionally vulnerable to processing and transportation constraints for our products. For example, a significant portion of our NGLs is transported across Pennsylvania in certain pipelines which have been and continue to be the subject of state and local scrutiny and investigations, construction and flow stoppages by regulators, litigation and various fines and penalties. We are also more heavily exposed to the extensive and evolving regulatory environment in Pennsylvania which may lead to additional costs, delays or interruptions of construction, development and production from our wells. See also below *The natural gas industry is subject to extensive regulation*. Additionally, local governments in Pennsylvania are authorized to adopt and implement ordinances and impose certain restrictions regarding siting of our well sites, tanks pads and other related facilities. Approval from one or more local governmental bodies, some following a public hearing, may be required before commencing construction of our facilities which can result in delay, increased expense or in some cases, prevention of development. Moreover, new initiatives or regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of substances generated by our operations, including, but not limited to, produced water, drilling fluids and other wastes associated with our operations. Currently there are a few states that have elected to ban hydraulic fracturing altogether, including Washington, New York, Maryland, Vermont and Oregon (which temporarily suspended hydraulic fracturing until 2025); should Pennsylvania or the federal government ban hydraulic fracturing, it would preclude economic development of our Marcellus Shale reserves resulting in severe financial consequences to us.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water or dispose of or recycle water used in our operations may have a material adverse effect on our financial condition, results of operations and cash flows. Water is an essential component of our drilling and hydraulic fracturing processes. Limitation or restrictions on our ability to secure sufficient amounts of water (including limitations from natural causes such as drought) could impact our operations. If we are unable to obtain water to use in our operations from local sources, we may need to obtain from new sources and transport the water to drilling sites, resulting in increased costs. We must either dispose of or recycle water used in our operations. Compliance with environmental and permit requirements governing the withdrawal, storage and use of surface water or groundwater may increase costs and cause delays, interruptions or termination of our operations.

Our business depends on natural gas and oil transportation and NGLs processing facilities which are owned by others and depends on our ability to contract with those parties. Our ability to sell our natural gas, NGLs and oil production depends in part on the availability, proximity and capacity of gathering and transportation pipeline systems, processing facilities, rail cars, trucks or vessels owned by third parties and our ability to contract with those third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. See also above *Our producing properties are concentrated in the Pennsylvania portion of the Appalachian Basin, making us vulnerable to risks associated with operating in one geographic and political region.* Although we have some contractual control over the transportation of our products, material changes in these business relationships, including the financial condition of the contractual counterparties, could materially affect our operations. In some cases, we do not purchase firm transportation on third-party facilities and as a result, our production transportation can be interrupted by those having firm arrangements. In other cases, we have entered into firm transportation arrangements where we are obligated to pay fees on minimum volumes regardless of actual volume throughput. If production decreases due to reduced or delayed developmental activities, the current commodity price environment, production related difficulties or otherwise, we may be unable to utilize all of our rights under existing firm transportation contracts, resulting in obligations to pay fees without receiving revenue from sales. Such fees may be significant and may have a material adverse effect on our operations. We have also entered into long-term agreements with third parties to provide natural gas gathering and processing services. In some cases, the capacity of gathering systems and transportation pipelines may be insufficient to accommodate production from existing and new wells. Federal and state regulation of natural gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport natural gas, NGLs and oil. If any of these third-party pipelines or other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility change so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance, mechanical failures, accidents, weather and/or other reasons could negatively impact our ability to market and deliver our products. In particular, the disruption of certain third-party natural gas processing facilities that support our core operating area in southwest Pennsylvania could materially affect our ability to market and deliver natural gas production in that area especially if such disruption were to last for more than a short duration which could result in the necessity to curtail a significant amount of our production. We have no control over when or if such facilities are restored and generally have no control over what prices will be charged. A total shut-in of production would materially affect us due to a lack of cash flow, and if a substantial portion of the production volume is hedged at lower than market prices, our obligation to the counterparty under those financial hedges would have to be paid from borrowings thus further adversely affecting our financial condition.

Risks related to the industry in which we operate

The natural gas industry is subject to extensive regulation. Natural gas, NGLs, condensate and other hydrocarbons, as well as our operations to produce these products, are subject to extensive laws, regulations, and ordinances at the federal, state and local level. Further, new legislation, proposed rulemaking and ordinance amendments affecting the industry are under constant review for more expansive requirements and rules on our products and operations. Compliance with new and expanding laws from numerous governmental departments and agencies often increases our cost of doing business, delays our operations and decreases our profitability. Certain potential legislation, such as a ban on hydraulic fracturing, could even preclude our ability to economically develop our reserves.

Matters subject to laws and regulations affecting our business include, but are not limited to: the amount and types of substances and material that may be released into the environment, including GHGs; responding to unexpected releases of regulated substances or materials to the environment; the sourcing and disposal of water used in the drilling and completions process; permits, performance rules and reporting obligations concerning drilling, completion and production operations; threatened or endangered species and waterway protection efforts; and climate related initiatives.

Environmental regulations and pollution liability could expose us to significant costs and penalties. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies or initiatives. Some of these environmental laws and regulations may impose strict, joint and several liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred, or conditions caused by prior owners or operators or which relate to third party sites where we have taken materials for recycling or disposal. Pennsylvania law also imposes criminal liability for certain releases of substances, regardless of fault or intent. Failure to comply with these laws and regulations may result in the occurrence of delays, cancellations or restrictions in permitting or performance of our projects or other operations and subject us to administrative, civil and/or criminal penalties, corrective actions and orders enjoining some or all of our operations. Our operations may be impacted by new and amended laws and regulations and reinterpretations of existing laws and regulations or increased government enforcement relating to environmental laws. For example, properly handled drilling fluids and produced water are currently exempt from regulation as hazardous waste under RCRA, and instead are regulated under RCRA's non-hazardous waste provisions. It is possible that the EPA may in the future propose rulemaking that designates such wastes as hazardous rather than non-hazardous, and a similar designation may be made at the state level. Should this occur at the federal and/or state level it could result in significant costs to attain and maintain compliance.

We may also be exposed to liability and costs for handling of hydrocarbons, air emissions and wastewater or other fluid discharges related to our operations and waste disposal practices. Spills or other unauthorized releases of hazardous or regulated substances by us, our contractors or resulting from our operations could expose us to material losses, expenditures and liabilities, civil and criminal liabilities, under environmental laws and regulation and we are currently and have in the past been involved in such investigations, remediation and monitoring activities. The Pennsylvania Office of the Attorney General has publicly announced investigations and charges generally related to our industry in Pennsylvania. Additionally, neighboring landowners and other third parties may assert claims or file lawsuits against us for personal injury and/or property damage allegedly caused by the release of substances into the environment, with or without evidence of an impact from our operations, all of which could also result in significant litigation or settlement costs as well as reputational harm.

Laws and regulations pertaining to threatened and endangered species and protection of waterways could delay or restrict our operations and cause us to incur substantial costs. Various federal and state statutes prohibit actions or operations that adversely affect endangered or threatened species and their habitats. These statutes include the federal Endangered Species Act of 1973 ("ESA"), the Migratory Bird Treaty Act, the CWA, CERCLA and similar state programs. The United States Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in material restrictions to land use and delay, restrict or even prevent our operations. The Biden Administration has taken action to broaden enforcement under ESA, including expanding the definition of "critical habitat". While none of the species listed by FWS as threatened or endangered materially affect our operations at the present time, the future designation of previously unprotected species as threatened or endangered in areas where we conduct our operations or expansion of areas designated as "critical habitat" could cause us to incur increased costs arising from species protection measures and/or limit or prevent our ability to operate which could have an adverse effect on our ability to develop and produce reserves.

Additionally, operations may be impacted by the existence of wetlands or other environmentally sensitive areas based upon the scope of the CWA and its protection of waters of the United States. On December 30, 2022, the EPA announced a final rule related to a revised definition of "Waters of the United States" that included a broader interpretation similar to the pre-2015 definition. This final rule becomes effective 60 days after its publication in the Federal Register. Once effective, this rule may result in expansion of the CWA by the EPA or state agencies taking a more expansive view of their respective enforcement roles. The EPA may change its rules in the future. To the extent that legal challenges or any further rulemaking expands the CWA's jurisdiction we could incur increased costs and restrictions, and/or delays or cancellations in permitting or projects, which could result in significant costs and liabilities or financial losses.

Climate related regulations and initiatives could expose us to significant costs and restrictions on operations. There is an ongoing public debate as to the extent to which our climate is changing, the potential causes of climate change and its potential impacts. As part of that debate, there is also general belief that increased levels of GHGs, including carbon dioxide and methane, have contributed to and continue to contribute to climate change which has led to numerous regulatory, political, litigation and financial risks associated with the production of fossil fuels and emissions of GHGs.

Federal and state governments have from time to time considered legislation and regulations to reduce GHG emissions, including, but not limited to the implementation of GHG monitoring and reporting for the natural gas industry which includes certain of our operations. The EPA has sought to achieve these reductions under the Clean Air Act and New Source Performance Standards ("NSPS") aimed at volatile organic compounds ("VOCs") including methane emissions from oil and natural gas sources. In 2021, the EPA proposed new NSPS as part of a proposed rule to reduce methane emissions from existing oil and natural gas sources, which would (i) require states to reduce methane emissions from hundreds of thousands of existing sources nationwide for the first time, (ii) expand current emissions reductions requirements for new, modified and reconstructed sources in the oil and natural gas industry, and (iii) when finalized, require the use of advanced technologies as part of the "best system of emission reduction" for leak surveys at well sites and compressor stations. On November 11, 2022, the EPA supplemented its proposed rule regarding NSPS to, among other things, (i) ensure that all well sites are routinely monitored for leaks, with requirements based on the type and amount of equipment on site, (ii) require the deployment of innovative and advanced monitoring technologies by establishing performance requirements that can be met by a broader array of technologies, and (iii) prevent leaks from abandoned and unplugged wells by requiring documentation that well sites are properly closed and plugged before monitoring is allowed to end. A public comment period was held on the supplemented proposed rule in January 2023, with a final rule expected later in 2023. While the extent of the final rule cannot be predicted, additional costs are likely to result from compliance with proposed provisions such as expanded monitoring requirements and more stringent emissions limits. In Pennsylvania, regulators have implemented operating permits and restrictions on emissions for well site operations, compressors, processing plants and other downstream facilities that directly impact our operations. The DEP is implementing new and additional regulations to limit VOCs from existing sources for the oil and gas industry. There have also been a number of state and regional efforts that have emerged that seek to track and reduce GHG emissions by means of cap and trade programs where emitters would be required to acquire and surrender emission allowances in return for emitting GHGs. In September 2020, the PEQB approved a draft resolution to enter the Regional Greenhouse Gas Initiative ("RGGI"), a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont to cap and reduce power sector CO_2 emissions from fossil-fuel-fired electric power plants. However, in response to the PEQB's resolution to join the RGGI, the Pennsylvania General Assembly adopted a resolution on December 15, 2021, expressing its disapproval of the state's efforts to enroll in RGGI, stating that the RGGI would drive up energy costs and result in thousands of lost jobs. On January 10, 2022, Governor Wolf vetoed the disapproval resolution. In April 2022, the Pennsylvania senate failed to override Governor Wolf's veto and as a result, Pennsylvania officially joined the RGGI. However, in July 2022, the Commonwealth Court of Pennsylvania issued an order blocking the state from participating in the RGGI until the court ruled on its constitutionality. In addition to the RGGI, the DEP is evaluating other regulations to achieve the emissions reductions. We have initiated our own internal goals to reduce GHG emissions from our operations. For example, setting a goal of net zero Scope 1 and 2 GHG emissions by 2025; however, there are a variety of factors that may prevent us from meeting that goal including but not limited to operational malfunctions, availability of equipment and services, engineering results, capital constraints and availability and success of carbon offsetting initiatives. Given uncertainties related to the use of emerging technologies, the state of markets for and the availability of verified carbon offsets, we cannot predict whether or not we will be able to timely meet our net zero GHG emissions goal. Failure or a perception (whether or not valid) of failure to meet our GHG emissions goals, could damage our reputation and negatively impact our stock price.

The outcome of federal, state and regional actions to address global climate change could result in a variety of new laws and regulations to control or restrict emissions including taxes or other charges to deter or restrict emissions of GHGs. This may also depend upon political outcomes as there have been certain candidates seeking election to various state and federal offices or their appointees, who have made pledges to restrict GHG emissions, ban hydraulic fracturing of oil and natural gas wells and ban new leases for production of oil and natural gas on federal lands. Our reserves development is critically dependent upon the use of hydraulic fracturing and we cannot economically develop any of our reserves without using such technology (which we believe has been safely conducted for many decades) and a ban of such technology would result in material economic harm to us.

There are also increasing litigation risks associated with climate change concerns as a number of cities and local governments have initiated lawsuits against fossil fuel producers in state and federal court asserting claims for public nuisance and seeking damages for climate change impacts to roadways and infrastructure. Such lawsuits have also alleged that fossil fuel producers have been aware of the adverse effects of climate change and defrauded their investors by failing to adequately disclose those impacts.

Financial risks for fossil fuel energy companies, including natural gas producers, are also on the rise as stockholders and bondholders concerned about the potential effects of fossil fuels on climate change may elect to shift some or all of their investments away from fossil fuel based energy. Institutional lenders who provide financing to fossil fuel energy companies also have been under pressure from activists and are the subject of lobbying to not provide funding for fossil fuel production. Also, in November 2021, the Federal Reserve issued a statement in support of the efforts of the Network of Greening the Financial System, of which the Federal Reserve is a member, to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Some of these institutional lenders may elect not to provide funding for us which could result in restriction, delay or cancellation of drilling programs or development or production activities or impair our ability to operate economically.

Certain organizations that provide corporate governance and other corporate risk information to investors and stockholders have developed scores and ratings to evaluate companies and investment funds based on sustainability or environmental, social and governance ("ESG") metrics. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and stockholders. A number of advocacy groups, both domestically and internationally, have campaigned for governmental and private action to promote change at public companies related to ESG matters, including through investment and voting practices of investment advisors, public pension funds, universities and other members of the investing community. As a result, many investment funds focus on positive ESG business practices and sustainability scores when making investments. Companies which do not adapt to or comply with investor or stockholder ESG expectations and standards or which are perceived to have not responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, may suffer from reputational damage and the financial condition, results of operations or cash flows of such a company could be materially and adversely affected.

Moreover, we may from time-to-time create and publish voluntary disclosures regarding ESG matters. Many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

At this time, we cannot predict the potential impact of such laws, regulations, regional or international initiatives or compacts, litigation, ESG ratings or financing restrictions due to climate concerns on our future consolidated financial condition, results of operations or cash flows; however, such impacts could be material and have material negative consequences to our business.

Information concerning our reserves and future net cash flow are estimates and are not certain to match our results. There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves and their values, including many factors beyond our control. Estimates of proved reserves depend on many assumptions relating to current and future economic conditions and commodity prices as well as the projected productivity of our wells. To the extent we experience a sustained period of reduced commodity prices, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Although we utilize robust processes and procedures to evaluate and estimate our reserves, they are estimates and the actual production, revenues and costs to develop our estimated reserves will vary from estimates and these variances could be material and/or negative.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective application of engineering principles to natural gas, NGLs and oil reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of natural gas, NGLs and oil production;
- the revenues and costs associated with that production;
- the amount and timing of future development expenditures; and
- future commodity prices.

The discounted future net cash flows from our proved reserves included in this report are not the same as the market value of the reserves attributable to our properties. As required by United States generally accepted accounting principles ("U.S. GAAP"), the estimated discounted future net revenues from our proved reserves are based on a twelve month average price (first day of the month) while cost estimates are based on current year-end economic conditions. Actual future prices and costs may be materially higher or lower. In addition, the ten percent discount factor that is required to be used to calculate discounted future net cash flows for reporting purposes under U.S. GAAP is not necessarily the most appropriate discount factor based on the cost of capital, which varies from time to time, and risks associated with our business and the oil and gas industry in general.

We may face various risks associated with the long-term trend toward increased activism against oil and gas exploration and development activities. Opposition toward oil and gas drilling and development activity has been growing over time. Companies in the oil and gas industry are often the target of activist efforts to delay or prevent oil and gas development from both individuals and non-governmental organizations who use safety, environmental compliance and business practices to support their opposition to oil and gas drilling. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil and gas drilling, as well as the pipeline infrastructure needed to transport and process oil and gas production. 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 like Pennsylvania that are among the most stringent in their regulation of the industry. Such activist efforts could result in the following:

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

We may need to incur significant costs associated with responding to these initiatives and such actions may materially adversely affect our financial results. Complying with any resulting additional legal or regulatory requirements that are substantial or prevent our activity could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Conservation measures and technological advances could reduce demand for oil and natural gas. Fuel conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation or storage devices (such as battery technology) may in the future, reduce the demand for and in turn, the prices of, natural gas, NGLs and oil that we sell. In addition, these measures may reduce the availability to us of necessary third-party services and facilities that we rely on which could increase our operational costs and adversely impact our ability to produce, transport and process natural gas, NGLs and oil. The impact of changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Legal, tax and regulatory risks

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated or postponed and additional federal or state taxes or fees on natural gas extraction may be imposed including taxes or fees related to methane emissions. Legislation is periodically proposed that could make significant changes to United States federal income tax laws and could include the elimination of certain United States federal income tax benefits currently available to oil and gas exploration and production companies including, but not limited to, (i) the repeal of percentage depletion allowances for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs and; (iii) an extension of the amortization period for certain geological and geophysical expenditures. Additionally, legislation could be enacted that imposes new fees or increases the taxes on oil and natural gas extraction, which could result in increased operating costs and/or reduced consumer demand for our products. The passage of any such legislation or any other similar change in United States federal income tax law could increase costs or eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development and any such changes could have an adverse effect on our financial condition, results of operations and cash flows. As of December 31, 2022, we had a tax basis of $187.7 million related to prior year capitalized intangible drilling costs, which will be amortized over the next five years.

In 2012, Pennsylvania enacted legislation creating a tax referred to as the natural gas impact fee applicable to production in Pennsylvania, where all of our acreage is located. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. Much like a severance tax, the fee is on a sliding scale set by the Pennsylvania Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices on the last day of each month. The impact fee increases the financial burden on our operations in the Marcellus Shale. There can be no assurance that the impact fee will remain as currently structured or that additional taxes will not be imposed. From time to time, the Pennsylvania Governor and various Pennsylvania state lawmakers have proposed legislation to enact a severance tax in substitution for, or as an addition to, the impact fee already in place. The structure of and ultimate effect of any additional tax burden cannot be estimated at this time but could be material.

We may be limited in our use of net operating losses and tax credits and deductibility of business interest expense. As noted in the financial statements included with this Form 10-K, we have substantial net operating losses ("NOLs"). Utilization of these NOLs and the deductibility of business interest expense depends on many factors, including the company's future taxable income. Our ability to utilize our deferred tax assets is dependent on the amount of future pre-tax income that we are able to generate through our operations or the sale of assets. If management concludes that it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized, a valuation allowance will be recognized in the period that this conclusion is reached. In addition, limitations may exist upon use of these NOLs in the event that a change in control occurs. In either case, the impact of the valuation allowance would be negative to our financial statements.

Legal proceedings brought against us could result in substantial liabilities and materially and adversely impact our financial condition. Like many oil and gas companies, we are involved in various legal proceedings, including threatened claims, such as title, royalty, and contractual disputes. The cost to settle legal proceedings (asserted or unasserted) or satisfy any resulting judgment against us in such proceedings could result in a substantial liability or the loss of interests, which could materially and adversely impact our cash flows, operating results and financial condition. Judgments and estimates to determine accruals or range of losses related to legal proceedings could change from one period to the next, and such changes could be material. Current accruals may be insufficient to satisfy any such judgments. Legal proceedings could also result in negative publicity about Range. In addition, legal proceedings distract management and other personnel from their primary responsibilities. At this time, based on the information available to management, there are no pending claims or litigation which appear likely to result in a material financial impact. However, management's assessment of pending claims and litigation could be inaccurate and subsequent events could result in material liabilities from such claims or litigation.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel. None of our senior management team nor any of the other officers are subject to an employment agreement and therefore retaining them as employees is less certain than if they were parties to an employment agreement. The unanticipated loss of one or more of these individuals, particularly regarding our CEO, CFO and COO, could have a material adverse effect on our business. Further, the loss of key technical professionals with extensive experience in our core operating area could be difficult to replace if they were to leave and the loss of such employees could adversely affect the costs of drilling, completing and operating our wells.

Risks related to our common stock

Common stockholders will be diluted if additional shares are issued. In order to align interests and encourage ownership, we issue restricted stock and performance share units to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional senior notes or other securities or debt convertible into common stock to extend maturities or fund capital expenditures, including acquisitions. The issuance of additional shares of common stock results in dilution of the interests of existing stockholders. One way to reverse the effects of dilution is by the acquisition of our stock. However, our ability to repurchase securities for cash is limited by our bank credit facility and certain bond indentures.

Dividend limitations. Limits on the payment of dividends and other restricted payments (as defined in our bank credit facility) are imposed under our bank credit facility. These limitations may, in certain circumstances, limit or prevent the payment of dividends. In January 2020, we announced that the board of directors suspended the dividend on our common stock. However, in third quarter 2022, our board of directors reinstated our cash dividend.

Our stock price may be volatile and stockholders may not be able to resell shares of our common stock at or above the price they paid. The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2020 to December 31, 2022 the price of our common stock reported by the New York Stock Exchange ranged from a low of $1.64 per share to a high of $37.44 per share. From January 1, 2023 to February 20, 2023, our common stock ranged from a low of $22.61 per share to a high of $27.01 per share. We expect our stock price to continue to be subject to volatility as a result of a variety of factors, including factors beyond our control. These factors include:

- most significantly, changes in natural gas, NGLs and oil prices;
- variations in drilling, recompletions, acquisitions and operating results;
- changes in governmental regulation and/or taxation;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- expectations regarding our capital program, including any determination by our board of directors regarding repurchasing stock or paying dividends;
- changes in key personnel; or
- future sales of additional stock and changes in our capital structure.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future and our stock price could decline as a result.

General risk factors

Our business could be negatively affected by security threats, including cybersecurity threats and other disruptions. The United States government has issued public warnings that indicate that energy assets might be specific targets of cybersecurity threats. As a natural gas and oil producer, we face various security threats, including:

- cybersecurity threats to gain unauthorized access to sensitive information or to render data or computer systems unusable;
- threats to the security or operations at our physical facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; or
- threats from terrorist acts.

Computers and telecommunication systems are an integral part of our business and are used to support our exploration, development and production activities and our key accounting and financial reporting functions. We use these systems to analyze and store financial and operating data and to communicate internally and with outside business counterparties. Cyberattacks could compromise our computer and telecommunications systems and result in disruptions to our business operations or the loss of our data and proprietary information. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A cyberattack against these operating systems, or the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, cause accidental discharge and/or make it difficult or impossible to accurately account for production and settle transactions. A cyberattack on a vendor or a service provider could result in supply chain disruptions, which could delay or halt development projects. A cyberattack on our accounting or human resources systems could expose us to liability if personal information is obtained.

Security threats have subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our personnel, information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to harm to our employees or losses of sensitive information, losses of critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, and results of operations or cash flows. Attackers are becoming more sophisticated and both the frequency and magnitude of cyberattacks in particular are expected to increase and include, but are not limited to, malicious software, phishing, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage our reputation and lead to financial losses from unauthorized disbursement of funds, remedial actions, loss of business and/or potential liability. We may be unable to anticipate, detect or prevent future attacks, particularly as methodologies utilized by attackers change frequently and are not recognized until launched. Additionally, the continuing and evolving threat of cybersecurity attacks has resulted in evolving legal and compliance matters, including increased regulatory focus on prevention, which could require us to expend significant additional resources to meet such requirements. While we utilize extensive processes and procedures that we deem appropriate to counter cybersecurity risks and to date have not suffered any material losses relating to such attacks, there can be no assurance that we will not suffer such losses in the future. Any losses, costs or liabilities directly or indirectly related to cyberattacks or similar incidents may not be covered by, or may exceed the coverage limits of, any of our insurance policies.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in areas around the world and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism and, in turn, could materially and adversely affect our business and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We will continue to evaluate our litigation quarterly and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then-current status of litigation.

Environmental Proceedings

From time to time, we receive notices of violation from governmental and regulatory authorities in areas in which we operate relating to alleged violations of environmental statutes or the rules and regulations promulgated thereunder. While we cannot predict with certainty whether these notices of violation will result in fines and/or penalties, if fines and/or penalties are imposed, they may result in monetary sanctions, individually or in the aggregate, in excess of $250,000.

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

Market for Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "RRC". During 2022, trading volume averaged approximately 5.0 million shares per day.

Holders of Record

Pursuant to the records of our transfer agent, as of February 20, 2023, there were approximately 873 holders of record of our common stock.

Dividends

The payment of dividends is subject to the formal declaration by the board of directors. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our board of directors and will depend upon, among other things, our earnings, financial condition, capital requirements, levels of indebtedness and other considerations our board of directors deems relevant. For more information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Equity Compensation Plan Information

The information required by this item is incorporated herein by reference to the 2023 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2022.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

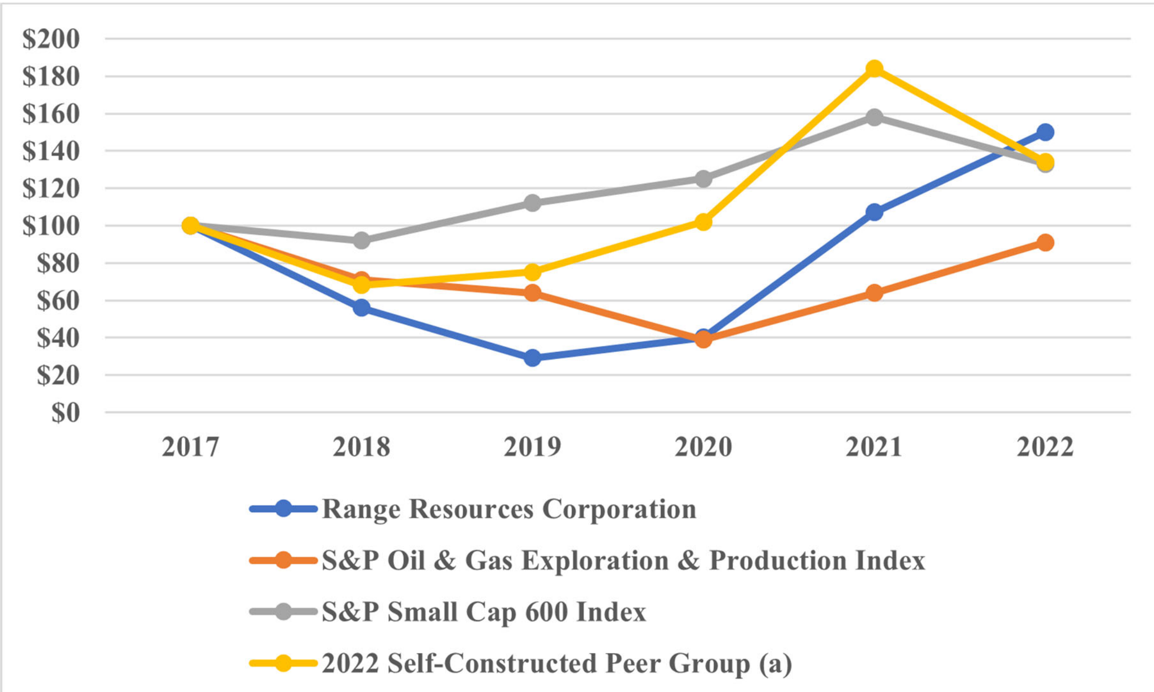
Purchases of our common stock are as follows:

	Three Months Ended December 31, 2022			
Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased Under Plans or Programs [(a)]
October 2022	540,000	$ 27.72	540,000	$ 1,171,161,132
November 2022	1,040,000	$ 27.58	1,040,000	$ 1,142,476,809
December 2022	1,610,000	$ 26.13	1,610,000	$ 1,100,400,840
	3,190,000		3,190,000	

(a) In October 2019, our board of directors authorized a $100 million common stock repurchase program. In February 2022, our board of directors subsequently increased the authorization under the program for a cumulative approval of $530.0 million. In October 2022, the board of directors authorized an additional repurchase of up to $1.0 billion of outstanding common stock under the program, which includes fees, commissions and expenses. As of December 31, 2022, these repurchased shares are held as treasury stock.

Stockholder Return Performance Presentation

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of Range's common stock, the S&P Oil and Gas Exploration and Production Index, and the S&P Small Cap 600 Index. We have added a self-constructed Peer Group that matches the peer group selected by our Compensation Committee of the board of directors and is used in our performance unit program along with deleting three indexes which include the S&P Mid Cap 400 Index, the Dow Jones U.S. Exploration & Production Index and the ISE Revere National Gas Index. We believe these changes more accurately provide a broader comparison of stock performance along with using indexes that are most commonly used in our industry or indexes in which we are included. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2017 and that dividends were reinvested.



	2017	2018	2019	2020	2021	2022
Range Resources Corporation	$ 100	$ 56	$ 29	$ 40	$ 107	$ 150
S&P Oil & Gas Exploration & Production Index	100	71	64	39	64	91
S&P Small Cap 600 Index	100	92	112	125	158	133
2022 Self-Constructed Peer Group [a]	100	68	75	102	184	134

[a] The 2022 Self-Constructed Peer Group includes the following twelve companies: Antero Resources Corporation, Chesapeake Energy Corporation, CNX Resources, Comstock Resources, Inc., Coterra Energy, Inc., EQT Corporation, Matador Resources, Murphy Oil, PDC Energy, SM Energy Company, Southwestern Energy Company and the S&P 500 and is weighted based on stock market capitalization.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition and should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and other financial information found elsewhere in this Form 10-K. See also matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements."

The following tables and discussions set forth key operating and financial data for the years ended December 31, 2022 and 2021. For similar discussions of the year ended December 31, 2021 compared to December 31, 2020 results, refer to Item 7. "Managements' Discussion and Analysis of Financial Condition and Results of Operations" under Part II of our annual report on Form 10-K for the year ended December 31, 2021, which was filed with the SEC on February 22, 2022.

Overview of Our Business

We are an independent natural gas, natural gas liquids ("NGLs,") crude oil and condensate company engaged in the exploration, development and acquisition of natural gas and crude oil properties located in the Appalachian region of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our overarching business objective is to build stockholder value through returns-focused development of natural gas properties. Our strategy to achieve our business objective is to generate consistent cash flows from reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions and divestitures of non-core or, at times, core assets. Currently, our investment portfolio is focused on high quality natural gas assets in the state of Pennsylvania. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs, crude oil and condensate and on our ability to economically find, develop, acquire and produce natural gas, NGLs and oil reserves.

Commodity prices have been and are expected to remain volatile. We believe we are well-positioned to manage any challenges during a low commodity price environment and that we can endure the continued volatility in current and future commodity prices by:

- exercising discipline in our capital investments;
- continuing to optimize drilling, completion and operational efficiencies;
- remaining focused on maintaining a competitive cost structure;
- continuing to manage price risk through the hedging of our production; and
- continuing to manage our balance sheet.

Prices for natural gas, NGLs, crude oil and condensate fluctuate widely and affect:

- our revenues, profitability and cash flow;
- the quantity of natural gas, NGLs and oil that we can economically produce;
- the quantity of natural gas, NGLs and oil shown as proved reserves;
- the amount of cash flow available to us for capital expenditures; and
- our ability to borrow and raise additional capital.

We prepare our financial statements in conformity with U.S. GAAP, which require us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved natural gas, NGLs and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located in Fort Worth, Texas.

Key 2022 highlights include:

Enhanced the balance sheet, increased return of capital to investors and preserved liquidity

- In first quarter 2022, we issued an aggregate principal amount of $500.0 million in new 4.75% senior notes due 2030 and used the proceeds to redeem $850.0 million of our 9.25% senior notes due 2026 at a premium. In addition, in mid-December 2022, we redeemed the remaining 5.0% senior notes due 2023 at par. As of December 31, 2022, we had $19.0 million borrowed under our bank credit facility, $207,000 of cash on hand and $1.2 billion available under our bank credit facility. The table below details the changes in our outstanding debt principal balances from December 31, 2021 to December 31, 2022 (in thousands):

	December 31, 2021	Change	December 31, 2022
Bank debt	$ —	$ 19,000	$ 19,000
Senior notes			
4.75% senior notes due 2030	—	500,000	500,000
5.00% senior notes due 2022	169,589	(169,589)	—
5.875% senior notes due 2022	48,528	(48,528)	—
5.00% senior notes due 2023	532,335	(532,335)	—
4.875% senior notes due 2025	750,000	—	750,000
9.25% senior notes due 2026	850,000	(850,000)	—
8.25% senior notes due 2029	600,000	—	600,000
Total senior notes	2,950,452	(1,100,452)	1,850,000
Total debt	2,950,452	(1,081,452)	1,869,000
Cash balance (as disclosed on balance sheet)	(214,422)	214,215	(207)
Total debt, net of cash	$ 2,736,030	$ (867,237)	$ 1,868,793

- Our banks' committed borrowing capacity remained at $1.5 billion after completing our semi-annual borrowing base redetermination in September 2022.
- Our next significant long-term debt maturity is $750.0 million due in 2025.
- Increased return of capital to investors by:
  - Repurchasing $399.7 million of our common stock (14.0 million shares) in 2022 via the share repurchase program; and
  - Distributing dividends totaling $38.6 million.

Improved financial and operational results

- Significant increases in realized prices resulted in:
  - An increase of $1.7 billion of natural gas, NGLs and oil revenues when compared to 2021; and
  - An additional loss on commodity derivatives settled of $670.0 million when compared to 2021.
- Our diluted net income per share was $4.69 in 2022 compared to $1.61 in 2021.
- Cash provided by operating activities was $1.9 billion, an increase of $1.1 billion when compared to 2021.
- Delivered strong operational execution along with focusing on cost control and managing cost inflation while emphasizing safety and protection of the environment.
- Increased proved reserves to 18.1 Tcfe, 2% higher than 2021.

Continued to focus on safe, responsible and sustainable operations

- Continued to recycle approximately 100% of produced water.
- Increased leak detection inspections to eight times a year.
- Pilot tested the use of compressed air pneumatic controllers.
- Achieved a 50% reduction in number of workforce recordable injuries with a Total Recordable Incident Rate of 0.46.
- Achieved a 50% reduction in number of workforce days away restricted treatment injuries with a DART of 0.11.

Management's Discussion and Analysis of Results of Operations

Commodity prices have remained volatile. Benchmarks for natural gas, oil and NGLs increased in 2022 compared to 2021 and, as a result, we experienced significant increases in our price realizations when compared to the same period of 2021. We had many operational, financial and strategic successes in 2022 as we continued to focus on enhancing margins and returns, driving operational efficiencies and returning capital to stockholders. We believe we have positioned ourselves for long-term success through the commodity price cycles.

Overview of 2022 Results

For the year ended December 31, 2022, we experienced an increase in revenue from the sale of natural gas, NGLs and oil due to a 65% increase in net realized prices (average prices including all derivative settlements and third-party transportation costs paid by us) when compared to 2021. Daily production in 2022 averaged 2.12 Bcfe compared to 2.13 Bcfe in 2021. Average natural gas differentials were below NYMEX and slightly lower than the prior year.

During 2022, we recognized net income of $1.2 billion, or $4.69 per diluted common share compared to $411.8 million, or $1.61 per diluted common share during 2021. The improvement in net income for the year ended December 31, 2022 when compared to 2021 is due to significantly higher realized prices.

During 2022, our financial and operating performance included the following results:

- reduced total debt $1.1 billion and issued $500.0 million of new 4.75% senior notes which were used to refinance a portion of our 8.25% senior notes;
- increased cash flow from operating activities by 135% from the same period of 2021;
- drilled 59 net wells with a 100% success rate;
- continued development of our Marcellus Shale inventory by maintaining production, proving up acreage and acquiring additional unproved acreage;
- increased revenue from the sale of natural gas, NGLs and oil by 53% from the same period of 2021 with a 53% increase in average realized prices (before cash settlements on our derivatives);
- increased revenue from the sale of natural gas, NGLs and oil (including settlements on our derivatives) by 39% from the same period of 2021;
- increased direct operating expense per mcfe 10%, or 0.01 per mcfe from 2021;
- held general and administrative expenses per mcfe flat when compared to 2021;
- reduced our DD&A rate per mcfe 2% from 2021;
- entered into additional commodity-based derivative contracts for 2023 through 2026; and
- ended the year with cash on hand of $207,000 and stockholders' equity of $2.9 billion.

We generated $1.9 billion of cash flow from operating activities in 2022, an increase of $1.1 billion from 2021 which reflects significantly higher realized prices and lower comparative working capital outflows ($169.3 million outflow during 2022 compared to $241.7 million outflow in 2021). We ended 2022 with $1.2 billion of available committed borrowing capacity.

Acquisitions

During 2022, we invested $28.7 million to acquire unproved acreage compared to $22.0 million in 2021. We continue selective acreage leasing and lease renewals to consolidate our acreage positions in the Marcellus Shale play in Pennsylvania.

2023 Outlook

As we enter 2023, we believe we are positioned for sustainable long-term success. For 2023, we expect our capital budget to be in the range of $570.0 million to $615.0 million for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. We expect our 2023 capital budget to achieve production similar to our 2022 production. Our 2023 capital budget is designed to focus on continuing to improve corporate returns and generating free cash flow and we expect it to be funded with operating cash flow. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2023 is partially mitigated by entering into commodity derivative contracts and we intend to continue to enter into these types of contracts. We believe it is likely that commodity prices will continue to be volatile during 2023. We also expect inflationary pressures, which ultimately depend on various factors beyond our control, to continue during 2023. We continue to assess and monitor the impact and consequences of this on our operations.

Market Conditions

Prices for natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Natural gas, NGLs and oil benchmarks increased in 2022 when compared to the same period of 2021 and, as a result, we experienced a significant increase in price realizations. As we continue to monitor the impact of the actions of OPEC and other large producing nations, the Russia-Ukraine conflict, global inventories of oil and gas and the uncertainty associated with potential recession on oil demand, future monetary policy and governmental policies aimed at transitioning towards lower carbon energy, we expect prices for some or all of the commodities we produce to remain volatile. Futures prices have declined based on the relatively mild winter and infrastructure constraints. Longer term natural gas futures prices remain strong based on market expectations that associated gas related activity in oil basins and dry gas basin activity will show modest rates of growth compared with the past due to infrastructure constraints, capital discipline and core inventory exhaustion. In addition, the global energy crisis further highlighted the low cost and low emissions shale gas resource base in North America, supporting continued strong structural demand growth for United States liquefied natural gas exports, domestic industrial gas demand and power generation. Other factors such as the pace and extent of tightening global monetary policy and the effectiveness of responses to combat the COVID-19 virus may impact the recovery of world economic growth and the demand for oil, natural gas and NGLs. In addition, in response to continued supply chain disruptions attributable to the virus, the Russia-Ukraine conflict and global monetary policies over the last few years, cost inflation is occurring. We continue to assess and monitor the impact and consequences of these factors on our operations.

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. Recently, natural gas prices have decreased, when compared to December 2022, with the average NYMEX monthly settlement price for natural gas decreasing to $3.11 per mcf for February 2023 with the recent mild winter weather. Crude oil prices have increased, when compared to December 2022, to $78.16 per barrel in January 2023. The following table lists related benchmarks for natural gas, oil and NGLs composite prices for the years ended December 31, 2022 and 2021.

	Year Ended December 31,	
	2022	2021
Benchmarks:		
Average NYMEX prices [(a)]		
Natural gas (per mcf)	$ 6.64	$ 3.88
Oil (per bbl)	$ 94.90	$ 67.93
Mont Belvieu NGLs composite (per gallon) [(b)]	$ 0.90	$ 0.74

[(a)] Based on average of monthly last day settlement prices on the New York Mercantile Exchange (“NYMEX”).
[(b)] Based on our estimated NGLs product composition per barrel.

Our price realizations (not including the impact of our derivatives) may differ from the benchmarks for many reasons, including quality, location, or production being sold at different indices.

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. In 2022, natural gas, NGLs and oil sales increased 53% from 2021 with a 53% increase in realized prices (excluding cash settlements on our derivatives). The following table illustrates the primary components of natural gas, NGLs, crude oil and condensate sales for the last two years (in thousands):

	Year Ended December 31,			
	2022	2021	Change	% Change
Natural gas, NGLs and Oil sales				
Natural gas	$ 3,364,111	$ 1,896,231	$ 1,467,880	77%
NGLs	1,308,574	1,135,826	172,748	15%
Oil and condensate	238,407	182,970	55,437	30%
Total natural gas, NGLs and oil sales	$ 4,911,092	$ 3,215,027	$ 1,696,065	53%

Production is maintained through drilling success as we place new wells on production which is partially offset by the natural decline of our natural gas and oil reserves through production. Our production for the last two years is set forth in the following table:

	Year Ended December 31,			
	2022	2021	Change	% Change
Production [a]				
Natural gas (mcf)	539,442,624	541,021,442	(1,578,818)	—%
NGLs (bbls)	36,392,033	36,372,862	19,171	—%
Crude oil and condensate (bbls)	2,715,681	3,044,026	(328,345)	(11%)
Total (mcfe) [b]	774,088,908	777,522,772	(3,433,864)	—%
Average daily production [a]				
Natural gas (mcf)	1,477,925	1,482,251	(4,326)	—%
NGLs (bbls)	99,704	99,652	52	—%
Crude oil and condensate (bbls)	7,440	8,340	(900)	(11%)
Total (mcfe) [b]	2,120,792	2,130,199	(9,407)	—%

(a) Represents volumes sold regardless of when produced.

(b) Oil and NGLs volumes are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship between oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) received during 2022 was $3.17 per mcfe compared to $1.92 per mcfe in 2021. The majority of our production is sold at market-sensitive prices. Generally, if the related commodity index declines, the price we receive for our production will also decline. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices should include the impact of transportation, gathering, processing and compression expense. Average sales prices (excluding derivative settlements) do not include any derivative settlements or third-party transportation costs which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales prices (excluding derivative settlements) do include transportation costs where we receive net proceeds from the purchaser. Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) calculation includes all cash settlements for derivatives. Our derivative settlements included in our realized price calculations do not include settlements of contingent consideration related to the sale of our North Louisiana properties. Average realized price calculations for the last two years are shown below:

	Year Ended December 31,			
	2022	2021	Change	% Change
Average Prices				
Average sales prices (excluding derivative settlements):				
Natural gas (per mcf)	$ 6.24	$ 3.50	$ 2.74	78%
NGLs (per bbl)	35.96	31.23	4.73	15%
Crude oil (per bbl)	87.79	60.11	27.68	46%
Total (per mcfe) [a]	6.34	4.13	2.21	53%
Average realized prices (including all derivative settlements):				
Natural gas (per mcf)	$ 4.16	$ 2.74	$ 1.42	52%
NGLs (per bbl)	35.62	28.70	6.92	24%
Crude oil (per bbl)	57.39	46.16	11.23	24%
Total (per mcfe) [a]	4.78	3.43	1.35	39%
Average realized prices (including all derivative settlements and third-party transportation costs paid by Range):				
Natural gas (per mcf)	$ 2.90	$ 1.51	$ 1.39	92%
NGLs (per bbl)	20.08	14.64	5.44	37%
Crude oil (per bbl)	57.39	45.86	11.53	25%
Total (per mcfe) [a]	3.17	1.92	1.25	65%

(a) Oil and NGLs volumes are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Realized prices include the impact of basis differentials and gains or losses realized from our basis hedging. The prices we receive for our natural gas can be more or less than the NYMEX price because of adjustments for delivery location, relative quality and other factors. The following table provides this impact on a per mcf basis:

	Year Ended December 31,	
	2022	2021
Average natural gas differentials below NYMEX	$ (0.40)	$ (0.38)
Realized gains on basis hedging	$ 0.11	$ 0.04

The following tables reflect our production and average realized commodity prices (excluding derivative settlements and third-party transportation costs paid by Range) (in thousands, except prices):

	Year Ended December 31,			
	2021	Price Variance	Volume Variance	2022
Natural gas				
Price (per mcf)	$ 3.50	$ 2.74	$ —	$ 6.24
Production (Mmcf)	541,021	—	(1,578)	539,443
Natural gas sales	$ 1,896,231	$ 1,473,414	$ (5,534)	$ 3,364,111

	Year Ended December 31,			
	2021	Price Variance	Volume Variance	2022
NGLs				
Price (per bbl)	$ 31.23	$ 4.73	$ —	$ 35.96
Production (Mbbls)	36,373	—	19	36,392
NGLs sales	$ 1,135,826	$ 172,150	$ 598	$ 1,308,574

	Year Ended December 31,			
	2021	Price Variance	Volume Variance	2022
Crude oil				
Price (per bbl)	$ 60.11	$ 27.68	$ —	$ 87.79
Production (Mbbls)	3,044	—	(328)	2,716
Crude oil sales	$ 182,970	$ 75,173	$ (19,736)	$ 238,407

	Year Ended December 31,			
	2021	Price Variance	Volume Variance	2022
Consolidated				
Price (per mcfe)	$ 4.13	$ 2.21	$ —	$ 6.34
Production (Mmcfe)	777,523	—	(3,434)	774,089
Total natural gas, NGLs and oil sales	$ 3,215,027	$ 1,710,264	$ (14,199)	$ 4,911,092

Transportation, gathering, processing and compression expense was $1.2 billion in 2022 and in 2021. These third-party costs are slightly higher due to the impact of higher NGLs prices which result in higher processing costs, higher fuel costs and higher electricity costs partially offset by the expiration of certain demand charges in our northeast Pennsylvania properties. We have included these costs in the calculation of average realized prices (including all derivative settlements and third-party transportation expenses paid by Range). The following table summarizes transportation, gathering, processing and compression expense for the last two years (in thousands) and on a per mcf and per barrel basis:

	Year Ended December 31,			
	2022	2021	Change	% Change
Natural gas	$ 677,316	$ 661,990	$ 15,326	2%
NGLs	565,614	511,568	54,046	11%
Oil	11	911	(900)	(99%)
Total	$ 1,242,941	$ 1,174,469	$ 68,472	6%
Natural gas (per mcf)	$ 1.26	$ 1.22	$ 0.04	3%
NGLs (per bbl)	$ 15.54	$ 14.06	$ 1.48	11%
Oil (per bbl)	$ —	$ 0.30	$ (0.30)	(100%)

Derivative fair value (loss) income was a loss of $1.2 billion in 2022 compared to a loss of $650.2 million in 2021. All of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from derivatives are included in total revenues. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate lower wellhead revenues in the future while losses indicate higher future wellhead revenues. At December 31, 2022, our commodity derivative contracts were recorded at their fair value, which was a net derivative liability of $138.6 million, a decrease of $30.9 million from the $169.5 million net derivative liability recorded as of December 31, 2021. We have also entered into basis swap agreements to limit volatility caused by changing differentials between NYMEX and regional prices received. These basis swaps are marked to market and we recognized a net derivative asset of $521,000 as of December 31, 2022 compared to a net derivative asset of $16.0 million as of December 31, 2021. The following table summarizes the impact of our commodity derivatives for the last two years (in thousands):

	Year Ended December 31,	
	2022	2021
Derivative fair value loss per consolidated statements of operations	$ (1,188,506)	$ (650,216)
Non-cash fair value (loss) gain: [(1)]		
Natural gas derivatives	$ (2,392)	$ (130,114)
Oil derivatives	14,783	(23,879)
NGLs derivatives	2,931	14,100
Freight derivatives	(114)	(990)
Contingent consideration	(13,560)	10,680
Total non-cash fair value gain (loss) [(1)]	$ 1,648	$ (130,203)
Net cash (payment) receipt on derivative settlements:		
Natural gas derivatives	$ (1,119,940)	$ (415,228)
Oil derivatives	(82,546)	(42,447)
NGLs derivatives	(12,168)	(91,838)
Contingent consideration	24,500	29,500
Total net cash payment	$ (1,190,154)	$ (520,013)

(1) Non-cash fair value adjustments on commodity derivatives is a non-GAAP measure. Non-cash fair value adjustments on commodity derivatives only represent the net change between periods of the fair market values of commodity derivative positions and exclude the impact of settlements on commodity derivatives during the period. We believe that non-cash fair value adjustments on commodity derivatives is a useful supplemental disclosure to differentiate non-cash fair market value adjustments from settlements on commodity derivatives during the period. Non-cash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered a substitute for derivative fair value income or loss as reported in our consolidated statements of operations.

Brokered natural gas, marketing and other revenue was $424.2 million in 2022 compared to $365.4 million in 2021. We enter into purchase transactions with third parties and separate sale transactions with third parties at different times to utilize available pipeline capacity and to fulfill sales commitments in the event of operational upsets. The 2022 period includes $408.6 million of revenue from the sale of natural gas that is not related to our production (brokered) and $2.8 million of revenue from the sale of NGLs that is not related to our production. The 2021 period includes $342.4 million of revenue from the brokered sale of natural gas and $6.9 million of revenue from the sale of NGLs that is not related to our production. These revenues increased compared to 2021 due to higher sales prices partially offset by lower brokered volumes. The twelve months ended December 31, 2021 also includes $8.8 million received as part of a capacity release agreement.

Costs and Expenses per mcfe

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for the last two years:

	Year Ended December 31,			
	2022	2021	Change	% Change
Direct operating expense	$ 0.11	$ 0.10	$ 0.01	10%
Taxes other than income expense	0.05	0.04	0.01	25%
General and administrative expense	0.22	0.22	—	—%
Interest expense	0.21	0.29	(0.08)	(28%)
Depletion, depreciation and amortization expense	0.46	0.47	(0.01)	(2%)

Direct operating expense was $84.3 million in 2022 compared to $75.3 million in 2021. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repair-related expenses. On an absolute basis, our direct operating expenses for 2022 increased 12% from the prior year primarily due to higher water hauling/handling costs and higher contract labor costs. We incurred $3.0 million of workover costs in 2022 compared to $3.4 million of workover costs in 2021.

On a per mcfe basis, operating expense for 2022 increased $0.01, or 10% from the same period of 2021, with the increase due to higher water hauling/handling costs. Stock-based compensation expense represents the amortization of equity grants as part of the compensation of field employees. The following table summarizes direct operating expenses per mcfe for the last two years:

	Year Ended December 31,			
	2022	2021	Change	% Change
Lease operating expense	$ 0.11	$ 0.10	$ 0.01	10%
Workovers	—	—	—	—%
Stock-based compensation	—	—	—	—%
Total direct operating expense	$ 0.11	$ 0.10	$ 0.01	10%

Taxes other than income expense was $35.4 million in 2022 compared to $30.6 million in 2021. This expense category is primarily the Pennsylvania impact fee. In 2012, Pennsylvania enacted an “impact fee” on unconventional natural gas and oil production which includes the Marcellus Shale. The impact fee is based upon the year wells are drilled and the fee varies, like a severance tax, based upon natural gas prices. The year ended December 31, 2022 includes a $33.2 million impact fee compared to $29.3 million in the year ended December 31, 2021 with the increase primarily due to higher natural gas prices. This category also includes other taxes such as franchise, real estate and commercial activity taxes. The following table summarizes taxes other than income per mcfe for the last two years:

	Year Ended December 31,			
	2022	2021	Change	% Change
Impact fee	$ 0.04	$ 0.04	$ —	—%
Other	0.01	—	0.01	—%
Total taxes other than income	$ 0.05	$ 0.04	$ 0.01	25%

General and administrative expense was $168.1 million for 2022 compared to $168.4 million for 2021. The decrease in 2022, when compared to 2021, is primarily due to lower legal expenses and legal settlements of $11.6 million offset by higher stock-based compensation and higher general office expenses including technology and insurance costs along with slightly higher salaries and benefits. As of December 31, 2022, the number of general and administrative employees increased 3% when compared to December 31, 2021.

On a per mcfe basis, general and administrative expense for 2022 was the same when compared to the same period of 2021. Lower legal expenses and legal settlements were offset by higher stock-based compensation. Stock-based compensation expense represents the amortization of stock-based compensation awards granted to our employees and our non-employee directors as part of their compensation. The following table summarizes general and administrative expenses per mcfe for the last two years:

	Year Ended December 31,			
	2022	2021	Change	% Change
General and administrative	$ 0.16	$ 0.17	$ (0.01)	(6%)
Stock-based compensation	0.06	0.05	0.01	20%
Total general and administrative expense	$ 0.22	$ 0.22	$ —	—%

Interest expense was $165.1 million for 2022 compared to $227.3 million for 2021. The following table presents information about interest expense per mcfe for the last two years:

	Year Ended December 31,			
	2022	2021	Change	% Change
Bank credit facility	$ 0.01	$ 0.02	$ (0.01)	(50%)
Senior notes	0.19	0.26	(0.07)	(27%)
Amortization of deferred financing costs and other	0.01	0.01	—	—%
Total interest expense	$ 0.21	$ 0.29	$ (0.08)	(28%)
Average debt outstanding (in thousands)	$ 2,510,107	$ 3,100,067	$ (589,960)	(19%)
Average interest rate [(a)]	6.25%	7.0%	(0.75)%	(11%)

[(a)] Includes commitment fees but excludes amortization of debt issue costs.

On an absolute basis, the decrease in interest expense for 2022 from 2021 was primarily due to lower overall average interest rates and lower outstanding average debt balances. See Note 7 to our consolidated financial statements for additional information. Average debt outstanding on the bank credit facility for 2022 was $48.4 million compared to $144.9 million for 2021 and the weighted average interest rate on the bank credit facility was 4.1% for 2022 compared to 2.1% in 2021.

Depletion, depreciation and amortization ("DD&A") was $353.4 million in 2022 compared to $364.6 million in 2021. The decrease in 2022 when compared to 2021 is due to a 2% decrease in depletion rates. On a per mcfe basis, DD&A decreased to $0.46 in 2022 compared to $0.47 in 2021. Depletion expense, the largest component of DD&A, was $0.45 per mcfe in 2022 compared to $0.46 per mcfe in 2021. We have historically adjusted our depletion rates in the fourth quarter of each year based on our year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs. We currently expect our DD&A rate to be approximately $0.45 per mcfe in 2023. The following table summarizes DD&A expenses per mcfe for the last two years:

	Year Ended December 31,			
	2022	2021	Change	% Change
Depletion and amortization	$ 0.45	$ 0.46	$ (0.01)	(2%)
Accretion and other	0.01	0.01	—	—%
Total DD&A expenses	$ 0.46	$ 0.47	$ (0.01)	(2%)

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, brokered natural gas and marketing, exploration expense, abandonment and impairment of unproved properties, exit and termination costs, deferred compensation plan and loss on early extinguishment of debt. The following table details stock-based compensation that is allocated to functional expense categories for the last two years (in thousands):

	2022	2021
Direct operating expense	$ 1,459	$ 1,310
Brokered natural gas and marketing expense	2,439	1,794
Exploration expense	1,578	1,507
General and administrative expense	42,023	39,673
Total stock-based compensation	$ 47,499	$ 44,284

Stock-based compensation includes the amortization of restricted stock and performance-based grants.

Brokered natural gas and marketing expense was $427.0 million in 2022 compared to $367.3 million in 2021. We enter into purchase transactions with third parties and separate sale transactions with third parties at different times to utilize available pipeline capacity and fulfill sales commitments in the event of operational upsets. The increase in these costs reflects higher purchase prices partially offset by lower purchased volumes. The following table details our brokered natural gas, marketing and other net margin which includes the net effect of these third-party transactions for the two-year period ended December 31, 2022 (in thousands):

	2022	2021
Brokered natural gas sales	$ 408,584	$ 342,431
Brokered NGLs sales	2,783	6,925
Other marketing revenue and other income	12,850	16,056
Brokered natural gas purchases and transportation	(413,911)	(350,426)
Brokered NGLs purchases	(2,808)	(8,044)
Other marketing expense	(10,329)	(8,818)
Net brokered natural gas and marketing margin	$ (2,831)	$ (1,876)

Exploration expense was $26.8 million in 2022 compared to $23.6 million in 2021. Exploration expense in 2022 was higher when compared to the prior year due to higher delay rentals and other costs. Stock-based compensation represents the amortization of equity stock grants as part of the compensation of our exploration staff. The following table details our exploration related expenses for the last two years (in thousands):

	Year Ended December 31,			
	2022	2021	Change	% Change
Seismic	$ 237	$ 129	$ 108	84%
Delay rentals and other	19,576	16,597	2,979	18%
Personnel expense	5,381	5,322	59	1%
Stock-based compensation expense	1,578	1,507	71	5%
Total exploration expense	$ 26,772	$ 23,555	$ 3,217	14%

Abandonment and impairment of unproved properties was $28.6 million in 2022 compared to $7.2 million in 2021. These costs increased when compared to the same period of 2021 due to higher estimated lease expirations in Pennsylvania. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property.

Exit costs in 2022 were $70.3 million compared to $21.7 million in 2021. In August 2020, we completed the sale of our North Louisiana operations in a transaction that included the retention of certain related gathering, transportation and processing obligations extending until 2030. The present value of these estimated future obligations totaled $479.8 million which was recorded in third quarter 2020. In the twelve months ended December 31, 2022, we recorded $43.6 million accretion expense related to retained liabilities and in second quarter 2022, we recorded an unfavorable adjustment of $24.8 million to increase this obligation for a change in the forecasted drilling plans of the buyer. In the twelve months ended December 31, 2021, we recorded $48.7 million accretion expense related to retained liabilities and in second quarter 2021, we recorded a gain of $28.2 million to reduce our original estimate of these retained obligations due to payments being lower than our forecast partially offset by a change in the forecasted drilling plans of the buyer. The following table details our exit and termination costs for the last two years (in thousands):

	Year Ended December 31,	
	2022	2021
Divestiture contract obligation (including accretion of discount)	$ 69,758	$ 20,340
Transportation contract capacity releases (including accretion of discount)	579	754
Severance costs	—	567
	$ 70,337	$ 21,661

Deferred compensation plan expense was $61.9 million in 2022 compared to $68.4 million in 2021. Our stock price increased to $25.02 at December 31, 2022 from $17.83 at December 31, 2021. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Common shares are placed in the deferred compensation plan when granted to eligible participants.

Loss on early extinguishment of debt was $69.5 million in 2022 compared to $98,000 in 2021. In first quarter 2022, we announced a call for the redemption of $850.0 million of our outstanding 9.25% senior notes due 2026 which were redeemed on February 1, 2022. The redemption price equaled 106.938% of par plus accrued and unpaid interest. We recognized a loss on early extinguishment of debt of $69.2 million, including transaction call premium costs and the expensing of the remaining deferred financing costs on the repurchased debt.

Income tax expense (benefit) was an expense of $230.5 million in 2022 compared to a benefit of $9.7 million in 2021. The 2022 increase in the income tax expense reflects a $1.0 billion improvement in our operating income before income taxes when compared to 2021 partially offset by changes in our valuation allowances due to our results and the current commodity price environment. The effective tax rate was 16.3% in 2022 compared to (2.4%) in 2021. Our current year effective tax rate was affected by enacted legislation in the Commonwealth of Pennsylvania to reduce the corporate income tax rate. The 2022 and 2021 effective tax rates were different than the statutory tax rate due to state income taxes and other discrete tax items which are detailed below. For the years ended December 31, 2022 and 2021, current income tax expense relates to state income taxes. See Note 5 to the consolidated financial statements for further discussion. The following table summarizes our tax activity for the last two years (in thousands):

	2022	2021
Total income before income taxes	$ 1,413,830	$ 402,035
U.S. federal statutory rate	21%	21%
Total tax expense at statutory rate	296,904	84,427
State and local income taxes, net of federal benefit	13,980	16,260
State rate and law change	(588)	(13,583)
Equity compensation	(673)	9,083
Change in valuation allowances:		
Federal valuation allowances	(46,633)	(84,515)
State valuation allowances	(31,693)	(23,357)
Permanent differences and other	(837)	1,942
Total expense (benefit) for income taxes	$ 230,460	$ (9,743)
Effective tax rate	16.3%	(2.4)%

We estimate our ability to utilize our deferred tax assets by analyzing projected future taxable income, the reversal patterns of our temporary differences, our loss carryforward periods and the Pennsylvania net operating loss carryforward limitations. Uncertainties such as future commodity prices can affect our calculations and can result in changes to the amount of valuation allowances.

Management's Discussion and Analysis of Financial Condition, Cash Flows, Capital Resources and Liquidity

Cash Flows

The following table presents sources and uses of cash and cash equivalents for the last two years (in thousands):

	2022	2021
Sources of cash and cash equivalents		
Operating activities	$ 1,864,744	$ 792,948
Disposal of assets	518	303
Borrowing on credit facility	972,000	1,434,000
Issuance of new senior notes	500,000	600,000
Other	72,713	53,667
Total sources of cash and cash equivalents	$ 3,409,975	$ 2,880,918
Uses of cash and cash equivalents		
Additions to natural gas and oil properties	$ (456,505)	$ (393,478)
Acreage purchases	(30,885)	(23,962)
Other property	(682)	(1,231)
Repayments on credit facility	(953,000)	(2,136,000)
Repayment of senior and subordinated notes	(1,659,422)	(63,324)
Purchases of treasury stock	(399,699)	—
Dividends paid	(38,638)	—
Other	(85,359)	(48,959)
Total uses of cash and cash equivalents	$ (3,624,190)	$ (2,666,954)

Cash flow from operating activities in 2022 was $1.9 billion compared to $792.9 million in 2021. The increase in cash provided from operating activities is the result of a 65% increase in average realized prices (including all derivative settlements and third-party transportation costs). Net cash provided from operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for 2022 was an outflow of $169.3 million compared to an outflow of $241.7 million for 2021.

Additions to natural gas and oil properties are our most significant use of cash and cash equivalents. These cash outlays are associated with our drilling and completion capital budget program. The following table shows capital expenditures and reconciles to additions to natural gas and oil properties as presented on our consolidated statements of cash flows for the last two years (in thousands):

	2022	2021
Appalachia	$ 462,134	$ 391,483
Change in capital expenditure accrual for proved properties	(5,629)	1,995
Additions to natural gas and oil properties	$ 456,505	$ 393,478

Repayment of senior and subordinated notes for 2022 includes the redemption of $850.0 million of our outstanding 9.25% senior notes due 2026, $169.6 million of our 5.00% senior notes due 2022, $48.5 million of our 5.87% senior notes due 2022 and $532.3 million of our 5.00% senior notes due 2023.

Liquidity and Capital Resources

Our main sources of liquidity are cash, internally generated cash flow from operations, capital market transactions and our bank credit facility. At December 31, 2022, we had approximately $1.2 billion of liquidity consisting of cash and availability under our bank credit facility. Based on the current commodity price environment, we believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion commitments in order to maintain flexibility with regard to our activity level and capital expenditures.

Sources of Cash

During the year ended December 31, 2022, we generated $1.9 billion of cash flows from operating activities. As of December 31, 2022, the remaining available borrowing capacity under our bank credit facility was $1.2 billion and we had $207,000 cash on hand. Our borrowing base can be adjusted as a result of changes in commodity prices, acquisitions or divestitures of proved properties or financing activities. We may draw on our bank credit facility to meet short-term cash requirements.

Our working capital requirements are supported by our cash and our bank credit facility. We believe our short-term and long-term liquidity is adequate to fund our current operations and our long-term funding requirements including our capital spending programs, repayment of debt maturities and dividends. Although we expect cash flows and capacity under the existing credit facility to be sufficient to fund our expected 2023 capital program, we may also elect to raise funds through new debt or equity offerings or from other sources of financing. Any downgrades in our credit ratings could make it more difficult or expensive for us to borrow additional funds. All of our sources of liquidity can be affected by the general conditions of the broader economy, the global pandemic, force majeure events and fluctuations in commodity prices, operating costs and volumes produced, all of which affect us and our industry. We have no control over market prices for natural gas, NGLs or oil, although we may be able to influence the amount of realized revenues through the use of derivative contracts as part of our commodity price risk management.

Bank Credit Facility

In April 2022, we entered into an amended bank credit facility which is secured by substantially all of our assets and has a maturity date of April 14, 2027. As of December 31, 2022, we had outstanding borrowings under our bank credit facility of $19.0 million and we maintain a borrowing base of $3.0 billion and aggregate lender commitments of $1.5 billion. We also have undrawn letters of credit of $307.4 million as of December 31, 2022.

The borrowing base is subject to regular, semi-annual redeterminations and is dependent on a number of factors but primarily the lender's assessment of future cash flows. The next scheduled borrowing base redetermination is during the spring of 2023. We currently must comply with certain financial and non-financial covenants, including limiting dividend payments, debt incurrence and requirements that we maintain certain financial ratios (as defined in our bank credit agreement). We were in compliance with all such covenants at December 31, 2022.

Our daily weighted-average bank credit facility debt balance was $48.4 million for the year ended December 31, 2022 compared to $144.9 million for the year ended December 31, 2021. Borrowings under the bank credit facility can either be at the alternate base rate ("ABR," as defined in the bank credit facility agreement) plus a spread ranging from 0.75% to 1.75% or at the secured overnight financing rate (SOFR, as defined in the bank credit facility agreement) plus a spread ranging from 1.75% to 2.75%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our SOFR loans to base rate loans or to convert all or any of the base rate loans to SOFR loans.

Uses of Cash

We use cash for the development, exploration and acquisition of natural gas and oil properties and for the payment of gathering, transportation and processing costs, operating, general and administrative costs, taxes and debt obligations, including interest, dividends and share repurchases. Expenditures for the development, exploration and acquisition of natural gas and oil properties are the primary use of our capital resources. During 2022, we funded $488.1 million in capital expenditures as reported in our consolidated statement of cash flows. We currently expect our capital budget for 2023 to be in the range of $570 to $615 million. The amount of our future capital expenditures will depend upon a number of factors including our cash flows from operating, investing and financing activities, infrastructure availability, supply and demand fundamentals and our ability to execute our development program. In addition, the impact of commodity prices on investment opportunities, the availability of capital and the timing and results of our development activities may lead to changes in funding requirements for future development. We periodically review our budget to assess changes in current and projected cash flows, debt requirements and other factors.

We may from time to time repurchase or redeem all or portions of our outstanding debt securities for cash, through exchanges for other securities or a combination of both. Such repurchases or redemptions may be made in open market transactions and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. Our next significant long-term debt maturity is in the amount of $750.0 million due 2025. As part of our strategy for 2023, we will continue to focus on improving our debt metrics.

The share repurchase program authorized by our board of directors includes approval to repurchase $1.5 billion of our common stock. During 2022, we repurchased 14.0 million shares and $1.1 billion remains authorized under this program as of December 31, 2022.

In third quarter 2022, our board of directors re-instituted our quarterly dividend. During 2022, we paid dividends totaling $38.6 million.

Shelf Registration

We have a universal shelf registration statement filed with the SEC under which we, as a "well-known seasoned issuer" for purposes of SEC rules, have the ability to sell an indeterminate amount of various types of debt and equity securities.

Capitalization and Dividend Payments

As of December 31, 2022 and 2021, our total debt and capitalization were as follows (in thousands):

	2022	2021
Bank debt	$ 9,509	$ —
Senior notes	1,832,451	2,925,787
Total debt	1,841,960	2,925,787
Stockholders' equity	2,876,006	2,085,663
Total capitalization	$ 4,717,966	$ 5,011,450
Debt to capitalization ratio	39.0%	58.4%

In 2022, we paid a total of $38.6 million in dividends to our stockholders ($0.08 cents per common share for both the third and fourth quarters). The amount of future dividends is subject to declaration by the board of directors and primarily depends on earnings, capital expenditures and various other factors.

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, derivative obligations, asset retirement obligations, and transportation, gathering and processing commitments. As of December 31, 2022, we do not have any capital leases or any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of December 31, 2022, we had a total of $307.4 million of letters of credit outstanding under our bank credit facility. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2022. In addition to the contractual obligations listed in the table below, our consolidated balance sheet at December 31, 2022 reflects accrued interest payable on our bank debt of $1.1 million, which is payable in first quarter 2023. We expect to make annual interest payments through the end of each note maturity, based upon the amounts outstanding at December 31, 2022, of $23.8 million on our 4.75% senior notes, $36.6 million on our 4.875% senior notes and $49.5 million on our 8.25% senior notes.

The following summarizes our contractual financial obligations at December 31, 2022 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, and, if necessary, borrowings under our bank credit facility or other sources (in thousands).

	Payment due by period					
	2023	2024	2025	2026 and 2027	Thereafter	Total
Debt:						
Bank debt due 2027 [a]	$ —	$ —	$ —	$ 19,000	$ —	$ 19,000
4.875% senior notes due 2025	—	—	750,000	—	—	750,000
8.25% senior notes due 2029	—	—	—	—	600,000	600,000
4.75% senior notes due 2030	—	—	—	—	500,000	500,000
Other obligations:						—
Operating leases, net	70,873	8,119	6,576	8,793	—	94,361
Software licenses and other	2,419	555	295	48	15	3,332
Derivative obligations [b]	151,417	15,495	—	—	—	166,912
Transportation and gathering commitments[c]	801,850	782,445	694,670	1,218,509	2,971,614	6,469,088
Asset retirement obligation liability [d]	4,570	38	—	—	105,243	109,851
Total contractual obligations [e]	$ 1,031,129	$ 806,652	$ 1,451,541	$ 1,246,350	$ 4,176,872	$ 8,712,544

(a) Due at termination date of our bank credit facility. Interest paid on our bank credit facility would be approximately $1.6 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations represent net liabilities determined in accordance with master netting arrangements for commodity derivatives that were valued as of December 31, 2022. Our derivatives are measured and recorded at fair value and are subject to market and credit risk. The ultimate liquidation value will be dependent upon actual future commodity prices which may differ materially from the inputs used to determine fair value as of December 31, 2022. See Note 9 to our consolidated financial statements.

(c) The obligations above represent our minimum financial commitments pursuant to the terms of these contracts. Our actual expenditures may exceed these minimum commitments.

(d) The amount above represents the discounted values. There are inherent uncertainties surrounding the obligations and the actual amount and timing may differ from our estimates. See Note 8 to our consolidated financial statements.

(e) This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets and does not include obligations to taxing authorities.

In addition to the amounts included in the above table, we have entered into an additional agreement which is contingent on certain pipeline modifications and/or construction for natural gas volumes of 1.8 Bcf per day and is expected to begin in 2024 with a thirteen-year term. Volumes under this agreement decline in the last five years of the contract, ending at 810,000 mcf per day.

Not included in the table above is our estimate of accrued contractual obligations related to certain obligations retained by us after our divestiture of our North Louisiana assets. These contractual obligations are related to gathering, processing and transportation agreements including certain minimum volume commitments. There are inherent uncertainties surrounding the retained obligation and, as a result, the determination of the accrued obligation required significant judgement and estimation. The actual settlement amount and timing may differ from our estimates. See also Note 3, Note 14 and Note 15 to our consolidated financial statements. As of December 31, 2022, the carrying value of this obligation was $390.6 million (discounted) and is included in divestiture contract obligation in our consolidated balance sheets. As of December 31, 2022, our estimated settlement of this retained obligation based on a discounted value is as follows (in thousands):

	Year Ended December 31,
2023	$ 86,546
2024	73,916
2025	64,276
2026	45,773
2027	37,743
Thereafter	82,366
	$ 390,620

Proved Reserves

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	Year End December 31,	
	2022	2021
	(Mmcfe)	
Proved Reserves:		
Beginning of year	17,775,484	17,203,114
Reserve additions	1,668,244	1,602,769
Reserve revisions	(591,983)	(252,876)
Sales	—	—
Production	(774,089)	(777,523)
End of year	18,077,656	17,775,484
Proved Developed Reserves:		
Beginning of year	10,417,887	9,792,540
End of year	10,933,180	10,417,887

Our proved reserves at year-end 2022 were 18.1 Tcfe compared to 17.8 Tcfe at year-end 2021. Natural gas comprised approximately 65% of our proved reserves at year-end 2022.

Reserve Additions and Revisions. During 2022, we added 1.7 Tcfe of proved reserves from drilling activities and evaluation of proved areas in Pennsylvania. Approximately 77% of the 2022 reserve additions are attributable to natural gas. Our ethane reserves are intended to match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of a negative 592.0 Bcfe includes 1.4 Tcfe reserves reclassified to unproved because of previously planned wells not expected to be drilled within the original five year development horizon significantly offset by favorable pricing revisions, positive performance revisions of 72.8 Bcfe and 716.2 Bcfe positive revisions for previously proved undeveloped properties as they were added back to our five-year development plan. Wells reclassified to unproved during the year are the result of the outperformance of existing wells which resulted in a higher utilization of in-field gathering capacity and a reallocation of capital due to the drilling of longer laterals on existing locations. During 2021, we added 1.6 Tcfe of proved reserves from drilling activities and evaluation of proved areas in Pennsylvania. Approximately 72% of the 2021 reserve additions are attributable to natural gas. Our ethane reserves are intended to match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of a negative 252.9 Bcfe includes 1.3 Tcfe reserves reclassified to unproved because of previously planned wells not expected to be drilled within the original five year development horizon significantly offset by favorable pricing revisions of 22.6 Bcfe and positive performance revisions of 1.0 Tcfe.

Future Net Cash Flows. At December 31, 2022, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $29.6 billion. The present value of our estimated future net cash flows at December 31, 2021 was $14.9 billion. This present value was calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves, in accordance with SEC rules. At December 31, 2022, the after-tax present value of estimated future net cash flows from our proved reserves was $24.5 billion compared to $12.5 billion at December 31, 2021.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money to the evaluating party and the perceived risks inherent in producing oil and gas.

Delivery Commitments

We have various volume delivery commitments that are related to our Marcellus Shale properties. We expect to be able to fulfill our contractual obligations from our own production; however, we may purchase third-party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2022, our delivery commitments through 2037 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2023	365,000	50,000
2024	261,899	50,000
2025	182,493	50,000
2026	158,301	50,000
2027	100,000	46,233
2028	100,000	45,000
2029	100,000	33,444
2030	—	30,000
2031	—	16,575
2032-2037	—	10,000 (each year)

In addition to the amounts included in the above table, we have contracted with a pipeline company through 2037 to deliver ethane production volumes from our Marcellus Shale wells. These agreements and related fees, which are contingent upon facility construction and/or modification, are for 15,000 bbls per day starting in 2027 through 2033.

Other

We lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages, or other events could result in significant future costs.

Interest Rates

At December 31, 2022, we had $1.9 billion of debt outstanding which bears interest at fixed rates averaging 5.9% and bank debt totaling $19.0 million bearing interest at floating rates, which averaged 8.25% at year-end 2022. The one month SOFR rate on December 31, 2022 was 4.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2022 would cost us approximately $190,000 in additional annual interest.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resources position. However, as is customary in the natural gas and oil industry, we have various contractual work commitments which are described above under cash contractual obligations.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Estimated Quantities of Net Reserves

We use the successful efforts method of accounting for natural gas and oil producing activities as opposed to the alternate acceptable full cost method. We believe that net assets and net income are more conservatively measured under the successful efforts method of accounting than under the full cost method, particularly during periods of active exploration. One difference between the successful efforts method of accounting and the full cost method is that under the successful efforts method, all exploratory dry holes and geological and geophysical costs are charged against earnings during the periods they occur; whereas, under the full cost method of accounting, such costs are capitalized as assets, pooled with the costs of successful wells and charged against earnings of future periods as a component of depletion expense. Under the successful efforts method of accounting, successful exploration drilling costs and all development costs are capitalized and these costs are systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves for which a development plan has been adopted indicating each location is scheduled to be drilled within five years from the date it was booked as proved reserves, unless specific circumstances justify a longer time. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start up or shut in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our President and Chief Executive Officer. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to audit our estimates of proved reserves. Estimates prepared by third parties may be higher or lower than those included herein. Independent petroleum consultants audited approximately 96% of our reserves in 2022 and 97% of our reserves in 2021. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. The reserves included in this report are those reserves estimated by our petroleum engineering staff. For additional discussion, see Items 1 & 2. Business and Properties – *Proved Reserves*.

Reserves are based on the weighted average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC. When determining the December 31, 2022 proved reserves for each property, benchmark prices are adjusted using price differentials that account for property-specific quality and location differences. If prices in the future average below prices used to determine reserves at December 31, 2022, it could have an adverse effect on our estimates of proved reserves. It is difficult to estimate the magnitude of any potential price change and the effect on proved reserves due to numerous factors (including commodity prices and performance revisions).

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property’s total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Based on proved reserves at December 31, 2022, we estimate that a 1% change in proved reserves would increase or decrease 2023 depletion expense by approximately $3.0 million (based on current production estimates). Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 17 to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis. It should not be assumed that the standardized measure is the current market value of our estimated proved reserves.

Fair Value Estimates

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value, or range of present values, using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy, while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1-Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2-Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3-Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management’s best estimates of the assumptions market participants would use in determining fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Note 10 to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurement include:

- impairment assessments of long-lived assets; and
- recorded value of certain derivative instruments.

The need to test long-lived assets for impairment can be based on several indicators, including a significant reduction in commodity prices, reductions to our capital budget, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which a property is located.

Exit Cost Estimates

Our consolidated balance sheets include accrued exit cost liabilities primarily related to retained gathering, processing and transportation contracts in Louisiana. Inherent in the initial fair value calculation of these exit costs associated with our North Louisiana divestiture are numerous assumptions and judgments including the ultimate amounts to be paid, the credit-adjusted discount rates, the development plans of the buyer and our probability weighted forecast of those drilling plans, market conditions and the ultimate usage by the buyer of each facility included in the agreement. A significant portion of this obligation is a gas processing agreement that includes a deficiency payment if the minimum volume commitment is not met and we must assess the likelihood and amount of production volumes flowing to this facility. In addition, our agreement includes additional transportation agreements that are based on contractual rates applied to a minimum volume usage. We have made significant judgments and estimates regarding the timing and amount of these liabilities. We based our initial fair value estimate on assumptions we believe to be reasonable and likely to occur. If the drilling development does not occur as we have assumed, the carrying value of the liability could increase by approximately $20.0 million. Changes in other assumptions, such as the estimate of production volumes flowing to processing facilities, could result in a higher liability. If we assume the flow of production volumes was held flat through the end of the contract, the liability could increase by approximately $20.0 million. We continue to regularly monitor our estimates and in the future may be required to adjust our estimates based on facts and circumstances. See Note 14 and Note 15 to our consolidated financial statements for a further discussion of these costs.

Impairment Assessments of Natural Gas and Oil Properties

Long-lived assets in use are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of an impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value. As of December 31, 2022, our estimated undiscounted cash flows relating to our long-lived assets significantly exceeded their carrying values. See Note 10 to the consolidated financial statements for discussion of impairments recorded in the last three years and the related fair value measurements.

Fair value calculated for the purpose of testing our natural gas and oil properties for impairment is estimated using the present value of expected future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- *Future crude oil and condensate, NGLs and natural gas prices.* Our estimates of future prices are based on market information including published futures prices. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by market supply and demand. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in crude oil and condensate, NGLs and natural gas prices and estimates of such future prices are inherently imprecise. See Item 1A. Risk Factors for further discussion on commodity prices.
- *Estimated quantities of crude oil and condensate, NGLs and natural gas.* Such quantities are based on risk adjusted proved and probable reserves and resources such that the combined volumes represent the most likely expectation of recovery. See Item 1A. Risk Factors for further discussion on reserves.
- *Expected timing of production.* Production forecasts are the outcome of engineering studies which estimate reserves, as well as expected capital programs. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.
- *Discount rate commensurate with the risks involved.* We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. A higher discount rate decreases the net present value of cash flows.
- *Future capital requirements.* Our estimates of future capital requirements consider the assumptions utilized by management for internal planning and budgeting.

We base our fair value estimates on projected financial information which we believe to be reasonably likely to occur. An estimate of the sensitivity to changes in assumptions in our undiscounted cash flow calculations is not practicable, given the numerous assumptions (e.g. reserves, pace and timing of development plans, commodity prices, capital expenditures, operating costs, drilling and development costs, inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future undiscounted cash flows would likely be partially offset by lower costs.

Commodity Derivative Instruments

All commodity derivative instruments are recorded on our consolidated balance sheets as either an asset or a liability measured at its fair value. Fair value measurements for certain of our commodity derivatives are based upon, among other things, option pricing models, futures, volatility, time to maturity and credit risk and are discussed in Note 10 to our consolidated financial statements. We regularly validate our fair value measurements through the review of counterparty statements, by corroborating original sources of inputs and monitoring changes in valuation methods and assumptions. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Income Taxes

We are subject to income and other taxes in all areas in which we operate. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws. Our effective tax rate is subject to variability as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which could affect us. Our effective rate is also affected by changes in the allocation of revenue among states.

Our consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax returns before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the potential realization of deferred tax assets, management must consider whether it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine that an additional deferred tax asset valuation allowance should be established. In determining whether a valuation allowance is required for our deferred tax asset balances, we consider, among other factors, current financial position, results of operations, projected future taxable income, tax planning strategies and new legislation. Significant judgment is involved in this determination as we are required to make assumptions about future commodity prices, projected production, development activities, profitability of future business strategies and forecasted economics in the oil and gas industry. Additionally, changes in the effective tax rate resulting from changes in tax law and our level of earnings may limit utilization of deferred tax assets and will affect valuation of deferred tax balances in the future. Changes in judgment regarding future realization of deferred tax assets may result in a reversal of all or a portion of the valuation allowance. For example, based upon a significant increase in commodity prices and other positive evidence, we released a significant portion of our federal and state valuation allowance during 2022. In the period that determination is made, our net income will benefit from a lower effective tax rate.

We believe our net deferred tax assets, after valuation allowances, will ultimately be realized. During 2022, we decreased our valuation allowances against our state net operating loss carryforwards, basis differences and credits from $203.1 million as of December 31, 2021 to $171.4 million as of December 31, 2022. The federal valuation allowances decreased from $68.0 million as of December 31, 2021 to $21.3 million as of December 31, 2022. See Note 5 to our consolidated financial statements for further information concerning our income taxes.

An estimate of the sensitivity to changes in our assumptions resulting in future income calculations is not practical, given the numerous assumptions that can materially affect our estimates. Unfavorable adjustments to some of the assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future taxable income would likely be partially offset by lower capital expenditures.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, income or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Accounting Standards Not Yet Adopted

None that are expected to have a material impact.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Market Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices as the volatility of these prices continues to impact our industry. We expect commodity prices to remain volatile and unpredictable in the future. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. These derivative instruments apply to a varying portion of our production and provide only partial price protection. These arrangements limit the benefit to us of increases in prices but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the derivatives. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price changes related to the underlying commodity transaction. While the use of derivative instruments could materially affect our results of operations in a particular quarter or annual period, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American natural gas production. Natural gas prices affect us more than oil prices because approximately 65% of our December 31, 2022 proved reserves were natural gas compared to 2% of proved reserves were oil. In addition, a portion of our NGLs, which are 33% of proved reserves, are also impacted by changes in oil prices. At times, we are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2021 to December 31, 2022.

We believe NGLs prices are somewhat seasonal, particularly for propane. Therefore, the relationship of NGLs prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand. We sell NGLs in several regional and international markets. If we are not able to sell or store NGLs, we may be required to curtail production or shift our drilling activities to dry gas areas.

The Appalachian region has limited local demand and infrastructure to accommodate ethane. We have agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area. We cannot ensure that these facilities will remain available. If we are not able to sell ethane under at least one of our agreements, we may be required to curtail production or, as we have done in the past, purchase or divert natural gas to blend with our rich residue gas.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program may also include collars, which establish a minimum floor price and a predetermined ceiling price. Our program may also include a three-way collar which is a combination of three options: a sold call, a purchased put and a sold put. The sold call establishes the ceiling price while the purchased put establishes the floor price until the market price for the commodity falls below the sold put stock price at which price the value of the purchased put is effectively capped. At December 31, 2022, our derivatives program includes swaps, collars and three-way-collars. These contracts expire monthly through December 2024. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2022, approximated a net derivative liability of $138.6 million compared to a net derivative liability of $169.5 million at December 31, 2021. This change is primarily related to the settlements of derivative contracts during 2022 and to the natural gas, NGLs and oil futures prices as of December 31, 2022 in relation to the new commodity derivative contracts we entered into during 2022 for 2023 and 2024. At December 31, 2022, the following commodity derivative contracts were outstanding, excluding our basis swaps and divestiture contingent consideration, which is separately discussed below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price				Fair Market Value (in thousands)
			Swap	Sold Put	Floor	Ceiling	
Natural Gas							
2023	Swaps	376,384 Mmbtu/day	$ 3.44				$ (109,138)
2023	Collars	278,082 Mmbtu/day			$ 3.60	$ 4.78	$ (12,714)
2023	Three-way Collars	187,233 Mmbtu/day		$ 2.67	$ 3.74	$ 4.83	$ (11,917)
2024	Swaps	110,000 Mmbtu/day	$ 4.63				$ 13,202
2024	Collars	469,235 Mmbtu/day			$ 3.55	$ 5.51	$ (5,930)
Crude Oil							
2023	Swaps	5,123 bbls/day	$ 71.39				$ (13,908)
January-September 2024	Collars	832 bbls/day			$ 80.00	$ 90.12	$ 1,807

Other Commodity Risk

We are impacted by basis risk as natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the derivative contracts above, we have entered into natural gas basis swap agreements. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively lock in the basis adjustments. The fair value of the natural gas basis swaps, which expire monthly through December 2026, was a net derivative asset of $521,000 at December 31, 2022 and the volumes are for 288,555,000 Mmbtu.

We have the right to receive contingent consideration in conjunction with the sale our North Louisiana assets of up to $21.0 million based on future realization of natural gas and oil prices based on published indexes and realized NGLs prices of the buyer for 2023. The fair value of this instrument on December 31, 2022 was a derivative asset of $13.1 million. In addition, we expect to receive $24.5 million for the year ended December 31, 2022 which is reported as a current asset on our consolidated balance sheet.

Commodity Sensitivity Analysis

The following table shows the fair value of our derivative contracts and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at December 31, 2022. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Change In Fair Value			
		Increase in Commodity Price of		Decrease in Commodity Price of	
	Fair Value	10%	25%	10%	25%
Swaps	$ (109,844)	$ (86,562)	$ (216,404)	$ 86,562	$ 216,405
Collars	(16,837)	(81,262)	(208,659)	79,294	193,932
Three-way collars	(11,917)	(20,137)	(53,621)	17,892	38,870
Basis swaps	521	13,179	32,947	(13,179)	(32,947)
Divestiture contingent consideration	13,080	1,330	2,740	(1,760)	(5,190)

Counterparty Risk

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and commodity traders and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2022, our derivative counterparties include fourteen financial institutions, of which all but six are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions and large commodity traders, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by certain of our counterparties, which was immaterial.

Interest Rate Risk

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate publicly traded debt and at times, variable rate bank debt. At December 31, 2022, we had $1.9 billion of debt outstanding which bears interest at a fixed rate averaging 5.9%. As of December 31, 2022, we had $19.0 million of variable rate bank debt outstanding compared to no variable rate bank debt outstanding at December 31, 2021. Our bank credit facility bears interest at floating rates, which was 8.25% at December 31, 2022. On December 31, 2022, the one month SOFR rate was 4.4%. A 1% increase in short-term rates on floating-rate debt outstanding at December 31, 2022 would cost us approximately $190,000 in additional annual interest. Our sensitivity to interest rate movements and corresponding changes in the fair value of our fixed rate debt affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices different than carrying value. See Note 7 to our consolidated financial statements for more information about our senior notes.

The fair value of our senior debt is based on December 31, 2022 quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Notes due 2025	$ 750,000	$ 714,870
(The interest rate is fixed at a rate of 4.875%)		
Senior Notes due 2029	600,000	618,312
(The interest rate is fixed at a rate of 8.25%)		
Senior Notes due 2030	500,000	442,350
(The interest rate is fixed at a rate of 4.75%)		
	$ 1,850,000	$ 1,775,532

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders of Range Resources Corporation:

Management is responsible for establishing and maintaining an adequate system of internal control over financial reporting (as defined in Rule 13(a)-15(f) under the Securities Exchange Act of 1934, as amended). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and presentation of consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that the internal controls may become inadequate because of changes in conditions or because the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2022. In making this assessment, which was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013).* Based on our assessment, we believe that, as of December 31, 2022, our internal control over financial reporting was effective based on those criteria.

Ernst and Young LLP, our independent registered public accounting firm, audited our financial statements included in this annual report and has issued an attestation report on our internal control over financial reporting as of December 31, 2022. Their report appears on the following page.

By: /s/ JEFFREY L. VENTURA
Jeffrey L. Ventura
Chief Executive Officer and President

By: /s/ MARK S. SCUCCHI
Mark S. Scucchi
Executive Vice President and Chief Financial Officer

Fort Worth, Texas
February 27, 2023

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on Internal Control Over Financial Reporting

We have audited Range Resources Corporation's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Range Resources Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2022 and 2021, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and our report dated February 27, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's 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 generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 27, 2023

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2022 and 2021, the related consolidated statements of operations, comprehensive income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 2022, and 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 at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 27, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Depletion, depreciation, and amortization of proved natural gas and oil properties

Description of the Matter	At December 31, 2022, the net book value of the Company's proved natural gas and oil properties totaled $5.1 billion and depletion, depreciation and amortization expense ("DD&A") was $353.4 million for the year then ended. As described in Note 2 to the consolidated financial statements, the Company follows the successful efforts method of accounting for its natural as and oil producing activities. Under this method, DD&A for proved properties, including other property and equipment such as gathering lines related to natural gas and oil producing activities, is provided using the units of production method based on proved natural gas and oil reserves, as estimated by the Company's petroleum engineering staff. Proved oil and gas reserves are prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Judgment is required by the Company's petroleum engineering staff in interpreting the data used to estimate reserves. Estimating proved natural gas and oil reserves requires the selection and evaluation of inputs, including historical production, natural gas and oil price assumptions, and future operating and capital cost assumptions, among others. Because of the complexity involved in estimating natural gas and oil reserves, management used independent petroleum consultants to audit the proved reserve estimates prepared by the Company's petroleum engineering staff as of December 31, 2022.

Auditing the Company’s DD&A calculation is especially complex because of the use of the work of the petroleum engineering staff and the independent petroleum consultants and the evaluation of management’s determination of the inputs described above used by the engineers in estimating proved natural gas and oil reserves.

We obtained an understanding, evaluated the design and tested the operating effectiveness of the internal controls that address the risks of material misstatement relating to the DD&A calculation, including controls over the completeness and accuracy of the financial data used in estimating proved natural gas and oil reserves.

How We Addressed the Matter in Our Audit	Our testing of the Company's DD&A calculation included, among other procedures evaluating the professional qualifications and objectivity of the individual primarily responsible for overseeing the preparation of the reserve estimates by the petroleum engineering staff and the independent petroleum consultants used to audit the estimates. On a sample basis, we tested the completeness and accuracy of the financial data used in the estimation of proved natural gas and oil reserves by agreeing significant inputs to source documentation, where applicable, and assessing the inputs for reasonableness based on our review of corroborative evidence and consideration of any contrary evidence. Additionally, we performed analytic procedures on select inputs into the natural gas and oil reserve estimate as well as lookback procedures on the output. Finally, we tested that the DD&A calculation is based on the appropriate proved natural gas and oil reserve amounts from the Company's reserve report.

/s/ Ernst & Young LLP

We have served as the Company’s auditor since 2003.

Fort Worth, Texas
February 27, 2023

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2022	December 31, 2021
Assets		
Current assets:		
Cash and cash equivalents	$ 207	$ 214,422
Accounts receivable, less allowance for doubtful accounts of $314 and $568	481,050	471,775
Contingent consideration receivable	24,500	29,500
Derivative assets	925	5,738
Prepaid and other current assets	32,905	15,230
Total current assets	539,587	736,665
Derivative assets	40,990	38,601
Natural gas and oil properties, successful efforts method	10,655,879	10,175,570
Accumulated depletion and depreciation	(4,765,475)	(4,420,914)
	5,890,404	5,754,656
Other property and equipment	74,638	74,678
Accumulated depreciation and amortization	(72,204)	(71,184)
	2,434	3,494
Operating lease right-of-use assets	84,070	40,832
Other assets	68,077	86,259
Total assets	$ 6,625,562	$ 6,660,507
Liabilities		
Current liabilities:		
Accounts payable	$ 206,738	$ 178,413
Asset retirement obligations	4,570	5,310
Accrued liabilities	442,922	392,605
Deferred compensation liabilities	89,334	28,293
Accrued interest	39,138	75,940
Derivative liabilities	151,417	162,767
Divestiture contract obligation	86,546	91,120
Current maturities of long-term debt	—	218,017
Total current liabilities	1,020,665	1,152,465
Bank debt	9,509	—
Senior notes	1,832,451	2,707,770
Deferred tax liabilities	333,571	117,642
Derivative liabilities	15,495	8,216
Deferred compensation liabilities	99,907	137,102
Operating lease liabilities	20,903	24,861
Asset retirement obligations and other liabilities	112,981	101,509
Divestiture contract obligation	304,074	325,279
Total liabilities	3,749,556	4,574,844
Commitments and contingencies		
Stockholders' Equity		
Preferred stock, $1 par 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par 475,000,000 shares authorized, 262,887,265 issued at December 31, 2022 and 259,795,554 issued at December 31, 2021	2,629	2,598
Common stock held in treasury, at cost, 24,001,535 shares at December 31, 2022 and 10,002,646 shares at December 31, 2021	(429,659)	(30,007)
Additional paid-in capital	5,764,970	5,720,277
Accumulated other comprehensive gain (loss)	467	(150)
Retained deficit	(2,462,401)	(3,607,055)
Total stockholders' equity	2,876,006	2,085,663
Total liabilities and stockholders' equity	$ 6,625,562	$ 6,660,507

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2022	**2021**	**2020**
Revenues and other income:			
Natural gas, NGLs and oil sales	$ 4,911,092	$ 3,215,027	$ 1,607,713
Derivative fair value (loss) income	(1,188,506)	(650,216)	187,711
Brokered natural gas, marketing and other	424,217	365,412	173,273
Total revenues and other income	4,146,803	2,930,223	1,968,697
Costs and expenses:			
Direct operating	84,286	75,287	92,157
Transportation, gathering, processing and compression	1,242,941	1,174,469	1,088,490
Taxes other than income	35,367	30,648	25,649
Brokered natural gas and marketing	427,048	367,288	188,316
Exploration	26,772	23,555	32,654
Abandonment and impairment of unproved properties	28,608	7,206	19,334
General and administrative	168,085	168,435	158,383
Exit costs	70,337	21,661	547,409
Deferred compensation plan	61,880	68,351	12,541
Interest	165,145	227,336	192,667
Loss (gain) on early extinguishment of debt	69,493	98	(14,068)
Depletion, depreciation and amortization	353,420	364,555	394,330
Impairment of proved properties and other assets	—	—	78,955
Gain on the sale of assets	(409)	(701)	(110,791)
Total costs and expenses	2,732,973	2,528,188	2,706,026
Income (loss) before income taxes	1,413,830	402,035	(737,329)
Income tax expense (benefit):			
Current	14,688	7,984	(523)
Deferred	215,772	(17,727)	(25,029)
	230,460	(9,743)	(25,552)
Net income (loss)	$ 1,183,370	$ 411,778	$ (711,777)
Net income (loss) per common share:			
Basic	$ 4.79	$ 1.65	$ (2.95)
Diluted	$ 4.69	$ 1.61	$ (2.95)
Weighted average common shares outstanding:			
Basic	240,858	242,862	241,373
Diluted	246,379	249,314	241,373

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Year Ended December 31,		
	2022	**2021**	**2020**
Net income (loss)	$ 1,183,370	$ 411,778	$ (711,777)
Other comprehensive loss:			
Postretirement benefits:			
Actuarial gain	482	62	39
Amortization of prior service costs	292	369	369
Income tax expense	(157)	(102)	(99)
Total comprehensive income (loss)	$ 1,183,987	$ 412,107	$ (711,468)

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2022	**2021**	**2020**
Operating activities:			
Net income (loss)	$ 1,183,370	$ 411,778	$ (711,777)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:			
Deferred income tax expense (benefit)	215,772	(17,727)	(25,029)
Depletion, depreciation and amortization and impairment of proved properties	353,420	364,555	473,285
Abandonment and impairment of unproved properties	28,608	7,206	19,334
Derivative fair value loss (income)	1,188,506	650,216	(187,711)
Cash settlements on derivative financial instruments	(1,190,154)	(520,013)	322,629
Divestiture contract obligation	69,766	20,340	499,934
Allowance for bad debt	(250)	200	400
Amortization of deferred financing costs and other	7,959	8,347	7,807
Deferred and stock-based compensation	107,959	110,356	48,552
Gain on the sale of assets	(409)	(701)	(110,791)
Loss (gain) on early extinguishment of debt	69,493	98	(14,068)
Changes in working capital:			
Accounts receivable	(3,286)	(250,538)	24,539
Prepaid and other	(18,438)	(1,140)	1,010
Accounts payable	17,077	39,231	(32,686)
Accrued liabilities and other	(164,649)	(29,260)	(46,748)
Net cash provided from operating activities	1,864,744	792,948	268,680
Investing activities:			
Additions to natural gas and oil properties	(456,505)	(393,478)	(405,617)
Additions to field service assets	(682)	(1,231)	(2,873)
Acreage purchases	(30,885)	(23,962)	(26,816)
Proceeds from disposal of assets	518	303	246,127
Purchases of marketable securities held by the deferred compensation plan	(43,691)	(30,806)	(17,076)
Proceeds from the sales of marketable securities held by the deferred compensation plan	41,413	31,295	22,173
Net cash used in investing activities	(489,832)	(417,879)	(184,082)
Financing activities:			
Borrowings on credit facilities	972,000	1,434,000	2,076,000
Repayments on credit facilities	(953,000)	(2,136,000)	(1,851,000)
Issuance of senior notes	500,000	600,000	850,000
Repayment of senior or senior subordinated notes	(1,659,422)	(63,324)	(1,120,634)
Dividends paid	(38,638)	—	—
Treasury stock purchases	(399,699)	—	(22,992)
Debt issuance costs	(16,176)	(8,854)	(13,608)
Taxes paid for shares withheld	(25,492)	(9,299)	(3,324)
Change in cash overdrafts	9,071	16,493	176
Proceeds from the sales of common stock held by the deferred compensation plan	22,229	5,879	696
Net cash used in financing activities	(1,589,127)	(161,105)	(84,686)
(Decrease) increase in cash and cash equivalents	(214,215)	213,964	(88)
Cash and cash equivalents at beginning of year	214,422	458	546
Cash and cash equivalents at end of year	$ 207	$ 214,422	$ 458

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

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except per share data)

	Common stock		Treasury	Common stock held in	Additional paid-in	Retained	Accumulated other comprehensive	
	Shares	**Par value**	**shares**	**treasury**	**capital**	**deficit**	**income (loss)**	**Total**
Balance as of December 31, 2019	251,439	$ 2,514	1,808	$ (7,236)	$ 5,659,832	$ (3,306,834)	$ (788)	**$ 2,347,488**
Issuance of common stock	4,896	49	—	—	(942)	—	—	**(893)**
Issuance of common stock upon vesting of PSUs	19	—	—	—	74	(74)	—	—
Stock-based compensation expense	—	—	—	—	25,400	—	—	**25,400**
Treasury stock issuance	—	—	(2)	96	(96)	—	—	—
Treasury stock repurchased	—	—	8,200	(22,992)	—	—	—	**(22,992)**
Other comprehensive income	—	—	—	—	—	—	309	**309**
Net loss	—	—	—	—	—	(711,777)	—	**(711,777)**
Balance as of December 31, 2020	256,354	2,563	10,006	(30,132)	5,684,268	(4,018,685)	(479)	**1,637,535**
Issuance of common stock	3,429	35	—	—	6,998	—	—	**7,033**
Issuance of common stock upon vesting of PSUs	13	—	—	—	148	(148)	—	—
Stock-based compensation expense	—	—	—	—	28,988	—	—	**28,988**
Treasury stock issuance	—	—	(3)	125	(125)	—	—	—
Other comprehensive income	—	—	—	—	—	—	329	**329**
Net income	—	—	—	—	—	411,778	—	**411,778**
Balance as of December 31, 2021	259,796	2,598	10,003	(30,007)	5,720,277	(3,607,055)	(150)	**2,085,663**
Issuance of common stock	3,089	31	—	—	13,529	—	—	**13,560**
Issuance of common stock upon vesting of PSUs	2	—	—	—	78	(78)	—	—
Stock-based compensation expense	—	—	—	—	31,133	—	—	**31,133**
Cash dividends paid ($0.16 per share)	—	—	—	—	—	(38,638)	—	**(38,638)**
Treasury stock issuance	—	—	(1)	47	(47)	—	—	—
Treasury stock repurchased	—	—	14,000	(399,699)	—	—	—	**(399,699)**
Other comprehensive income	—	—	—	—	—	—	617	**617**
Net income	—	—	—	—	—	1,183,370	—	**1,183,370**
Balance as of December 31, 2022	**262,887**	**$ 2,629**	**24,002**	**$ (429,659)**	**$ 5,764,970**	**$ (2,462,401)**	**$ 467**	**$ 2,876,006**

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

(1) Summary of Organization and Nature of Business

Range Resources Corporation ("Range," "we," "us," or "our") is a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs"), crude oil and condensate company engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian region of the United States. Our objective is to build stockholder value through returns focused development of natural gas properties. Range is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol "RRC".

(2) Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements, including the notes, have been prepared in accordance with U.S. GAAP and include the accounts of all of our subsidiaries. All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to prior period amounts to conform to the current period's presentation. These reclassifications have no impact on previously reported stockholders' equity, net income or cash flows.

Use of Estimates

The preparation of financial statements in accordance with U.S. GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates and changes in these estimates are recorded when known.

Estimated quantities of natural gas, NGLs, crude oil and condensate reserves is a significant estimate that requires judgment. All of the reserve data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas, NGLs, crude oil and condensate. There are numerous uncertainties inherent in estimating quantities of proved natural gas, NGLs, crude oil and condensate reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of natural gas, NGLs and crude oil and condensate that are ultimately recovered. See Note 17 for further detail.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment, valuation of certain derivative instruments, exit cost liabilities and valuation allowances for deferred income tax assets, among others. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Business Segment Information

We have evaluated how we are organized and managed and have identified only one operating segment. We consider our gathering, processing and marketing functions as integral to our natural gas, crude oil and condensate producing activities. We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We measure financial performance as a single enterprise and not on an area-by-area basis. All of our operating revenues, income from operations and assets are generated and located in the United States.

Revenue Recognition and Accounts Receivable

Natural gas, NGLs and oil sales revenues are recognized when control of the product is transferred to the customer and collectability is reasonably assured. See below for a more detailed summary of our product types.

Natural Gas and NGLs Sales. Under some of our gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity processes the natural gas and remits proceeds to us for the resulting sales of NGLs and residue gas. In these scenarios, we evaluate whether we are the principal or the agent in the transaction. For those contracts that we have concluded that we are the principal, the ultimate third party is our customer and we recognize revenue on a gross basis, with gathering, compression, processing and transportation fees presented as an expense. Alternatively, for those contracts that we have concluded that we are the agent, the midstream processing entity is our customer and we recognize revenue based on the net amount of the proceeds received from the midstream processing entity.

In other natural gas processing agreements, we may elect to take our residue gas and/or NGLs in kind at the tailgate of the midstream entity's processing plant and subsequently market the product on our own. Through the marketing process, we deliver product to the ultimate third-party purchaser at a contractually agreed-upon delivery point and receive a specified index price from the purchaser. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing and compression expense.

Oil Sales. Our oil sales contracts are generally structured in one of the following ways:

- We sell oil production at the wellhead and collect an agreed-upon index price, net of transportation incurred by the purchaser (that is, a netback arrangement). In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead at the net price received.
- We deliver oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title, and risk of loss of the product. Under this arrangement, we pay a third party to transport the product and receive a specified index price from the purchaser with no deduction. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. The third-party costs are recorded as transportation, gathering, processing and compression expense.

Brokered Natural Gas, Marketing and Other. We realize brokered margins as a result of buying natural gas or NGLs utilizing separate purchase transactions, generally with separate counterparties, and subsequently selling that natural gas or NGLs under our existing contracts to fill our contract commitments or use existing infrastructure contracts to economically utilize available capacity. In these arrangements, we take control of the natural gas purchased prior to delivery of that gas under our existing gas contracts with a separate counterparty. Revenues and expenses related to brokering natural gas are reported gross as part of revenues and expenses in accordance with applicable accounting standards. Proceeds generated from the sale of excess firm transportation to third parties is also included here when we are determined to no longer be the primary obligor of such arrangement. Our net brokered margin was a loss of $5.4 million in 2022 compared to income of $1.1 million in 2021 and a loss of $14.2 million in 2020.

The recognition of gains or losses on derivative instruments is not considered revenue from contracts with customers. We may use financial or physical 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 we intend to physically settle but that do not meet all of the criteria to be treated as normal sales.

Accounts Receivable. Our accounts receivable consist mainly of receivables from oil and gas purchasers and joint interest owners on properties we operate. Although receivables are concentrated in the oil and gas industry, we do not view this as an unusual credit risk. However, this concentration has the potential to impact our overall exposure to credit risk in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. Each reporting period, we assess the recoverability of material receivables using historical data and current market conditions. The loss given default method is used when, based on management's judgement, an allowance for expected credit losses is accrued on material receivables to reflect the net amount to be collected. In certain instances, we require purchasers to post stand-by letters of credit. For receivables from joint interest owners, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We regularly review collectability and establish or adjust our allowance as necessary. We have allowances for doubtful accounts relating to exploration and production receivables of $314,000 at December 31, 2022 compared to $568,000 at December 31, 2021. We recorded a reduction in our debt expense of $250,000 in the year ended December 31, 2022 compared to debt expense of $200,000 in the year ended December 31, 2021 and debt expense of $400,000 in the year ended December 31, 2020.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less. Outstanding checks in excess of funds on deposit are included in accounts payable on the consolidated balance sheets and the change in such overdrafts is classified as a financing activity on the consolidated statements of cash flows.

Marketable Securities

Investments in unaffiliated equity securities held in our deferred compensation plans qualify as trading securities and are recorded at fair value. Investments held in the deferred compensation plans consist of various publicly-traded mutual funds. These funds include equity securities and money market instruments and are reported in other assets in the accompanying consolidated balance sheets.

Natural Gas and Oil Properties

Property Acquisition Costs. We use the successful efforts method of accounting for natural gas and oil producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of proved properties, including other property and equipment such as gathering lines related to natural gas and oil producing activities, is provided on the units of production method. Historically, we have adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs.

Impairments. Our proved natural gas and oil properties are reviewed for impairment of value whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying value of the asset, an impairment loss is recognized based on the fair value of the asset. These assets are reviewed for potential impairment at the lowest level for which there are identifiable cash flows that are largely independent of other groups of assets which is the level at which depletion is calculated. Natural gas and oil properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. There were no indicators of proved property impairment identified in 2022 or 2021. Proved property impairment recorded in the year ended December 31, 2020 reduced the carrying value of our North Louisiana properties to the anticipated sales proceeds.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and evaluated (at least quarterly) as to recoverability based on changes brought about by economic factors and potential shifts in business strategy employed by management which could impact the number of drilling locations we intend to drill. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Information such as reservoir performance or future plans to develop acreage is also considered. Impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. Unproved properties had a net book value of $800.6 million as of December 31, 2022 compared to $837.3 million in 2021. We have recorded abandonment and impairment expense related to unproved properties of $28.6 million in the year ended December 31, 2022 compared to $7.2 million in 2021 and $19.3 million in 2020.

Dispositions. Proceeds from the disposal of natural gas and oil producing properties that are part of an amortization base are credited to the net book value of the amortization group with no immediate effect on income. However, gain or loss is recognized if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. Dispositions are accounted for as a sale of assets. For additional information regarding our dispositions, see Note 3.

Other Property and Equipment

Other property and equipment includes assets such as buildings, furniture and fixtures, field equipment, leasehold improvements and data processing and communication equipment. These items are generally depreciated by individual components on a straight-line basis over their economic useful life, which is generally from three to ten years. Leasehold improvements are amortized over the lesser of their economic useful lives or the underlying terms of the associated leases. Depreciation expense was $2.2 million in the year ended December 31, 2022 compared to $2.4 million in the year ended December 31, 2021 and $2.6 million in the year ended December 31, 2020.

Leases

We determine if an arrangement is a lease at the inception of the arrangement. We lease certain drilling rigs, office space, field equipment, vehicles and other equipment under cancelable and non-cancelable leases to support our operations. Certain of our lease agreements include lease and non-lease components. We account for these components as a single lease. Lease costs associated with drilling rigs are capitalized as part of well costs.

Lease right-of-use ("ROU") assets and liabilities are initially recorded on the lease commencement date based on the present value of lease payments over the lease term. As most of our lease contracts do not provide an implicit discount rate, we use our incremental borrowing rate which is determined based on information available at the commencement date of a lease. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. The exercise of those options is at our discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with a term of 12 months or less are not recorded as a right-of-use asset and liability. The majority of our leases are classified as either short-term or long-term operating leases.

Our leased assets may be used in joint oil and gas operations with other working interest owners. We recognize lease liabilities and ROU assets only when we are the signatory to a contract as an operator of joint properties. Such lease liabilities and ROU assets are determined and disclosed based on gross contractual obligations. Our lease costs are also presented on a gross contractual basis.

Other Assets

Other assets at December 31, 2022 include $57.7 million of marketable securities held in our deferred compensation plans and $10.4 million of other investments. Other assets at December 31, 2021 included $69.6 million of marketable securities held in our deferred compensation plans, $11.5 million of other investments and $5.2 million of deferred financing costs primarily related to our bank credit facility.

Stock-based Compensation Arrangements

We account for stock-based compensation under the fair value method of accounting. We grant various types of stock-based awards including restricted stock and performance-based awards. The fair value of our restricted stock awards and our performance-based awards (where the performance condition is based on internal performance metrics) is based on the market value of our common stock on the date of grant. The fair value of our performance-based awards where the performance condition is based on market conditions is estimated using a Monte Carlo simulation method.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. If actual forfeitures are different than expected, adjustments to recognize expense may be required in future periods. To the extent possible, we limit the amount of shares to be issued for these awards by satisfying tax withholding requirements with cash. All awards have been issued at prevailing market prices at the time of grant and the vesting of these awards is based on an employee's continued employment with us, with the exception of employment termination due to death, disability or retirement. For additional information regarding stock-based compensation, see Note 11.

Derivative Financial Instruments

All of our commodity derivative instruments are issued to manage the price risk attributable to our expected natural gas, NGLs and oil production. While there is risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are important. Among these benefits are more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital and better access to bank and other capital markets. All unsettled commodity derivative instruments are recorded in the accompanying consolidated balance sheets as either an asset or a liability measured at their fair value. In most cases, our derivatives are reflected on our consolidated balance sheets on a net basis by brokerage firm when they are governed by master netting agreements, which in an event of default, allows us to offset payables to and receivables from the defaulting counterparty. Changes in a derivative's fair value are recognized in earnings. Cash flows from derivative contract settlements are reflected in operating activities in the accompanying consolidated statements of cash flows.

All realized and unrealized gains and losses on derivative instruments are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in each period in derivative fair value in the accompanying consolidated statements of operations. Certain of our commodity derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. We have collars which establish a minimum floor price and a predetermined ceiling price. We also have entered into basis swap agreements. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into natural gas basis swap agreements that effectively fix our basis adjustments. Our program may also include a three-way collar which is a combination of three options: a sold call, a purchased put and a sold put. The sold call establishes the ceiling price while the purchased put establishes the floor price until the market price for the commodity falls below the sold put stock price at which time the value of the purchased put is effectively capped. We also have the right to receive contingent consideration related to the sale of our North Louisiana assets in 2020. This derivative financial instrument is recorded as an asset in the accompanying consolidated balance sheets. This contingent consideration is based on future natural gas, NGLs and oil prices primarily based on published indexes. For additional information regarding our derivative instruments, see Note 9.

From time to time, we may enter into derivative contracts and pay or receive premium payments at the inception of the derivative contract which represent the fair value of the contract at its inception. These amounts would be included within the net derivative asset or liability on our consolidated balance sheets. The amounts paid or received for derivative premiums reduce or increase the amount of gains and losses that are recorded in the earnings each period as the derivative contracts settle. We did not materially modify any existing derivative contracts in 2022, 2021 or 2020.

Concentrations of Credit Risk

As of December 31, 2022, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of counterparties' failure to perform under derivative contracts. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions, commodity traders and end-users in various industries and such receivables are generally unsecured. The nature of our customers' businesses may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. To manage risks of collecting accounts receivable, we monitor our counterparties' financial strength and/or credit ratings and where we deem necessary, we obtain parent company guarantees, prepayments, letters of credit or other credit enhancements to reduce risk of loss. We do not anticipate a material impact on our financial results due to non-performance by third parties.

For the year ended December 31, 2022, we had no customer that accounted for 10% or more of natural gas, NGLs and oil sales compared to one customer for the year ended December 31, 2021 and none for the year ended December 31, 2020. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil production.

We have executed International Swap Dealers Association Master Agreements ("ISDA Agreements") with counterparties for the purpose of entering into derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor counterparties based on assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. Additionally, the terms of our ISDA Agreements provide us and our counterparties with netting rights such that we may offset payables against receivables with a counterparty under separate derivative contracts. Our ISDA Agreements also generally contain set-off rights such that, upon the occurrence of defined acts of default by either us or a counterparty to a derivative contract, the non-defaulting party may set-off receivables owed under all derivative contracts against payables from other agreements with that counterparty. None of our derivative contracts have a margin requirement or collateral provision that would require us to fund or post additional collateral prior to the scheduled cash settlement date.

At December 31, 2022, our derivative counterparties included fourteen financial institutions and commodity traders, of which all but six are secured lenders in our bank credit facility. At December 31, 2022, our net derivative liability includes a payable to four counterparties not included in our bank credit facility totaling $4.0 million and a receivable from the remaining two counterparties of $3.3 million. In determining fair value of derivative assets, we evaluate the risk of non-performance and incorporate factors such as amounts owed under other agreements permitting set-off, as well as pricing of credit default swaps for the counterparty. Historically, we have not experienced any issues of non-performance by derivative counterparties. Net derivative liabilities are determined in part by using our market based credit spread to incorporate our theoretical risk of non-performance.

Asset Retirement Obligations

The fair value of asset retirement obligations ("ARO") is recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of natural gas and oil producing properties and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience of plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates of the cost to plug and abandon the wells in the future, federal and state regulatory requirements, inflation rates and credit-adjusted-risk-free interest rates. Depreciation of capitalized asset retirement costs will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets. See Note 8 for additional information.

Exit Costs

We recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. The recognition and fair value estimation of an exit cost liability requires that management take into account certain estimates and assumptions. Fair value estimates are based on future discounted cash outflows required to satisfy the obligation. In periods subsequent to initial measurement, changes to an exit cost liability, including changes resulting from revisions to either the timing or the amount of estimated cash flows over the future contract period, are recognized as an adjustment to the liability in the period of the change utilizing the initial discount rate. These costs, including associated accretion expense, are included in exit and termination costs in the accompanying consolidated statements of operations. See Note 15 for additional information.

Contingencies

We are subject to legal proceedings, claims, and liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated. See Note 14 for a more detailed discussion regarding our contingencies.

Environmental Costs

Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. Expenditures that relate to an existing condition caused by past operations that have no future economic benefits are expensed.

Deferred Taxes

Deferred tax assets and liabilities, measured by the enacted tax rates, are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors may include whether we are in a cumulative loss position in recent years, our reversal of temporary differences and our expectation to generate sufficient taxable income in the periods before tax credits and operating loss carryforwards expire. All deferred taxes are classified as long-term in the accompanying consolidated balance sheets.

Treasury Stock

Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

(3) Dispositions

We recognized a pretax net gain on the sale of assets of $409,000 in the year ended December 31, 2022 compared to $701,000 in 2021 and $110.8 million in 2020. The following describes the significant divestitures that are included in our consolidated results of operations for each of years in the three-year period ended December 31, 2022.

2021 Dispositions

North Louisiana. As described below, we completed the sale of our North Louisiana assets in third quarter 2020. In 2021, we recognized an additional gain on the sale of these assets of $479,000 which includes a gain of $1.9 million primarily related to final closing adjustments partially offset by a $1.5 million loss on settlement of royalty claims.

2020 Dispositions

North Louisiana. In third quarter 2020, we completed the sale of our North Louisiana assets for total consideration having an estimated fair value of $260.0 million. This estimated fair value reflects (i) cash proceeds of $245.0 million, before normal closing adjustments and (ii) $15.0 million in contingent consideration which represents the estimated fair value, on August 14, 2020, of the contingent consideration we are entitled to receive in the future should certain commodity price thresholds be met. During 2020, we recorded a pretax loss of $9.5 million, after closing adjustments and transaction costs. The sale included:

- *Divestiture contingent consideration.* We are entitled to receive contingent consideration, annually through 2023, based on future realization of certain natural gas and oil prices based on published indexes along with the realized NGLs price of the buyer. The fair value of the contingent consideration is classified as a noncurrent derivative asset on our consolidated balance sheets. We revalue the contingent consideration each reporting period, with any valuation changes being recorded as derivative fair value income or loss in our consolidated statements of operations. See also Note 9 and Note 10 for additional information.
- *Divestiture contract obligation.* As part of this sale, we retained certain midstream gathering, transportation and processing obligations through 2030. The divestiture contract obligation is included in current or non-current liabilities in our consolidated balance sheets based on the forecasted timing of payments. These costs, along with

accretion expense and any adjustments to this obligation, are recognized in exit and termination costs in our consolidated statements of operations. See also Note 10, Note 14 and Note 15 for additional information.

Pennsylvania. In first quarter 2020, we completed the sale of our shallow legacy assets in Northwest Pennsylvania for proceeds of $1.0 million. Based upon the receipt of approval from state governmental authorities of a change in operatorship during that quarter, we recognized a pretax gain of $122.5 million primarily due to the elimination of the asset retirement obligation associated with these properties.

(4) Revenues from Contracts with Customers

Disaggregation of Revenue

We have identified three material revenue streams in our business: natural gas sales, NGLs sales, crude oil and condensate sales. Brokered revenue attributable to each product sales type is included here because the volume of product that we purchase is subsequently sold to separate counterparties in accordance with existing sales contracts under which we also sell our production. Revenue attributable to each of our identified revenue streams is disaggregated below (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Natural gas sales	$ 3,364,111	$ 1,896,231	$ 943,740
NGLs sales	1,308,574	1,135,826	578,454
Oil and condensate sales	238,407	182,970	85,519
Total natural gas, NGLs and oil sales	4,911,092	3,215,027	1,607,713
Sales of purchased natural gas	408,584	342,431	160,122
Sales of purchased NGLs	2,783	6,925	3,776
Other marketing revenue and other income	12,850	16,056	9,375
Total	$ 5,335,309	$ 3,580,439	$ 1,780,986

Performance Obligations and Contract Balance

A significant number of our product sales are short-term in nature with a contract term of one year or less. We typically satisfy our performance obligation upon transfer of control and record revenue in the month production is delivered to the purchaser. Settlement statements for certain gas and NGLs sales may be received 30 to 90 days after the date production is delivered, and as a result, we are required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts for product sales in the month that payment is received from the purchaser. We have internal controls in place for our estimation process and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the three years ended December 31, 2022, 2021 and 2020, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. Under our sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities. Accounts receivable attributable to our revenue contracts with customers was $463.3 million at December 31, 2022 compared to $460.2 million at December 31, 2021.

(5) Income Taxes

Our income tax expense was $230.5 million for the year ended December 31, 2022 compared to a benefit of $9.7 million in 2021 and a benefit of $25.6 million in 2020. The effective income tax rate is influenced by a variety of factors including geographic sources and relative magnitude of these sources of income. Reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2022	2021	2020
Federal statutory tax rate	21.0%	21.0%	21.0%
State, net of federal benefit	1.0	4.0	5.2
State rate and law change	—	(3.4)	4.3
Equity compensation	—	2.3	(1.0)
Valuation allowances	(5.5)	(26.8)	(25.9)
Permanent differences and other	(0.2)	0.5	(0.1)
Consolidated effective tax rate	16.3%	(2.4)%	3.5%

Income tax expense (benefit) attributable to income (loss) before income taxes consists of the following (in thousands):

	2022			2021			2020		
	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
U.S. federal	$ —	$ 245,839	$ 245,839	$ —	$ 6,297	$ 6,297	$ (366)	$ (24,489)	$ (24,855)
U.S. state and local	14,688	(30,067)	(15,379)	7,984	(24,024)	(16,040)	(157)	(540)	(697)
Total	$ 14,688	$ 215,772	$ 230,460	$ 7,984	$ (17,727)	$ (9,743)	$ (523)	$ (25,029)	$ (25,552)

Significant components of deferred tax assets and liabilities are as follows:

	December 31,	
	2022	2021
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforward	$ 581,349	$ 788,375
Divestiture contract obligation	105,227	112,199
Deferred compensation	25,733	22,121
Equity compensation	4,813	4,833
Asset retirement obligations	24,113	21,734
Interest expense carryforward	16,118	53,876
Lease right-of-use liabilities	19,395	9,954
Cumulative mark-to-market loss	30,307	32,221
Other	16,922	12,181
Valuation allowances:		
Federal	(21,320)	(67,984)
State, net of federal benefit	(171,423)	(203,085)
Total deferred tax assets	631,234	786,425
Deferred tax liabilities:		
Depreciation and depletion	(935,710)	(879,163)
Lease right-of-use assets	(18,440)	(9,247)
Other	(10,655)	(15,657)
Total deferred tax liabilities	(964,805)	(904,067)
Net deferred tax liability	$ (333,571)	$ (117,642)

At December 31, 2022, deferred tax liabilities exceeded deferred tax assets by $333.6 million. As of December 31, 2022, we have a state valuation allowance of $171.4 million related to state tax attributes in Louisiana, Oklahoma, Pennsylvania, Texas and West Virginia. As of December 31, 2022, we have federal valuation allowances of $21.3 million primarily related to our federal basis differences. The net change in our deferred tax asset valuation allowances was a reduction of $78.3 million for the year ended December 31, 2022 compared to a reduction in our valuation allowances of $108.0 million in 2021 and an increase of $188.2 million in 2020. We continue to evaluate the realizability of our federal and state deferred tax assets and, in 2022, based upon significant increases in commodity prices, our 2022 results and other positive evidence, we released a significant portion of our federal and state valuation allowances.

At December 31, 2022, we had federal NOL carryforwards of $2.0 billion. This includes $374.5 million that expires in 2036 and 2037 and also includes $1.7 billion of NOL carryforwards generated after 2017 that do not expire. We have state NOL carryforwards in Pennsylvania of $825.9 million that expire between 2031 and 2042 and in Louisiana, we have state NOL carryforwards of $1.6 billion that do not expire. We file a consolidated tax return in the United States federal jurisdiction. We file separate company state income tax returns in Louisiana and Pennsylvania and file consolidated or unitary state income tax returns in Oklahoma, Texas and West Virginia. We are subject to U.S. federal income tax examinations for the years 2018 and after and we are subject to various state tax examinations for years 2018 and after. We have not extended the statute of limitation period in any income tax jurisdiction. Our policy is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any material accrued interest or penalties related to tax amounts as of December 31, 2022 or December 31, 2021. Throughout 2022, 2021 and 2020, our unrecognized tax benefits were not material.

On July 12, 2022, the Commonwealth of Pennsylvania enacted legislation to reduce the corporate net income tax rate from 9.99% to 8.99% in 2023 and continues to reduce that rate by 0.5% per year beginning in 2024, with the rate becoming 4.99% in 2031 and each year thereafter. We recorded a $20.7 million tax benefit in third quarter 2022 for the impact of this tax rate reduction which is reflected as a reduction to our Pennsylvania valuation allowance.

On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 ("IRA") into law. The IRA contains a number of revisions to the Internal Revenue Code, including a 15% corporate minimum income tax for tax years beginning after December 31, 2022. While these tax law changes have no immediate effect and are not expected to have a material adverse effect on our results of operations going forward, we will continue to evaluate their impact as further information becomes available.

(6) Net Income (Loss) per Common Share

Basic income or loss per share attributable to common stockholders is computed as (i) income or loss attributable to common stockholders (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common stockholders is computed as (i) basic income or loss attributable to common stockholders (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding. Diluted net income (loss) per share is calculated under both the two class method and the treasury stock method and the more dilutive of the two calculations is presented. The following table sets forth a reconciliation of net income or loss to basic income or loss attributable to common stockholders and to diluted income or loss attributable to common stockholders (in thousands except per share amounts):

	Year Ended December 31,		
	2022	2021	2020
Net income (loss), as reported	$ 1,183,370	$ 411,778	$ (711,777)
Participating basic earnings [a]	(28,578)	(10,795)	—
Basic net income (loss) attributed to common stockholders	1,154,792	400,983	(711,777)
Reallocation of participating earnings [a]	614	272	—
Diluted net income (loss) attributed to common stockholders	$ 1,155,406	$ 401,255	$ (711,777)
Net income (loss) per common share:			
Basic	$ 4.79	$ 1.65	$ (2.95)
Diluted	$ 4.69	$ 1.61	$ (2.95)

[a] Restricted stock Liability Awards represent participating securities because they participate in nonforfeitable dividends or distributions with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Participating securities, however, do not participate in undistributed net losses.

The following table details basic weighted average common shares outstanding and diluted weighted average common shares outstanding (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Denominator:			
Weighted average common shares outstanding – basic	240,858	242,862	241,373
Effect of dilutive securities	5,521	6,452	—
Weighted average common shares outstanding – diluted	246,379	249,314	241,373

Weighted average common shares outstanding – basic excludes 6.1 million shares of restricted stock Liability Awards held in our deferred compensation plans (although all awards are issued and outstanding upon grant) for the period ending December 31, 2022 compared to 6.5 million shares for the period ending December 31, 2021 and 5.5 million shares for the period ending December 31, 2020. Due to our net loss for the year ended December 31, 2020, we excluded all outstanding equity grants from the computation of diluted net loss per share because the effect would have been anti-dilutive to the computations. Equity grants of 5,000 shares for the year ended December 31, 2022 and equity grants of 18,000 shares for the year ended December 31, 2021 were outstanding but not included in the computation of diluted net income because the grant prices were greater than the average market price of the common shares and would be anti-dilutive to the computations.

(7) Indebtedness

We had the following debt outstanding as of the dates shown below. The expenses of issuing debt are generally capitalized and included as a reduction to debt in the accompanying consolidated balance sheets. These costs are amortized over the expected life of the related instruments. When debt is retired before maturity, or modifications significantly change the cash flows, the related unamortized costs are expensed. For December 31, 2021, deferred financing costs for our bank credit facility are included in other assets in the accompanying consolidated balance sheet. No interest was capitalized in the three-year period ended December 31, 2022. The components of our debt outstanding, including the effects of debt issuance costs, is as follows (in thousands):

	December 31, 2022	December 31, 2021
Bank debt	$ 19,000	$ —
Senior notes		
4.75% senior notes due 2030	500,000	—
4.875% senior notes due 2025	750,000	750,000
5.00% senior notes due 2022	—	169,589
5.00% senior notes due 2023	—	532,335
5.875% senior notes due 2022	—	48,528
8.25% senior notes due 2029	600,000	600,000
9.25% senior notes due 2026	—	850,000
Total senior notes	1,850,000	2,950,452
Total debt	1,869,000	2,950,452
Unamortized premium	—	188
Unamortized debt issuance costs	(27,040)	(24,853)
Total debt (net of debt issuance costs)	1,841,960	2,925,787
Less current maturities of long-term debt	—	(218,017)
Total long-term debt	$ 1,841,960	$ 2,707,770

Bank Debt

In April 2022, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, and is secured by substantially all of our assets and has a maturity date of April 14, 2027. The bank credit facility provides for a maximum facility amount of $4.0 billion and an initial borrowing base of $3.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations and for event-driven unscheduled redeterminations. Our current bank group is composed of seventeen financial institutions. The borrowing base may be increased or decreased based on our request and sufficient proved reserves, as determined by the bank group. The commitment amount may be increased to the borrowing base, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. Borrowings under the bank facility can either be at the alternate base rate ("ABR," as defined in the bank credit agreement) plus a spread ranging from 0.75% to 1.75% or at the secured overnight financing rate ("SOFR"), as defined in the bank credit agreement) plus a spread ranging from 1.75% to 2.75%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our SOFR loans to ABR loans or to convert all or any part of our ABR loans to SOFR loans. The weighted average interest rate was 4.1% for the year ended December 31, 2022 compared to 2.1% for the year ended December 31, 2021 and 2.6% for the year ended December 31, 2020. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At December 31, 2022, the commitment fee was 0.375%, the interest rate margin was 0.75% on our ABR loans and 1.75% on our SOFR loans.

On December 31, 2022, bank commitments totaled $1.5 billion and we had outstanding borrowings under our bank credit facility of $19.0 million. Additionally, we had $307.4 million of undrawn letters of credit leaving $1.2 billion of committed borrowing capacity available under the facility. As part of our redetermination completed in September 2022, our borrowing base was reaffirmed for $3.0 billion and our bank commitment was also reaffirmed at $1.5 billion.

New Senior Notes

In January 2022, we issued $500.0 million aggregate principal amount of 4.75% senior notes due 2030 (the "4.75% Notes") for an estimated net proceeds of $492.5 million after underwriting discounts and commissions of $7.5 million. The notes were issued at par. The 4.75% Notes were offered to qualified institutional buyers and to non-U.S. persons outside the United States in compliance with Rule 144A (for life) and Regulation S under the Securities Act. Interest due on the 4.75% Notes is payable semi-annually in February and August and is unconditionally guaranteed on a senior unsecured basis by all of our subsidiary guarantors. On or after February 1, 2027, we may redeem the 4.75% Notes, in whole or in part and from time to time, at 100% of the principal amounts plus accrued and unpaid interest. We may redeem the notes prior to their maturity at redemption prices based on a premium, plus accrued and unpaid interest as described in the indenture governing the 4.75% Notes. Upon occurrence of certain changes in control, we must offer to repurchase the 4.75% Notes. The 4.75% Notes are unsecured and are subordinated to all of our existing and future secured debt, rank equally with all of our existing and future unsecured debt and rank senior to all of our existing and future subordinated debt. On the closing of the 4.75% Notes, we used these proceeds, along with cash on hand and our bank credit facility to redeem $850.0 million of our 9.25% senior notes due 2026.

Early Extinguishment of Debt in 2022

In January 2022, we announced a call for the redemption of $850.0 million of our outstanding 9.25% senior notes due 2026 at a price of 106.938% of par plus accrued and unpaid interest, which were redeemed on February 1, 2022. For the year ended December 31, 2022, we recorded a loss on early extinguishment of debt of approximately $69.2 million, including transaction call premium costs and the expensing of the remaining deferred financing costs on the repurchased debt.

Senior Note Redemptions

If we experience a change of control, noteholders may require us to repurchase all or a portion of our senior notes at 101% of the principal amount plus accrued and unpaid interest, if any. We currently intend to retire our outstanding long-term debt as it matures, is callable or when market conditions are favorable to repurchase in the open market.

In second quarter 2022, we retired our 5.00% senior notes due 2022 and our 5.875% senior notes due 2022 on their maturity dates. In third quarter 2022, we purchased in the open market $3.8 million aggregate principal amount of our 5.00% senior notes due 2023. In fourth quarter 2022, we announced a call for the redemption of the remaining 5.00% senior notes due 2023 at par and we recognized a loss on early extinguishment of debt of $261,000 reflecting the expensing of the remaining deferred financing costs.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our wholly-owned subsidiaries, which are directly or indirectly owned by Range, of our senior notes and our bank credit facility are full and unconditional and joint and several, subject to certain customary release provisions. The assets, liabilities and results of operations of Range and our guarantor subsidiaries are not materially different than our consolidated financial statements. A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person (including an unrestricted subsidiary of Range) by way of merger, consolidation, or otherwise; or
- if Range designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

Debt Covenants and Maturity

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make certain investments. We are required to maintain a ratio of EBITDAX (as defined in the credit agreement) of 3.75x and a minimum current ratio (as defined in the credit agreement) of 1.0x. We were in compliance with applicable covenants under the bank credit facility at December 31, 2022. The following is the principal maturity schedule for our long-term debt outstanding as of December 31, 2022 (in thousands):

	Year Ended December 31,
2023	$ —
2024	—
2025	750,000
2026	—
2027	19,000
Thereafter	1,100,000
	$ 1,869,000

(8) Asset Retirement Obligations

ARO primarily represents the present value of the estimated amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well lives. The inputs are calculated based on historical data as well as current estimated costs. The following is a reconciliation of our liability for plugging and abandonment costs as of December 31, 2022 and 2021 (in thousands):

	2022	2021
Beginning of period	$ 95,836	$ 79,822
Liabilities incurred	2,589	73
Liabilities settled	(10,650)	(8,197)
Accretion expense	6,569	5,511
Change in estimate	15,507	18,627
End of period	109,851	95,836
Less current portion	(4,570)	(5,310)
Long-term asset retirement obligations	$ 105,281	$ 90,526

Accretion expense is recognized as an increase to depreciation, depletion and amortization expense in the accompanying consolidated statements of operations.

(9) Derivative Activities

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swaps or collar contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. Every derivative instrument is required to be recorded on our consolidated balance sheets as either an asset or a liability measured at its fair value. Their fair value, which is represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price (generally NYMEX for natural gas and crude oil), approximated a net derivative liability of $138.6 million at December 31, 2022. These contracts expire monthly through December 2024. The following table sets forth the derivative volumes by year as of December 31, 2022, excluding our basis and divestiture contingent consideration which are discussed separately below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price			
			Swap	Sold Put	Floor	Ceiling
Natural Gas						
2023	Swaps	376,384 Mmbtu/day	$ 3.44			
2023	Collars	278,082 Mmbtu/day			$ 3.60	$ 4.78
2023	Three-way Collars	187,233 Mmbtu/day		$ 2.67	$ 3.74	$ 4.83
2024	Swaps	110,000 Mmbtu/day	$ 4.63			
2024	Collars	469,235 Mmbtu/day			$ 3.55	$ 5.51
Crude Oil						
2023	Swaps	5,123 bbls/day	$ 71.39			
January-September 2024	Collars	832 bbls/day			$ 80.00	$ 90.12

Basis Swap Contracts

In addition to the swaps and collars above, at December 31, 2022, we had natural gas basis swap contracts which lock in the differential between NYMEX and certain of our physical pricing points in Appalachia. These contracts settle monthly through December 2026 and include a total volume of 288,555,000 Mmbtu. The fair value of these contracts was a net derivative asset of $521,000 on December 31, 2022.

Divestiture Contingent Consideration

In addition to the derivatives described above, our right to receive contingent consideration in conjunction with the sale of our North Louisiana assets was determined to be a derivative financial instrument that is not designated as a hedging instrument. The contingent consideration of up to $21.0 million is based on future realization of natural gas and oil prices based on published indexes and realized NGLs prices of the buyer for the year ending 2023. All changes in the fair value are recognized as a gain or loss in earnings in the period they occur in derivative fair value income or loss in our consolidated statements of operations. The fair value of this instrument on December 31, 2022 was a derivative asset of $13.1 million. In addition, we currently expect to receive $24.5 million for the year ended December 31, 2022 which is reflected in current assets in the accompanying consolidated balance sheet and represents the maximum contingent payment amount for 2022.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of December 31, 2022 and 2021 is summarized below (in thousands). As of December 31, 2022, we are conducting derivative activities with fourteen counterparties, of which all but six are secured lenders in our bank credit facility. We believe all of these counterparties are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements.

		December 31, 2022		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 19,438	$ (6,236)	$ 13,202
	–collars	54,222	(45,452)	8,770
	–three-way collars	12,424	(12,424)	—
	–basis swaps	25,493	(20,437)	5,056
Crude oil	–collars	1,807	—	1,807
Divestiture contingent consideration		13,080	—	13,080
		$ 126,464	$ (84,549)	$ 41,915

		December 31, 2022		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$ (115,374)	$ 6,236	$ (109,138)
	–collars	(72,866)	45,452	(27,414)
	–three-way collars	(24,341)	12,424	(11,917)
	–basis swaps	(24,972)	20,437	(4,535)
Crude oil	–swaps	(13,908)	—	(13,908)
		$ (251,461)	$ 84,549	$ (166,912)

		December 31, 2021		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 22,491	$ (18,111)	$ 4,380
	–collars	12,378	(8,600)	3,778
	–three-way collars	12,234	(8,449)	3,785
	–basis swaps	18,092	(10,487)	7,605
Crude oil	–swaps	368	(2,153)	(1,785)
NGLs	–C3 propane spread	4,153	(4,153)	—
	–C5 natural gasoline swaps	266	(363)	(97)
	–C5 natural gasoline collars	221	(221)	—
Freight	–swaps	114	(81)	33
Divestiture contingent consideration		26,640	—	26,640
		$ 96,957	$ (52,618)	$ 44,339

		December 31, 2021		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$ (121,759)	$ 18,111	$ (103,648)
	–swaptions	(11,149)	—	(11,149)
	–collars	(16,579)	8,600	(7,979)
	–three-way collars	(37,166)	8,449	(28,717)
	–calls	(61)	—	(61)
	–basis swaps	(2,064)	10,487	8,423
Crude oil	–swaps	(27,252)	2,153	(25,099)
NGLs	–C3 propane spread	(4,030)	4,153	123
	–C5 natural gasoline swaps	(2,048)	363	(1,685)
	–C5 natural gasoline collars	(1,493)	221	(1,272)
Freight	–swaps	—	81	81
		$ (223,601)	$ 52,618	$ (170,983)

The effects of our derivatives on our consolidated statements of operations for the last three years are summarized below (in thousands).

	Derivative Fair Value (Loss) Income		
	Year Ended December 31,		
	2022	2021	2020
Commodity swaps	$ (713,122)	$ (466,203)	$ 158,248
Swaptions	11,149	(1,346)	(4,955)
Collars	(302,364)	(117,612)	3,304
Three-way collars	(235,335)	(137,443)	(16,346)
Basis swaps	41,622	33,691	48,278
Calls	(1,363)	(836)	(558)
Freight swaps	(33)	(647)	(1,230)
Divestiture contingent consideration	10,940	40,180	970
Total	$ (1,188,506)	$ (650,216)	$ 187,711

(10) Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy, while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 – Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimates of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments using standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. When transfers between levels occur, it is our policy to assume the transfer occurred at the date of the event or change in circumstances that caused the transfer.

Fair Values-Recurring

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following tables present the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

		Fair Value Measurements at December 31, 2022 Using:			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2022
Trading securities held in the deferred compensation plans		$ 57,717	$ —	$ —	$ 57,717
Derivatives	–swaps	—	(109,844)	—	(109,844)
	–collars	—	(16,837)	—	(16,837)
	–three-way collars	—	(11,917)	—	(11,917)
	–basis swaps	—	521	—	521
Divestiture contingent consideration		—	13,080	—	13,080

		Fair Value Measurements at December 31, 2021 Using:			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2021
Trading securities held in the deferred compensation plans		$ 69,606	$ —	$ —	$ 69,606
Derivatives	–swaps	—	(127,934)	—	(127,934)
	–calls	—	(61)	—	(61)
	–collars	—	(4,201)	(1,272)	(5,473)
	–three-way collars	—	(24,932)	—	(24,932)
	–basis swaps	—	16,151	—	16,151
	–swaptions	—	—	(11,149)	(11,149)
Derivatives	–freight swaps	—	114	—	114
Divestiture contingent consideration		—	26,640	—	26,640

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2022 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. Derivatives in Level 3 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes but will also utilize unobservable pricing inputs that are significant to overall value. At December 31, 2022, we have no Level 3 measurements. The following is a reconciliation of the beginning and ending balances for derivative instruments classified as Level 3 in the fair value hierarchy (in thousands):

	Year Ended December 31, 2022
Balance at December 31, 2021	$ (12,421)
Settlements	1,272
Transfers out of Level 3	11,149
Balance at December 31, 2022	$ —

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains/losses are included in deferred compensation plan expense in the accompanying consolidated statements of operations. For the year ended December 31, 2022, interest and dividends were $1.1 million and mark-to-market was a loss of $14.2 million. For the year ended December 31, 2021, interest and dividends were $951,000 and mark-to-market was a gain of $3.0 million. For the year ended December 31, 2020, interest and dividends were $713,000 and mark-to-market was a gain of $6.3 million.

North Louisiana divestiture contingent consideration. In August 2020, we completed the sale of our North Louisiana assets where we are entitled to receive contingent consideration, based on future realization of natural gas and oil prices based on published indexes along with NGLs prices based on the realized NGLs prices of the buyer. We use an option pricing model to estimate the fair value of the contingent consideration using significant Level 2 inputs that include quoted future commodity prices based on active markets. See also Note 3 and Note 9 for additional information.

North Louisiana divestiture contract obligation. In 2020, we recorded a divestiture contract obligation in conjunction with the sale of our North Louisiana assets. The fair value of this obligation was determined as of the closing date using Level 3 inputs based on a probability-weighted forecast that considers historical results, market conditions and various potential development plans of the buyer to arrive at the estimated present value of the future payments. Inherent in this fair value calculation were numerous other assumptions and judgements including the credit-adjusted discount rate as well as the development plans of the buyer and our probability weighted forecast of those drilling plans, market conditions and the ultimate usage by the buyer of each facility included in the agreement, all of which are inherently uncertain and can alter the amount and timing of future payments. A significant portion of this obligation is a gas processing agreement that includes a deficiency payment if the minimum volume commitment is not met. The present value of future cash payments was determined using a 12 percent discount rate. See also Note 15 for additional information.

Leases. As part of our ongoing effort to reduce general and administrative expense due to both the lower commodity price environment and in conjunction with the sale of our North Louisiana assets, we vacated one floor in our Fort Worth headquarters. We recorded an impairment related to this lease of $2.0 million which is included in impairment of proved property and other assets in our consolidated statement of operations for the year ended December 31, 2020.

Fair Values-Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of December 31, 2022 and 2021 (in thousands):

	December 31, 2022		December 31, 2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and basis swaps	$ 28,835	$ 28,835	$ 17,699	$ 17,699
Divestiture contingent consideration	13,080	13,080	26,640	26,640
Marketable securities [(a)]	57,717	57,717	69,606	69,606
(Liabilities):				
Commodity swaps, collars and basis swaps	(166,912)	(166,912)	(170,983)	(170,983)
Bank credit facility [(b)]	(19,000)	(19,000)	—	—
5.00% senior notes due 2022 [(b)]	—	—	(169,589)	(171,488)
5.875% senior notes due 2022 [(b)]	—	—	(48,528)	(48,955)
5.00% senior notes due 2023 [(b)]	—	—	(532,335)	(543,471)
4.875% senior notes due 2025 [(b)]	(750,000)	(714,870)	(750,000)	(776,153)
9.25% senior notes due 2026 [(b)]	—	—	(850,000)	(916,929)
8.25% senior notes due 2029 [(b)]	(600,000)	(618,312)	(600,000)	(669,648)
4.75% senior notes due 2030 [(b)]	(500,000)	(442,350)	—	—
Deferred compensation plan [(c)]	(189,241)	(189,241)	(165,395)	(165,395)

(a) Marketable securities, which are held in our deferred compensation plans, are actively traded on major exchanges and are updated based on end of period closing prices which is a Level 1 input.

(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior notes is based on end of period market quotes which are Level 2 inputs.

(c) The fair value of our deferred compensation plan is updated at the closing price on the balance sheet date which is a Level 1 input.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical incurrence of and expected future insignificance of bad debt expense. Non-financial liabilities initially measured at fair value include asset retirement obligations, operating lease liabilities and the divestiture contract obligation that we incurred in conjunction with the sale of our North Louisiana assets.

(11) Stock-Based Compensation Plans

Description of the Plans

We have two active equity-based stock plans, our Amended and Restated 2005 Equity-Based Compensation Plan, which we refer to as the 2005 Plan and the Amended and Restated 2019 Equity-Based Compensation Plan, which we refer to as the 2019 Plan. Under these plans, the Compensation Committee of the board of directors may grant, various awards to non-employee directors and employees. Shares issued as a result of awards granted are generally new common shares but can be funded out of treasury shares, if available.

Total Stock-Based Compensation Expense

Stock-based compensation expense represents amortization of restricted stock and performance units. The following table details the amount of stock-based compensation that is allocated to functional expense categories for each of the years in the three-year period ended December 31, 2022 (in thousands):

	2022	2021	2020
Direct operating expense	$ 1,459	$ 1,310	$ 1,078
Brokered natural gas and marketing expense	2,439	1,794	1,416
Exploration expense	1,578	1,507	1,279
General and administrative expense	42,023	39,673	32,905
Exit costs	—	—	2,165
Total stock-based compensation	$ 47,499	$ 44,284	$ 38,843

Unlike the other forms of stock-based compensation expense mentioned above, the mark-to-market of the liability related to the vested restricted stock held in our deferred compensation plan is directly tied to the change in our stock price and not directly related to the functional expenses. Therefore, the liability related to the vested restricted stock held in our deferred compensation plans is not allocated to the functional categories and is reported as deferred compensation plan expense in the accompanying consolidated statements of operations.

In 2022, we recorded an additional tax benefit of an estimated $7.2 million for the tax effect of financial accounting expense compared to the corporate income tax deduction for equity compensation that vested during the year compared to additional tax benefit of $340,000 in 2021 and additional tax expense of $4.3 million in 2020.

Stock-Based Awards

Restricted Stock Awards. We grant restricted stock units under our equity-based stock compensation plans. These restricted stock units, which we refer to as restricted stock Equity Awards, generally vest over a three-year period and are contingent on the recipient's continued employment with us. These awards are net settled by withholding shares to satisfy income tax withholding payments due upon vesting. The remaining shares are remitted to individual brokerage accounts. The grant date fair value of the Equity Awards is based on the fair market value of our common stock on the date of grant. Shares to be delivered upon vesting are made available from authorized but unissued shares or shares held as treasury stock.

The compensation committee also grants restricted stock to certain employees and non-employee directors of the board of directors as part of their compensation. We also grant restricted stock to certain employees for retention purposes. Compensation expense is recognized over the balance of the vesting period, which is typically the end of three years for employee grants and one year after grant date vesting for non-employee directors. All restricted stock awards are issued at prevailing market prices at the time of the grant and the vesting is based upon an employee's continued employment with us. Prior to vesting, all restricted stock awards have the right to vote such stock (by the trustee) and receive dividends, if any, thereon. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, the majority of these shares are generally placed in our deferred compensation plan and, upon vesting, withdrawals are allowed in either cash or in stock. These Liability Awards are classified as a liability and are re-measured at fair value each reporting period. This mark-to-market amount is reported in deferred compensation plan expense in the accompanying consolidated statements of operations. Historically, we have used authorized but unissued shares of stock when restricted stock is granted. However, we also may utilize treasury shares when available.

Stock-Based Performance Units. We grant two types of performance share awards: one based on performance conditions measured against internal performance metrics and one based on market conditions measured based on Range's performance relative to a predetermined peer group ("TSR" awards).

Restricted Stock – Equity Awards

In 2022, we granted 1.4 million restricted stock Equity Awards to employees which generally vest over a three-year period compared to 2.3 million in 2021 and 4.5 million in 2020. We recorded compensation expense for these awards of $21.0 million in the year ended December 31, 2022 compared to $19.6 million in 2021 and $17.8 million in 2020. As of December 31, 2022, there was $23.3 million of unrecognized compensation related to Equity Awards expected to be recognized over a weighted average period of 1.7 years. Restricted stock Equity Awards are not issued to employees until such time as they are vested and the employees do not have the option to receive cash.

Restricted Stock – Liability Awards

In 2022, we granted 650,000 shares of restricted stock Liability Awards as compensation to non-employee directors and employees at an average grant date fair value of $20.94. These grants included 47,000 shares issued to non-employee directors, which vest at the end of one year and 603,000 shares to employees with vesting generally at the end of a three-year period. In 2021, we granted 1.3 million shares of restricted stock Liability Awards as compensation to directors and employees at an average grant date fair value of $9.56. This grant included 102,000 shares issued to non-employee directors, which vested at the end of one year and 1.2 million shares to employees with vesting generally at the end of a three-year period. In 2020, we granted 3.5 million shares of restricted stock Liability Awards as compensation to directors and employees at an average grant date fair value of $3.18. These grants included 217,000 shares issued to non-employee directors, which vested at the end of one year and 3.3 million shares to employees with vesting generally over a three-year period. We recorded compensation expense for these restricted stock Liability Awards of $13.6 million in the year ended December 31, 2022 compared to $11.4 million in 2021 and $10.3 million in 2020. As of December 31, 2022, there was $4.6 million of unrecognized compensation related to restricted stock Liability Awards expected to be recognized over a weighted average period of 1.1 years. A large portion of these awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market amount is reported as deferred compensation expense in our consolidated statements of operations (see additional discussion below). The proceeds received from the sale of stock held in our deferred compensation plan were $22.2 million in 2022 compared to $5.9 million in 2021 and $696,000 in 2020. The following is a summary of the status of our non-vested restricted stock outstanding at December 31, 2022:

	Restricted Stock Equity Awards		Restricted Stock Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2021	2,674,777	$ 7.39	796,629	$ 6.49
Granted	1,405,660	18.66	650,314	20.94
Vested	(2,283,837)	8.88	(1,067,310)	12.38
Forfeited	(59,912)	10.29	—	—
Outstanding at December 31, 2022	1,736,688	$ 14.44	379,633	$ 14.71

Stock-Based Performance Units

Internal Performance Metric Awards. These awards are earned, or not earned, based on performance metrics set by the compensation committee of our board of directors over a three-year performance period. The actual payout may be between 0% and 200% of the performance units granted and each unit represents the value of one share of our common share. Dividend equivalents, if any, accrue during the performance period and are paid in stock at the end of the performance period.

Internal performance metric awards granted in 2022 are earned based on:

- Net debt (total debt less cash balance); and
- GHG emissions intensity.

Internal performance metric awards granted in 2021 are earned based on:

- Debt/EBITDAX (earnings before interest, taxes, depreciation and amortization, and exploration expense); and
- GHG emissions intensity.

Internal performance metric awards granted in 2020 were earned based on:

- Debt and adjusted per share Production Growth; and
- Debt and adjusted per share Reserve Growth.

Prior to 2021, the performance period was based on annual performance targets earned over a three-year period. For awards granted in 2021 and 2022, the three-year target was set in the first quarter of the grant year. If the performance metric for the applicable period is not met, then that portion is considered forfeited and there is an adjustment to the expense recorded. The following is a summary of our non-vested internal performance metric awards activities at December 31, 2022:

	Number of Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2021	1,095,355	$ 7.80
Units granted [(a)]	153,089	20.38
Vested [(b)]	(243,482)	9.64
Forfeited	—	—
Outstanding at December 31, 2022	1,004,962	$ 9.27

[(a)] Amounts granted reflect the number of performance units granted; however, the actual payout of shares may be between zero and 200% depending on achievement of specifically identified performance targets.
[(b)] For awards granted in 2019, the aggregate payout was approximately 116% of target with a positive performance adjustment of 158,793 shares.

We recorded internal performance metric award compensation expense of $6.2 million in the year ended December 31, 2022 compared to $6.6 million in the year ended December 31, 2021 and $2.7 million in the year ended December 31, 2020. As of December 31, 2022, there was $1.8 million of unrecognized compensation related to these internal performance metric awards to be recognized over a weighted average period of 1.1 years.

TSR awards. These awards are earned, or not earned, based on the comparative performance of Range's common stock measured against a predetermined group of companies in the peer group over a three-year performance period. The actual payout of shares may be between zero and 200% of the performance units granted depending on the total stockholder return ranking compared to our peer companies on the vesting date. Their fair value is estimated on the date of grant using a Monte Carlo simulation model which utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The fair value is recognized as stock-based compensation expense over the three-year performance period. Expected volatilities utilized in the model were estimated using a combination of a historical period consistent with the remaining performance period of three years and option implied volatilities. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the life of the grant. The following assumptions were used to estimate the fair value of the TSR awards granted during the years ended December 31, 2022, 2021 and 2020:

	Year Ended December 31,		
	2022	2021	2020
Risk-free interest rate	1.4%	0.2%	1.4%
Expected annual volatility	68%	75%	65%
Grant date fair value per unit	$ 27.90	$ 12.58	$ 3.85

The following is a summary of our non-vested TSR award activities:

	Number of Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2021	1,147,994	$ 7.60
Granted [(a)]	111,828	27.90
Vested and issued [(b)]	(314,152)	11.34
Forfeited	—	—
Outstanding at December 31, 2022	945,670	$ 8.76

[(a)] These amounts reflect the number of performance units granted. The actual payout of shares may be between zero and 200% of the performance units granted depending on the total shareholder return ranking compared to our peer companies at the vesting date.
[(b)] Includes TSR awards issued related to the 2019 performance period where the return on our common stock was 127% and therefore, the performances multiple and actual payout was 183%.

We recorded TSR award compensation expense of $3.2 million in the year ended December 31, 2022 compared to $2.6 million in the year ended December 31, 2021 and $2.4 million in the year ended December 31, 2020. As of December 31, 2022, there was $1.5 million of unrecognized compensation related to these TSR awards to be recognized over a weighted average period of 1.3 years.

401(k) Plan

We maintain a 401(k) benefit plan that allows employees to contribute up to 75% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. We match up to 6% of salary in cash and vesting of those contributions is immediate. In 2022, we contributed $4.8 million to the 401(k) Plan compared to $4.6 million in 2021 and $5.3 million in 2020. Employees have a variety of investment options in the 401(k) benefit plan.

Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution which vests at the end of three years. The assets of the plans are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market loss of $61.9 million in 2022 compared to a loss of $68.4 million in 2021 and a loss of $12.5 million in 2020. The Rabbi Trust held 5.6 million shares (5.3 million of vested shares) of Range stock at December 31, 2022 compared to 6.2 million (5.4 million of vested shares) at December 31, 2021.

(12) Capital Stock

We have authorized capital stock of 485.0 million shares, which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2021:

	Year Ended December 31,	
	2022	2021
Beginning balance	249,792,908	246,348,092
Restricted stock grants	671,303	1,293,892
Restricted stock units vested	1,827,625	1,493,341
Performance stock units vested	590,940	640,468
Performance stock dividends	1,843	13,966
Treasury shares	(13,998,889)	3,149
Ending balance	238,885,730	249,792,908

Common Stock Dividends

In January 2020, we announced that the board of directors had suspended our common stock dividend. The quarterly cash dividend was reinstated by our board of directors in third quarter 2022. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the board of directors and will depend on our financial condition, earnings, capital requirements, levels of indebtedness, our future business prospects and other matters our board deems relevant. Our bank credit facility allows for the payment of common dividends, with certain limitations, as described in the facility agreement.

Stock Repurchase Program

In October 2019, the board of directors approved a stock purchase program to acquire up to $100 million of our outstanding stock. In early 2022, the board of directors approved an increase to this stock purchase plan where the board of directors authorized an additional repurchase of up to $430.0 million for an aggregate available amount at that time of $500.0 million. In October 2022, our board of directors authorized an additional repurchase of $1.0 billion for common stock repurchases. Under this program, we may repurchase shares of our common stock in open market transactions, from time to time, in accordance with applicable SEC rules and federal securities laws. In 2022, we repurchased 14.0 million shares at an aggregate value of $399.7 million. The following is a schedule of the change in treasury shares since the beginning of 2021:

	Year Ended December 31,	
	2022	2021
Beginning balance	10,002,646	10,005,795
Rabbi trust shares distributed and/or sold	(1,111)	(3,149)
Shares repurchased	14,000,000	—
Ending balance	24,001,535	10,002,646

(13) Supplemental Cash Flow Information

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Net cash provided from operating activities included:			
Income taxes paid to taxing authorities	$ (20,335)	$ (7,061)	$ (343)
Interest paid	(193,732)	(196,750)	(168,471)
Non-cash investing and financing activities included:			
Asset retirement costs capitalized, net	$ 18,096	$ 18,634	$ 2,610
Increase (decrease) in accrued capital expenditures	1,966	(4,505)	(23,625)

(14) Commitments and Contingencies

Litigation

We are the subject of, or party to, a number of pending or threatened legal actions and administrative proceedings or investigations arising in the ordinary course of our business including, but not limited to, royalty claims, contract claims and environmental claims. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations.

When deemed necessary, we establish reserves for certain legal proceedings. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible we could incur additional losses with respect to those matters in which reserves have been established. We will continue to evaluate our litigation on a quarterly basis and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

We have incurred and will continue to incur capital, operating and remediation expenditures as a result of environmental laws and regulations. As of December 31, 2022 and 2021, liabilities for remediation were not material. We are not aware of any environmental claims existing as of December 31, 2022 that have not been provided for or would otherwise have a material impact on our financial position or results of operations. Environmental liabilities normally involve estimates that are subject to revision until final resolution, settlement or remediation occurs. We believe that substantially all of our competitors must comply with similar environmental laws and regulations.

Obligations Following Divestitures

Certain contractual obligations were retained by us after our divestiture of our North Louisiana assets. These obligations are primarily related to gathering, processing and transportation agreements including certain minimum volume commitments. For additional information see Note 3, Note 10 and Note 15.

Lease Commitments

The components of our total lease expense for the two years ended December 31, 2022, the majority of which is included as part of natural gas and oil properties on our consolidated balance sheets, are as follows (in thousands):

	Year Ended December 31, 2022	Year Ended December 31, 2021
Operating lease cost	$ 37,873	$ 26,343
Variable lease expense (1)	22,082	27,243
Short-term lease expense (2)	1,807	1,950
Sublease income	(137)	(2,380)
Total lease expense	$ 61,625	$ 53,156
Short-term lease costs (3)	$ 17,285	$ 18,984

(1) Variable lease payments that are not dependent on an index or rate and are not included in the lease liability or ROU assets.

(2) Short-term lease expense represents expense related to leases with a contract term of one year or less and are not included in our ROU assets or lease liability in our consolidated balance sheets.

(3) These short-term lease costs are related to leases with a contract term of one year or less, the majority of which are related to drilling rigs which are capitalized as part of natural gas and oil properties on our consolidated balance sheets and may fluctuate based on the number of drilling rigs being utilized.

Supplemental cash flow information related to our operating leases is included in the table below (in thousands):

	Year Ended December 31, 2022	Year Ended December 31, 2021
Cash paid for amounts included in the measurement of lease liabilities	$ 37,457	$ 28,118
ROU assets added in exchange for lease obligations	$ 78,574	$ 1,059

Supplemental balance sheet information related to our operating leases is included in the table below (in thousands):

	Year Ended December 31, 2022	Year Ended December 31, 2021
Operating lease ROU assets	$ 84,070	$ 40,832
Accrued liabilities – current	$ (67,493)	$ (19,066)
Operating lease liabilities – long-term	$ (20,903)	$ (24,861)

Our weighted average remaining lease term and weighted average discount rate for our operating leases are as follows:

	Year Ended December 31, 2022	Year Ended December 31, 2021
Weighted average remaining lease term	2.0 years	3.8 years
Weighted average discount rate	6%	6%

Our lease liabilities with enforceable contract terms that are greater than one year mature as follows (in thousands):

	Operating Leases
2023	$ 70,873
2024	8,119
2025	6,576
2026	6,167
2027	2,626
Total lease payments	94,361
Less effects of discounting	(5,965)
Total lease liability	$ 88,396

Transportation, Gathering and Processing Contracts

We have entered into firm transportation and gathering contracts with various pipeline carriers for the future transportation and gathering of natural gas, NGLs and oil production from our properties in Pennsylvania. Under these contracts, we are obligated to transport or gather minimum daily natural gas volumes or pay for any deficiencies at a specified reservation fee rate. Our production committed to these pipelines is currently expected to exceed the minimum daily volumes provided in the contracts. However, if in the future we fail to deliver the committed volumes, we would recognize a deficiency payment in the period in which the under-delivery takes place and the related liability has been incurred. As of December 31, 2022, future minimum transportation and gathering fees under our commitments are as follows (in thousands):

	Transportation and Gathering Contracts [(a)]
2023	$ 801,850
2024	782,445
2025	694,670
2026	635,929
2027	582,580
Thereafter	2,971,614
	$ 6,469,088

(a) The amounts in this table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest which can vary based on volumes produced.

In addition to the amounts included in the above table, we have entered into an additional agreement which is contingent on certain pipeline modifications and/or construction for natural gas volumes of 1.8 bcf per day and is expected to begin in 2024 with a thirteen-year term. Volumes under this agreement decline in the last five years of the contract, ending at 810,000 mcf per day.

Not included in the table above is our estimate of accrued contractual obligations retained by us after our divestiture of our North Louisiana assets. These contractual obligations are related to gathering, processing and transportation agreements including certain minimum volume commitments. There are inherent uncertainties surrounding the retained obligation and, as a result, the determination of the accrued obligation required significant judgement and estimation. The actual settlement amount and timing may differ from our estimates. See also Note 3, Note 10 and Note 15 for more information. As of December 31, 2022, the carrying value of this obligation was $390.6 million and is included in divestiture contract obligation in our consolidated balance sheets. As of December 31, 2022, our estimated settlement of this retained obligation based on a discounted value is as follows (in thousands):

	Divestiture Contract Obligation
2023	$ 86,546
2024	73,916
2025	64,276
2026	45,773
2027	37,743
Thereafter	82,366
	$ 390,620

Delivery Commitments

We have various volume delivery commitments that are related to our Marcellus Shale properties. We expect to be able to fulfill our contractual obligations from our own production; however, we may purchase third-party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2022, our delivery commitments through 2037 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2023	365,000	50,000
2024	261,899	50,000
2025	182,493	50,000
2026	158,301	50,000
2027	100,000	46,233
2028	100,000	45,000
2029	100,000	33,444
2030	—	30,000
2031	—	16,575
2032-2037	—	10,000 (each year)

In addition to the amounts included in the above table, we have contracted with a pipeline company through 2037 to deliver ethane production volumes from our Marcellus Shale wells. These agreements and related fees, which are contingent upon facility construction and/or modification, are for 15,000 bbls per day starting in 2027 through 2033.

Other

We have lease acreage that is generally subject to expiration if initial wells are not drilled within a specified period, generally between three and five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

(15) Exit Costs

Exit Costs

In August 2020, we sold our North Louisiana assets and retained certain gathering, transportation and processing obligations which extend into 2030. These are contracts where we will not realize any future benefit. The estimated obligations are included in current and long-term divestiture contract obligation in our consolidated balance sheets. In the twelve months ended December 31, 2022, we recorded accretion expense of $43.6 million compared to $47.9 million in 2021 and $20.2 million in 2020. In second quarter 2022, we recorded a net unfavorable adjustment of $24.8 million to increase this obligation for a change in our forecasted drilling plans of the buyer along with adjusting the difference between estimated and actual payments. In second quarter 2021, we recorded a net favorable adjustment of $28.2 million to reduce this obligation due to a reduction of certain contractual payments compared to those originally estimated and a change to our assessment of drilling plans of the buyer. The present value of our estimated obligations related to these assets was initially recorded in 2020 as an exit cost at a total of $479.8 million. Also associated with this sale, we agreed to pay a midstream company $28.5 million to reduce our financial obligation related to the minimum volume commitments associated with this asset which was also recorded as an exit cost in third quarter 2020. The estimated discounted value for this divestiture contract obligation was $390.6 million at December 31, 2022.

In second quarter 2020, we negotiated capacity releases on certain transportation pipelines in Pennsylvania effective May 31, 2020 and extending through the remainder of the contract. As a result of these releases, we recorded exit costs of $10.4 million which represented the discounted present value of our remaining obligations to the third party. The remaining carrying value for these transportation capacity releases as of December 31, 2022 was $5.1 million.

Termination Costs

In third quarter 2020, we completed the sale of our North Louisiana assets and we recorded $2.5 million of severance costs and stock-based compensation expense. Also in third quarter 2020, we announced an additional reduction in our work force as we continued to focus on lowering administrative expenses and recorded $3.7 million of severance costs and stock-based compensation expense related to this reduction in force. In first quarter 2020, we completed the sale of our shallow legacy assets in Northwest Pennsylvania and we recorded $1.4 million of severance costs which is primarily related to the sale of these assets. The following summarizes our exit and termination costs for the three years ended December 31, 2022, 2021 and 2020 (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Severance costs	$ —	$ 567	$ 5,909
Transportation contract capacity releases (including accretion of discount)	579	754	10,900
Divestiture contract obligation (including accretion of discount)	69,758	20,340	499,935
One-time minimum volume commitment contract payment	—	—	28,500
Stock-based compensation and other	—	—	2,165
	$ 70,337	$ 21,661	$ 547,409

The following details the accrued exit and termination cost liability activity for the years ended December 31, 2022 and 2021 (in thousands):

	Exit Costs	Termination Costs
Balance at December 31, 2020	$ 493,543	$ 1,454
Accrued severance costs	—	567
Accrued contract obligations-changes in estimate	(27,575)	—
Accretion of discount	48,669	—
Payments	(90,895)	(2,011)
Balance at December 31, 2021	423,742	10
Accrued contract obligations-changes in estimate	26,183	—
Accretion of discount	44,154	—
Payments	(98,399)	(10)
Balance at December 31, 2022	$ 395,680	$ —

(16) Suspended Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. Capitalized exploratory well costs are presented in natural gas and oil properties in the accompanying consolidated balance sheets. If an exploratory well is determined to be impaired, the well costs are charged to exploration expense in the accompanying consolidated statements of operations. We had no capitalized exploratory well costs for year ended December 31, 2022. The following table reflects the changes in capitalized exploratory well costs for the years ended December 31, 2021 and December 31, 2020 (in thousands):

	2021	2020
Balance at beginning of period	$ 7,709	$ —
Additions to capitalized exploratory well costs pending the determination of proved reserves	6,329	7,709
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(14,038)	—
Capitalized exploratory well costs, charged to expense	—	—
Balance at end of period	$ —	$ 7,709
Less exploratory well costs that have been capitalized for a period of one year or less	$ —	$ (7,709)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ —	$ —

(17) Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)

Our natural gas and oil producing activities are conducted onshore within the continental United States and all of our proved reserves are located within the United States.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [(a)]

	December 31,		
	2022	2021	2020
		(in thousands)	
Natural gas and oil properties:			
Properties subject to depletion	$ 9,855,287	$ 9,338,236	$ 8,891,348
Unproved properties	800,592	837,334	859,766
Total	10,655,879	10,175,570	9,751,114
Accumulated depreciation, depletion and amortization	(4,765,475)	(4,420,914)	(4,064,305)
Net capitalized costs	$ 5,890,404	$ 5,754,656	$ 5,686,809

(a) Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development [(a)]

	December 31,		
	2022	2021	2020
		(in thousands)	
Acquisitions:			
Acreage purchases	$ 28,735	$ 21,942	$ 26,166
Development	460,668	381,753	369,093
Exploration:			
Drilling	—	6,329	7,709
Expense	25,194	22,048	31,376
Stock-based compensation expense	1,578	1,507	1,279
Gas gathering facilities:			
Development	1,466	3,402	3,694
Subtotal	517,641	436,981	439,317
Asset retirement obligations	18,096	18,634	2,610
Total costs incurred	$ 535,737	$ 455,615	$ 441,927

(a) Includes cost incurred whether capitalized or expensed.

Reserves Audit

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. At year-end 2022, Netherland, Sewell & Associates, Inc., an independent petroleum consultant, conducted an audit of our 2022 reserves in Appalachia. These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2022, our consultant audited approximately 96% of our proved reserves. A copy of the summary reserve report prepared by our independent petroleum consultant is included as an exhibit to this Annual Report on Form 10-K. The technical professional at our independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of data furnished during the reserves audit process. Throughout the year, our technical team meets periodically with representatives of our independent petroleum consultant to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, our senior management reviews and approves any significant changes to our proved reserves. We provide historical information to our consultant for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. The consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review identified reserve differences. The reserve auditor estimates of proved reserves and the pretax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared lease-by-lease, field-by-field or area-by-area, some of our estimates may be greater and some may be less than the estimates of our reserve auditor. When such differences do not exceed 10% in the aggregate, our reserve auditor is satisfied that the proved reserves and pretax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our independent petroleum consultants have been less than 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our President and Chief Executive Officer. Mr. Alan Farquharson, our Senior Vice President of Reservoir Engineering and Economics, holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources and has more than forty years of engineering experience in the oil and gas industry. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

Estimated Quantities of Proved Oil and Gas Reserves

Reserves of natural gas, NGLs, crude oil and condensate are estimated by our petroleum engineering staff and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, production taxes and other economic factors.

The SEC defines proved reserves as those volumes of natural gas, NGLs, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes 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 drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated when such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating each location is scheduled to be drilled within five years from the date it was booked as proved reserves, unless specific circumstances justify a longer time.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2022 to estimate reserve information were $87.14 per barrel of oil, $38.35 per barrel of NGLs and $6.08 per mcf for gas using a benchmark (NYMEX) of $94.13 per barrel and $6.36 per Mmbtu. The average realized prices used at December 31, 2021 to estimate reserve information were $59.35 per barrel of oil, $28.41 per barrel of NGLs and $3.30 per mcf for gas using a benchmark (NYMEX) of $66.34 per barrel and $3.60 per Mmbtu. The average realized prices used at December 31, 2020 to estimate reserve information were $30.13 per barrel of oil, $16.14 per barrel of NGLs and $1.68 per mcf for gas using a benchmark (NYMEX) of $39.77 per barrel and $1.98 per Mmbtu.

	Natural Gas (Mmcf)	NGLs (Mbbls)	Crude Oil and Condensate (Mbbls)	Natural Gas Equivalents (Mmcfe) [(a)]
Proved developed and undeveloped reserves:				
Balance, December 31, 2019	12,114,977	938,236	74,532	18,191,583
Revisions	(789,992)	42,741	(12,444)	(608,211)
Extensions, discoveries and additions	1,007,415	38,298	4,512	1,264,282
Property sales	(609,311)	(30,317)	(6,145)	(828,084)
Production	(574,529)	(37,492)	(2,829)	(816,456)
Balance, December 31, 2020	11,148,560	951,466	57,626	17,203,114
Revisions	(311,410)	16,845	(7,089)	(252,876)
Extensions, discoveries and additions	1,155,952	69,367	5,103	1,602,769
Production	(541,021)	(36,373)	(3,044)	(777,523)
Balance, December 31, 2021	11,452,081	1,001,305	52,596	17,775,484
Revisions	(393,165)	(20,251)	(12,885)	(591,983)
Extensions, discoveries and additions	1,278,499	59,296	5,661	1,668,244
Production	(539,443)	(36,392)	(2,716)	(774,089)
Balance, December 31, 2022	11,797,972	1,003,958	42,656	18,077,656
Proved developed reserves:				
December 31, 2020	6,350,057	550,771	22,976	9,792,540
December 31, 2021	6,809,849	577,506	23,833	10,417,887
December 31, 2022	7,230,313	594,931	22,213	10,933,180
Proved undeveloped reserves:				
December 31, 2020	4,798,503	400,695	34,650	7,410,574
December 31, 2021	4,642,232	423,798	28,762	7,357,597
December 31, 2022	4,567,659	409,027	20,443	7,144,476

(a) Oil and NGLs volumes are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

During 2022, we added approximately 1.7 Tcfe of proved reserves from drilling activities and evaluation of proved areas in the Marcellus Shale. Approximately 77% of the 2022 reserve additions are attributable to natural gas. Revisions of previous estimates of a negative 592.0 Bcfe include a positive revision of 716.2 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to our five-year development plan, positive performance revisions of 72.8 Bcfe and positive pricing revisions more than offset by 1.4 Tcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon. These wells were removed due to the outperformance of existing wells which resulted in a higher utilization of in-field gathering capacity and a reallocation of capital due to the drilling of longer laterals on existing locations.

During 2021, we added approximately 1.6 Tcfe of proved reserves from drilling activities and evaluation of proved areas in the Marcellus Shale. Approximately 72% of the 2021 reserve additions are attributable to natural gas. Revisions of previous estimates of a negative 252.9 Bcfe include positive performance revisions of 1.0 Tcfe and positive pricing revisions of 22.6 Bcfe more than offset by 1.3 Tcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon.

During 2020, we added approximately 1.3 Tcfe of proved reserves from drilling activities and evaluation of proved areas in the Marcellus Shale. Approximately 80% of the 2020 reserve additions are attributable to natural gas. Revisions of previous estimates of a negative 608.2 Bcfe include positive performance revisions of 420.9 Bcfe which were more than offset by 961.1 Bcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon and negative pricing revisions of 67.9 Bcfe.

The following details the changes in proved undeveloped reserves for 2022 (Mmcfe):

Beginning proved undeveloped reserves at December 31, 2021	7,357,597
Undeveloped reserves transferred to developed	(1,091,828)
Revisions [a]	(759,281)
Extension and discoveries	1,637,988
Ending proved undeveloped reserves at December 31, 2022	7,144,476

(a) Includes 1.4 Tcfe of proved undeveloped reserves removed and deferred due to the five-year rule which can be included in our future proved reserves as these locations are added back to our five-year development plan. Includes 716.2 Bcfe positive revision for previously proved undeveloped properties due to their addition back into our five year development plan.

During 2022, we spent approximately $430.0 million in development costs related to proved undeveloped reserves that were transferred to developed reserves. Estimated future development costs of proved undeveloped reserves are projected to be approximately $3.0 billion over the next five years. As of December 31, 2022, we have 87.8 Bcfe that have been reported for more than five years from their original date of booking, all of which are in the process of being completed and are expected to turn to sales in 2023. All of our recorded proved undeveloped drilling locations are scheduled to be drilled within five years of initial disclosure. All proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2027.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas, NGLs, crude oil and condensate reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas, NGLs and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas, NGLs, crude oil and condensate, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.
2. For the years ended 2022, 2021 and 2020, estimated future cash inflows are calculated by applying a twelve-month average price of natural gas, NGLs and oil relating to our proved reserves to the quantities of those reserves produced in each future year.
3. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas, NGLs and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.
4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas, NGLs and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas, NGLs, crude oil and condensate reserves is as follows and excludes cash flows associated with derivatives outstanding at each of the respective reporting dates. Future cash inflows are net of third-party transportation, gathering and compression expense.

	As of December 31,	
	2022	2021
	(in thousands)	
Future cash inflows	$ 113,954,835	$ 69,403,611
Future costs:		
Production	(31,991,109)	(27,015,321)
Development [(a)]	(3,313,724)	(2,469,028)
Future net cash flows before income taxes	78,650,002	39,919,262
Future income tax expense	(16,651,625)	(8,146,832)
Total future net cash flows before 10% discount	61,998,377	31,772,430
10% annual discount	(37,453,094)	(19,287,204)
Standardized measure of discounted future net cash flows	$ 24,545,283	$ 12,485,226

(a) 2022 includes $361.9 million of undiscounted future asset retirement costs as of December 31, 2022, using current estimates of future abandonment costs.

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	December 31,		
	2022	2021	2020
		(in thousands)	
Revisions of previous estimates:			
Changes in prices and production costs	$ 14,326,997	$ 11,600,850	$ (4,868,371)
Revisions in quantities	109,129	577,737	(345,073)
Changes in future development and abandonment costs	(524,847)	(53,818)	107,899
Net change in income taxes	(2,625,699)	(2,248,161)	797,816
Accretion of discount	1,486,783	298,077	756,083
Additions to proved reserves from extensions, discoveries and improved recovery	2,842,173	1,423,510	280,441
Natural gas, NGLs and oil sales, net of production costs	(3,550,632)	(1,934,254)	(402,450)
Actual development costs incurred during the period	471,877	399,681	384,530
Sales of reserves in place	—	—	(394,125)
Timing and other	(475,724)	(424,718)	(99,001)
Net change for the year	12,060,057	9,638,904	(3,782,251)
Beginning of year	12,485,226	2,846,322	6,628,573
End of year	$ 24,545,283	$ 12,485,226	$ 2,846,322

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal 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) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2022 at the reasonable assurance level.

Changes in Internal Controls over Financial Reporting. There have been no changes in our system of internal control over financial reporting during the three months ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting. See "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting" which appear on pages F-2 and F-3, respectively, under Item 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required in response to this item will be set forth in the Range Proxy Statement for the 2023 Annual Meeting of Stockholders to be held in May 2023 and is incorporated herein by reference.

See "Executive Officers of the Registrant" under Item 1 of this Form 10-K for the information about our executive officers.

Code of Ethics

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officer, principal financial officer, principal accounting officer, or persons performing similar functions (as well as our directors and all other employees). A copy is available on our website, www.rangeresources.com and a copy in print will be provided to any person without charge, upon request. Such requests should be directed to the Corporate Secretary, 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 or by calling (817) 870-2601. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our President and Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2023 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2023 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2023 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated herein by reference to the Range Proxy Statement for the 2023 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) **1. and 2**. Financial Statements and Financial Statement Schedules.

The financial statements and financial statement schedules listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K:

3. Exhibits.

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K.

Exhibit Number	Exhibit Description
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004) as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005) and the Certificate of Second Amendment to the Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 19, 2016)
4.1*	Description of Registrant's Securities
4.2	Form of 4.875% Senior Notes due 2025 (incorporated by reference to Exhibit A to Exhibit 4.1 on Form 8-K (File No. 001-12009) as filed with the SEC on May 14, 2015)
4.3	Indenture dated May 14, 2015 among Range Resources Corporation, as issuer, the Initial Guarantors (as defined therein) and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 14, 2015)
4.4	Second Supplemental Indenture, by and among Range Resources Corporation, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., dated as of August 23, 2016 (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K (File No. 001-12209) as filed with the SEC on August 25, 2016)
4.5	First Supplemental Indenture, by and among Range Resources Corporation, the guarantors named therein and U.S. Bank National Association, dated as of August 23, 2016 (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K (File No. 001-12209) as filed with the SEC on August 25, 2016)
4.6	Form of 8.25% Senior Notes due 2029 (incorporated by reference to Exhibit A to Exhibit 4.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 8, 2021)
4.7	Indenture dated January 8, 2021 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 8, 2021)
4.8	Form of 4.75% Senior Notes due 2030 (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 1, 2022)
4.9	Indenture dated February 1, 2022, among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank Trust Company National Association, as trustee (incorporated by reference to Exhibit 4.1 to our 8-K (file No. 001-12209) as filed with the SEC on February 1, 2022)
10.01	Seventh Amended and Restated Credit Agreement, dated April 14, 2022, among Range Resources Corporation, as borrower, JPMorgan Chase Bank, N.A., as Administrative Agent and Letter of Credit Issuer or Lender from time-to-time party thereto (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on April 18, 2022)
10.02*	Amended and Restated Range Resources Corporation 2004 Deferred Compensation Plan for Directors and Select Employees effective January 31, 2023
10.03	Range Resources Corporation Amended and Restated 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on June 4, 2009)

10.04	First Amendment to the Range Resources Corporation Amended and Restated 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010)
10.05	Second Amendment to the Range Resources Corporation Amended and Restated 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 19, 2011)
10.06	Range Resources Corporation Amended and Restated 2019 Equity – Based Compensation Plan (incorporated by reference to Exhibit A to our Definitive Proxy Statement (File No. 001-12209) as filed with the SEC on April 1, 2022
10.07	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.08	Amended and Restated Range Resources Corporation Executive Change in Control Severance Benefit Plan effective December 31, 2008 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)
10.09	Supplement No. 1 to the Amended and Restated Executive Change in Control Severance Benefit Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 12, 2020)
10.10	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.6 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 17, 2009)
10.11	Purchase Agreement, dated January 13, 2022, by and among Range Resources Corporation, Range Production Company, LLC, Range Resources-Appalachia, LLC, Range Resources-Louisiana, Inc. Range Resources – Midcontinent, LLC, Range Resources – Pine Mountain, Inc. and Wells Fargo Securities, LLC, as a representative of the Initial Purchasers (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 14, 2022)
21*	Subsidiaries of Registrant
22*	Subsidiary Guarantors
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent of Netherland, Sewell & Associates, Inc., independent consulting engineers
31.1*	Certification by the Chairman and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the Chairman and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc., independent consulting engineers
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)

* Filed herewith.

** Furnished herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

RANGE RESOURCES CORPORATION

By: /s/ JEFFREY L. VENTURA

Jeffrey L. Ventura
Chief Executive Officer and President
(principal executive officer)

Dated: February 27, 2023

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Capacity	Date
/s/ JEFFREY L. VENTURA **Jeffrey L. Ventura**	Chief Executive Officer and President (principal executive officer)	February 27, 2023
/s/ MARK S. SCUCCHI **Mark S. Scucchi**	Executive Vice President and Chief Financial Officer (principal financial officer)	February 27, 2023
/s/ DORI A. GINN **Dori A. Ginn**	Senior Vice President, Controller and Principal Accounting Officer (principal accounting officer)	February 27, 2023
/s/ GREG G. MAXWELL **Greg G. Maxwell**	Chairman of the Board	February 27, 2023
/s/ BRENDA A. CLINE **Brenda A. Cline**	Director	February 27, 2023
/s/ MARGARET K. DORMAN **Margaret K. Dorman**	Director	February 27, 2023
/s/ JAMES M. FUNK **James M. Funk**	Director	February 27, 2023
/s/ STEVEN D. GRAY **Steven D. Gray**	Director	February 27, 2023
/s/ REGINAL W. SPILLER **Reginal W. Spiller**	Director	February 27, 2023

RANGE RESOURCES®