2021
ANNUAL REPORT

RANGE RESOURCES®

FELLOW SHAREHOLDERS

In 2021, Range continued its transformational progress toward corporate objectives through capital-efficient operations and disciplined spending, as we reduced financial leverage with record free cash flow. Our stated mission has been to realize the value of Range's world-class asset, paired with a world-class balance sheet, and consistently deliver shareholder returns over our multi-decade core inventory life. We believe Range is in the best position in the Company's history. Following the success of 2021 and the current multi-year outlook, Range has initiated additional returns of capital to shareholders that we expect to maintain and build upon in the coming years.

Range safely and efficiently delivered on our 2021 production plan, producing 2,130 Mmcfe per day during the year by investing $414 million in capital, or $11 million less than originally budgeted. 2021 marked the fourth consecutive year Range successfully executed operational plans with capital spending under budget, which reflects the team's commitment to disciplined capital spending and achieving cost leadership. **As a result of the outstanding work from the Range team, we continue to be the most efficient natural gas producer in the country, as measured by total well costs per lateral foot and maintenance capital requirements per unit of production.** We believe the latter of these metrics is the most useful and easily compared across commodity producers. Range's 2021 results show total capital spending of $0.53 per mcfe, which was the lowest among natural gas producers, and Range expects to deliver the most capital-efficient program among natural gas peers once again in 2022. One of our distinct advantages has been a production base decline of less than 20%, requiring less production to be replaced each year compared to peers. A competitive base decline rate comes from having over a decade of Marcellus production, as well as thoughtful planning of both gathering and compression infrastructure. This translates to a low capital intensity that is unmatched amongst E&P companies, providing Range a solid foundation for generating significant free cash flow and returns to shareholders.

We continue to realize the environmental benefits of Range's consolidated acreage position. In 2021, we further optimized our sourcing and transporting of water, which resulted in increased efficiencies. New records were set for water trucked to location, total reuse water utilized, and the percentage of reuse water used in each completion stage. Range's utilization of third-party water increased by 15% in 2021 versus 2020, with recycled water accounting for over 60% of all water utilized in our operations. The savings associated with our water sharing program, which allows us to recycle water from nearby operators, exceeded $13 million while recycling approximately 150% of Range's produced water volume and significantly reducing the use of freshwater sources. The use of both an electric frac fleet and a dual fuel fleet continued to limit diesel consumption, as clean burning natural gas remained the main source of fuel for our completion operations. In total, we substituted over 4 million gallons of diesel fuel with a net cost savings of $7.8 million. As highlighted in last year's shareholder letter, a contiguous acreage position allows Range to take full advantage of this technology and continue utilizing this type of equipment for our go-forward operations.

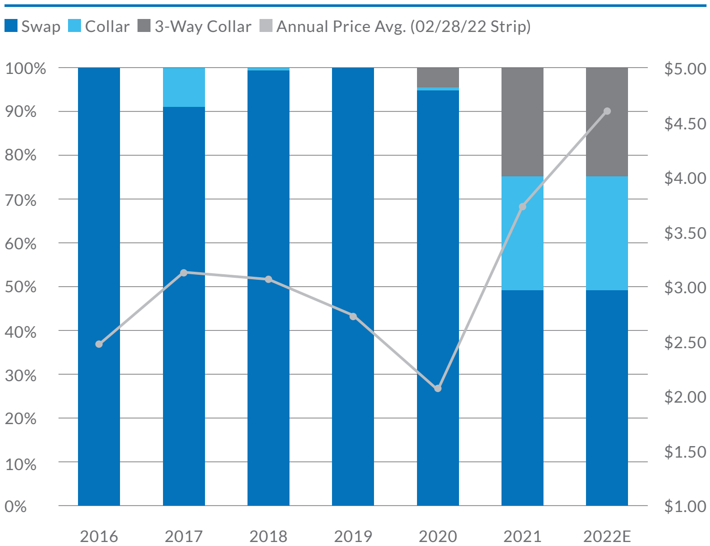
During the year, Range announced a combination of our marketing, operational, and ESG efforts by selling responsibly sourced gas (RSG) from Range's assets. We continue to explore various third-party certification options to ensure our future steps align with our external stakeholders, our commercial partners, and our company culture. The RSG market is continuing to evolve, and we believe Range's assets and multi-year ESG enhancements position us well

to capitalize on this growing demand. We continue to make meaningful progress towards our emissions reduction targets of net zero emissions for scope 1 and scope 2 by 2025. Since 2017, we've achieved a 69% reduction in greenhouse gas emissions intensity, which includes an 86% reduction in methane emissions intensity. In addition, our reported equipment emissions were reduced thanks to an increased frequency of leak detection inspections, commonly referred to as LDAR surveys, which locate and allow us to promptly address emissions in the field. In addition to emission reductions, these efforts have also improved the efficiency and safety of our production facilities.

Range benefited from the steady improvements in commodity prices throughout the year. Range's record free cash flow in 2021 not only speaks to improved commodity prices, but also the hedging decisions Range made through 2020 and early 2021 that allowed us to capture a significant portion of the improved prices for our production. Range finished the year with record free cash flow of approximately $656 million, led by a strong fourth quarter that included our highest quarterly pre-hedge price realizations since 2014.

Hedging results and strategy have understandably been a focus for the industry, as we all assess near-term opportunity cost while also shifting future strategies to retain participation in projected improved prices. Range made the decision in 2020 to pivot toward collar structures for the 2021 and 2022 natural gas hedge book relative to what were historically swap-heavy programs. Near-term, the strategy of reducing risk through hedging remains part of our plan but will evolve over time with Range's strengthening financial profile

NATURAL GAS HEDGING STRUCTURE–2016 TO PRESENT



and changing market supply and demand dynamics. When prices are attractive such that Range can protect returns that exceed most other industries, we may elect to hedge a portion of production to support the commitments of free cash flow, balance sheet improvement, and prudent returns of capital to shareholders. In 2022, we seek to deliver top tier returns on capital employed, to generate free cash flow directed to absolute debt reduction and shareholder returns, and to be balanced in risk management to retain the benefit of improved industry fundamentals.

With the significant debt reduction progress made to date, strong expected cash flow in 2022 and 2023, and a supportive hedge book that mitigates price risk while retaining attractive exposure to higher commodity prices, Range expects to reinstate its quarterly dividend in mid-2022 at $0.08 per share, or $0.32 annually. Our planned dividend is a two-fold message to stakeholders: first, it is a commitment to durable, tangible shareholder returns from business earnings, and second, it is a commitment to maintain a balance sheet that can sustain shareholder returns through commodity price cycles. Of perhaps greater importance is the approval for an expanded share repurchase program, now with aggregate capacity of $500 million. We believe this is a powerful tool to take advantage of what we see as an attractive investment opportunity, given the significant variance between the value of Range's inventory and production versus equity share price. For example, with year-end PV10 (using strip pricing) of $12.7 billion, which equates to roughly $40 per share net of debt, we believe share repurchases are a compelling investment. Notably, this comparison is to a PV10 value that ignores the significant value

of decades of quality inventory beyond the five-year development window included in SEC proved reserves. Our commitment is to remain flexible and adapt to market conditions, project returns, and prudent reinvestment with the repurchase program. We believe this provides a compelling option for use of free cash flow.

Shareholder value creation through the generation of free cash flow, and its prudent re-deployment, is our primary focus. Our capital budget for 2022 is $460 to $480 million. We expect this program to maintain production in the range of 2.12 to 2.16 Bcf equivalent per day, and to materially reduce outstanding debt and lower our leverage ratio throughout the year, based on recent commodity pricing. We believe that an appropriate debt level for the Company is between $1.0 and $1.5 billion, which is an achievable target at current strip pricing over the coming quarters. This range of debt is consistent with the balance sheet targets described in last year's proxy and provides a financial foundation which will enable Range to be both resilient and opportunistic through commodity price cycles. We agree with the strategic approach that appears to have taken root in the energy sector: one of prioritizing safe operations and shareholder returns, and emphasizing sustainable performance. Our Board, management team, and employees understand that sustainability is about creating long-term value, which includes a commitment to environmental stewardship, positively contributing to the communities where we operate, and underpinned by strong corporate governance. Strong governance creates accountability, encourages transparency, guides strategic focus, and aligns interests with stakeholders.

As the world continues to move towards cleaner, more-efficient fuels, we are firmly convinced that natural gas and NGLs will be the affordable, reliable, and abundant supply that helps to power our everyday lives and provide feedstock for essential products that we all use. These resources will help billions of people improve their standard of living and reduce their reliance on coal, biomass, and other more carbon-intensive fuels. We believe Appalachia natural gas and natural gas liquids are well positioned to meet that current and future demand. Within Appalachia, Range will be among those leading the charge on emissions intensity, capital efficiency, and transparency, which are all core to generating sustainable long-term value for shareholders.

We want to acknowledge our great employees. Our commitment to safety, environmental protection, and efficient operations starts with the individuals we have on the Range team. Through pandemic-related challenges, our employees found creative ways to support and stay connected with the community both in-person and virtually. For example, Range hosted the second annual 2000 Turkeys Telethon in 2021. The telethon was successful in raising money for the Greater Pittsburgh Community Food Bank, which went directly to help feed families in Washington County during the holiday season. The hour-long live telethon featured music, cooking demonstrations, and interviews with elected officials, community leaders, and business owners, all while our employee volunteers worked the phone bank collecting donations and pledges. This event, while virtual, provided a unique opportunity to bring the community together to support each other.

Range's community partnerships also go beyond financial support. Over the years, we have taken a vested interest in hearing from our partners, and we know that lending a helping hand makes a significant difference to them. During the spring, employee volunteers partnered with six Washington County townships to focus on environmental improvement opportunities. These beautification and revitalization projects served to celebrate Earth Day with the communities at the core of our operating footprint. Our team's efforts span year-long projects, including planting 1,200 tree saplings near a producing well site, stream cleanups, and local park beautifications.

In closing, we will repeat our belief that **Range is in the best position in the Company's history**. The well-defined and achievable objective all of us at Range work toward daily is to sustain a business that will be resilient through cycles, return capital to shareholders, and responsibly create compelling value. We want to thank our fellow Directors for their guidance and commitment to long-term value creation for shareholders. Most importantly, we thank you, our shareholders, for your continued support.

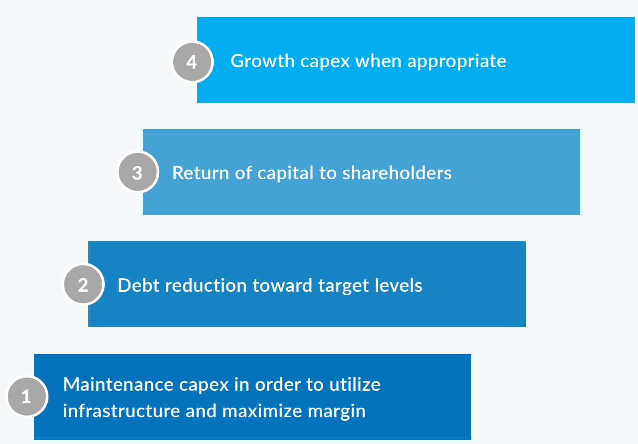
GREG G. MAXWELL
CHAIRMAN

JEFFREY L. VENTURA
CHIEF EXECUTIVE OFFICER
& PRESIDENT

RANGE'S RETURN OF CAPITAL

A return of capital framework is not a standalone commitment, it is an integral part of our capital allocation strategy. We have described our "waterfall" for use of cash flow:

1. Maintenance capex in order to utilize infrastructure and maximize margin
2. Debt reduction toward target levels
3. Return of capital to shareholders
4. Growth capex when appropriate



It is important to note that this hierarchy entails flexibility to allocate based on highest overall returns to the company and its shareholders. With Range's leading full-cycle costs, margins are strong, generating significant free cash flow that can be used to further strengthen the balance sheet while returning capital to shareholders.

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*

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

SENIOR MANAGEMENT

JEFFREY L. VENTURA	*Chief Executive Officer & President*
MARK S. SCUCCHI	*Senior Vice President – Chief Financial Officer*
DENNIS L. DEGNER	*Senior Vice President – Chief Operating Officer*
ALAN W. FARQUHARSON	*Senior Vice President – Reservoir Engineering & Economics*
DORI A. GINN	*Senior Vice President – Controller & Principal Accounting Officer*
DAVID P. POOLE	*Senior Vice President – General Counsel & Corporate Secretary*
K. SCOTT ROY	*Senior Vice President*

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, 2021, 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, 2021

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. ☒

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, 2021 was $4,229,441,000. 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 18, 2022, there were 262,145,991 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 2022 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 2022 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 our key operating market;
- prices and availability of goods and services, including third-party infrastructure;
- unforeseen hazards such as weather conditions, health pandemics, acts of war or terrorist acts;
- electronic, cyber or physical security breaches;
- changes in safety, health, environmental, tax and other regulations or requirements or initiatives including those addressing the impact of global climate change, air emissions 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 operation 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 areas of operation. 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, 2021, we had 259.8 million shares outstanding. At year-end 2021, our proved reserves had the following characteristics:

- 17.8 Tcfe of proved reserves;
- 64% natural gas, 34% NGLs and 2% crude oil and condensate;
- 59% proved developed;
- nearly 100% operated;
- a reserve life index of approximately 22 years (based on fourth quarter 2021 production);
- a pretax present value of $14.9 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 $12.5 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 $2.4 billion at December 31, 2021. PV-10 for December 31, 2021 was determined using NYMEX benchmark prices of $3.60 per mcf for natural gas and $66.34 per bbl for oil.

Our estimated proved reserves increased 3% to 17.8 Tcfe at December 31, 2021 from 17.2 Tcfe at December 31, 2020. Reserve additions from extensions and discoveries were the result of a successful development program and completion optimizations that resulted in improved well performance. The 2021 reserve additions and higher prices were partially offset by 2021 production volumes of 777.5 Bcfe and 1.3 Tcfe of reserves reclassified to unproved because of previously planned wells not expected to be drilled within the original five-year development horizon. We believe these unproved reserves can be included in our future proved reserves as these locations are added back into our five-year development plan.

Highlights of our 2021 production were:

- total production of 541.0 Bcf of natural gas, 36.4 Mmbbls of NGLs and 3.0 Mmbbls of crude oil and condensate;
- average daily production of 2.13 Bcfe per day, a decrease of 5% from 2020 which reflects the impact of the divestiture of our North Louisiana properties in August 2020; and
- excluding our North Louisiana properties from production in 2020, total production was approximately the same as the previous year.

Executive Summary for 2021

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 2019, natural gas prices have been as low as $1.50 per Mmbtu and as high as $6.20 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. We have focused on areas that are within our control. Currently, our focus is on enhancing cash flow through cost reductions and operational efficiencies, while strengthening our balance sheet, rather than expansion and growth. We prioritize free cash flow generation across a broad range of commodity products. To the extent commodity prices decline, we would intend to limit capital spending to at or below cash flow. During 2021, we:

- issued $600.0 million aggregate principal amount of new 8.25% senior notes due 2029;
- decreased total debt $165.3 million and increased cash on hand $214.0 million;
- maintained our bank committed borrowing capacity at $2.4 billion;
- spent approximately $10.6 million less than our initial 2021 capital budget of $425.0 million;
- recognized an average realized price (excluding derivative settlements and third party transportation costs) increase of 110% from 2020;
- recognized an average realized price (including derivative settlements and third party transportation costs) increase of 86% from 2020;
- reduced direct operating expense by $16.9 million, a reduction of 18% from 2020 reflecting the divestiture of higher operating cost properties;
- reduced our depletion, depreciation and amortization rate per mcfe 2% from 2020;
- increased our estimates of proved reserves at December 31, 2021 to 17.8 Tcfe from 17.2 Tcfe at December 31, 2020 which includes 1.6 Tcfe of drilling additions;
- held our drilling and completion costs to at or below $600 per foot;
- published our second formal corporate sustainability report which discusses our continued focus and commitment to the environment and the communities where we work and expanded our strategic goal of net zero greenhouse gases ("GHG") emissions by year-end 2025 to include both Scope 1 and Scope 2;
- committed to a pilot certification program for responsibly sourced natural gas;
- continued with our innovative water recycling program;
- continued utilizing an electric hydraulic fracturing fleet; and
- achieved a 40% reduction in employee recordable incident rates compared to 2020.

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 flow from reserves and production through internally generated drilling projects coupled with occasional acquisitions and divestitures of non-core, or at times, core assets. In addition, we target funding our capital spending to at or below operating cash flow. 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:

- commitment 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 one region: 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 3,400 proven and unproven 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 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 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. We regularly review our asset base to identify nonstrategic assets, the disposition of which is expected to increase capital resources available for other activities and create organizational and operational efficiencies.

Provide Employee Equity Ownership and Incentive Compensation Aligned with Our Stakeholders' Interest. 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, 2021, our employees and directors owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $263.0 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 2021

- ***Proved reserves*** – Total proved reserves increased 3% in 2021 compared to 2020, from 17.2 Tcfe to 17.8 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 2021, our production averaged 2.13 Bcfe per day, a decrease of 5% from 2020 reflecting the impact of the sale of our North Louisiana properties. Excluding production from these North Louisiana properties in 2020, our production was approximately the same when compared to 2020. 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, 2021, we maintained a $4.0 billion bank credit facility, with a borrowing base of $3.0 billion and committed borrowing capacity of $2.4 billion. We endeavor to maintain a strong liquidity position. In 2021, we reduced our aggregate principal amount of debt by $165.3 million. We ended 2021 with strong liquidity resulting from $214.4 million of cash and $2.1 billion available under the credit facility. Also, in early January 2022, we issued $500.0 million of new 4.75% senior notes due 2030; with the proceeds from this issuance, cash on hand and borrowings under our credit facility, we redeemed our 9.25% senior notes due 2026 in February 2022. Our 2021 capital budget, which was established at the beginning of the year, was originally $425.0 million with actual spending for 2021 approximately $10.6 million lower. 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 2021, we drilled 59 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. In 2021, we continued to reduce average well costs per foot drilled through faster drilling times, longer laterals and innovative completion optimizations.

- ***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, now expanded to include Scope 1 and Scope 2 emissions. During the year, we committed to a pilot program seeking to certify our natural gas as responsibly sourced. We continued to recycle approximately 100% of produced water and our non-fresh water spill rate was reduced 48% when compared to 2020. We also saw a 29% reduction in our notices of violations.

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 2022

For 2022, we expect our capital budget to be in the range of $460.0 million to $480.0 million for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. This budget includes $425.0 million to $445.0 million for drilling costs and $35.0 million for acreage and other expenditures and is expected to achieve 2022 production similar to 2021 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 2022 is for our capital expenditure program to be funded within operating cash flows. However, in the event our 2022 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 2022 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;
- target limiting capital spending at or below cash flow;
- reduce direct emissions and target net-zero Scope 1 and Scope 2 GHG emissions by year-end 2025;
- achieve competitive returns on investments;
- preserve liquidity and improve financial strength;
- focus on organic opportunities through disciplined capital investments;
- improve operational efficiencies and economic returns;
- 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 2021, 2020 and 2019 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)]	%
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%
2019:					
Proved					
Developed	6,486,211	535,007	34,369	9,902,468	54%
Undeveloped	5,628,766	403,229	40,163	8,289,115	46%
Total Proved	12,114,977	938,236	74,532	18,191,583	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 2021 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 2021, 2020 and 2019, in the aggregate, represented 97%, 97% and 90% of our proved reserves. The reserve audits performed for 2021, 2020 and 2019, in the aggregate represented 97%, 99% and 94% of our 2021, 2020 and 2019 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, 2021, 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, 2021, NGLs represented approximately 34% 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 2021 averaged approximately 52% 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, 2021, our PUDs totaled 28.8 Mmbbls of crude oil, 423.8 Mmbbls of NGLs and 4.6 Tcf of natural gas, for a total of 7.4 Tcfe. Costs incurred in 2021 relating to the development of PUDs were approximately $361.3 million. All PUD drilling locations are scheduled to be drilled prior to the end of 2026. As of December 31, 2021, we have 21 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 2022. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 1.2 Tcfe of PUDs into proved developed reserves;
- addition of 1.5 Tcfe new PUDs from drilling; and
- 393.6 Bcfe net negative revision with 1.3 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 performance revisions of 929.4 Bcfe.

For an additional description of changes in PUDs for 2021, 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):

	2021	2020	2019	2018	2017
Future net cash flows	$ 39,919	$ 9,795	$ 22,179	$ 34,836	$ 21,469
Present value:					
Before income tax	14,868	2,981	7,561	13,173	8,147
After income tax (Standardized Measure)	12,485	2,846	6,629	11,116	7,165
Benchmark prices (NYMEX):					
Gas price (per mcf)	3.60	1.98	2.58	3.10	2.98
Oil price (per bbl)	66.34	39.77	55.73	65.55	51.19
Wellhead prices:					
Gas price (per mcf)	3.30	1.68	2.38	2.98	2.60
Oil price (per bbl)	59.35	30.13	49.24	59.96	45.73
NGLs price (per bbl)	28.41	16.14	17.32	25.22	17.84

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 and Upper Devonian formations. We own 1,350 net producing wells, almost all of which we operate. Our average working interest in this region is 94%. As of December 31, 2021 we have approximately 909,000 gross (794,000 net) acres under lease. During 2021, we had approximately three drilling rigs in the field and expect to run an average of three drilling rigs throughout 2022.

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 2019 and 2020, was the only field in which our reserves were greater than 15% of our total proved reserves. For the year ended December 31, 2021, substantially all of our reserves are located in the Marcellus Shale.

	Marcellus Shale		
	2021	2020	2019
Production:			
Natural gas (Mmcf)	540,824	544,079	516,031
NGLs (Mbbls)	36,365	36,185	36,013
Crude oil and condensate (Mbbls)	3,032	2,599	3,199
Total Mmcfe [(a)]	777,205	776,786	751,299
Sales Prices: [(b)]			
Natural gas (per mcf)	$ 2.29	$ 0.49	$ 1.13
NGLs (per bbl)	17.12	4.91	7.12
Crude oil and condensate (per bbl)	59.76	29.24	49.73
Total (per mcfe) [(a)]	2.62	0.67	1.33
Production Costs:			
Lease operating (per mcfe)	$ 0.10	$ 0.10	$ 0.11
Production and ad valorem tax (per mcfe) [(c)]	0.04	0.02	0.03

(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, 2021 were 17.8 Tcfe, an increase of 572.4 Bcfe, or 3%, from 2020. Drilling additions of 1.6 Tcfe, favorable pricing revisions of 22.6 Bcfe and positive performance revisions of 1.0 Tcfe were partially offset by production of 777.2 Bcfe and downward revisions for proved undeveloped reserves deferred beyond our current five-year development plan of 1.3 Tcfe. Annual production was the same as production in 2020. During 2021, we spent $388.1 million in this region to drill 58 (57.1 net) development wells and 1 (1.0 net) exploratory well, all of which were productive. At December 31, 2021, we had an inventory of over 3,400 proven and unproven drilling locations. During the year, we drilled 59 proven locations in the Appalachian region, added 140 new proven drilling locations and deleted 82 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.

Divestitures

Over the last three years, we have divested over $1.0 billion of assets in order to increase capital resources available for other activities, reduce our unit cost structure, create organizational and operating efficiencies and increase financial flexibility. See Note 3 to our consolidated financial statements for more detail on our divestitures.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2021. 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 Interest
	Gross	Net	
Natural gas	1,430	1,349	94%
Crude oil	3	1	34%
Total	1,433	1,350	94%

Production 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, 2021, we had 33 gross (33 net) wells in the process of drilling or active completions stage. In addition, there were 22 gross (21 net) wells waiting on completion or waiting on pipelines at year-end 2021.

	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	58.0	57.1	52.0	51.4	94.0	92.6
Dry	—	—	—	—	—	—
Exploratory wells						
Productive	1.0	1.0	—	—	—	—
Dry	—	—	—	—	—	—
Total wells						
Productive	59.0	58.1	52.0	51.4	94.0	92.6
Dry	—	—	—	—	—	—
Total	59.0	58.1	52.0	51.4	94.0	92.6
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, 2021. 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	798,904	705,585	74,163	69,323	873,067	774,908
Texas	6,242	4,323	—	—	6,242	4,323
West Virginia	5,876	5,197	—	—	5,876	5,197
	833,000	724,545	76,428	69,890	909,428	794,435
Average working interest		87%		91%		87%

Undeveloped Acreage Expirations

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

As of December 31,	Acres Gross	Acres Net	% of Total Undeveloped
2022	14,440	13,733	20%
2023	19,098	18,162	26%
2024	12,691	11,696	17%
2025	10,880	9,174	13%
2026	16,447	15,956	23%

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, 2022, we had 527 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 5.5% over the five-year period ending December 31, 2021.

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 eight OSHA recordable incidents in 4.1 million work hours over the three-year period from 2019 through 2021, for an average Total Recordable Incident Rate of 0.4 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, 2022, are as follows:

	Age	Position
Jeffrey L. Ventura	64	Chief Executive Officer and President
Mark S. Scucchi	44	Senior Vice President – Chief Financial Officer
Dennis L. Degner	49	Senior Vice President – Chief Operating Officer
Dori A. Ginn	64	Senior Vice President – Controller and Principal Accounting Officer
David P. Poole	59	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, senior 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, senior 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 received 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 June 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 received 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. 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. 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. 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 if ongoing 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, 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;
- operation of underground injection wells to dispose of produced water and other liquids;
- the 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 13, 2022, FERC issued a final rule increasing the maximum civil penalty for violations of the NGA from $1,307,164 per day per violation to $1,388,496 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 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance 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, 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 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 FERC currently regulates rates of interstate liquids pipelines, primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning in July 2021, the FERC has established an annual index adjustment equal to the producer price index for finished goods plus 0.78%. This adjustment is subject to review every five years. 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 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.

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). 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. 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, including compressor stations. 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. The public comment period for this proposed rule ran through January 31, 2022, although the EPA has already stated that it intends to issue a supplemental proposal in 2022 that will provide proposed regulatory text and may expand on or modify this 2021 proposal in response to public input. 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. According to an update on December 9, 2021, this proposed rule could be promulgated and submitted to the EPA in the second quarter of 2022. Since this proposed rulemaking is not final, the impact on us is uncertain at this time. 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 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 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 2021, nor do we anticipate that such expenditures will be material in 2022. However, we regularly incur expenditures to comply with environmental laws and 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 company's 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 64% of our proved reserves were natural gas as of December 31, 2021 and at times, 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 fuels;
- the effect of worldwide energy conservation efforts;
- the ability of the members of OPEC and other exporting nations that work together to agree and 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.

Our indebtedness could limit our ability to successfully operate our business. Our exploration and development program will require substantial capital resources depending on the level of drilling and the expected cost of services. Existing operations require ongoing capital expenditures and the amount of our debt could limit our financial flexibility and ability to fund our operations. The degree to which we are indebted could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- at times, a portion of our borrowings is at variable rates of interest, making us vulnerable to increases in interest rates;

- our leverage may make us more vulnerable to a downturn in commodity prices or the general economy;
- we are subject to numerous financial and other restrictive covenants contained in our existing debt agreements that restrict our ability to engage in certain activities and that could limit our growth, and the breach of such covenants could materially and adversely impact our ability to continue as a going concern; and
- our debt level could limit our flexibility to maintain or grow the business and plan for, or react to, changes in our business and the industry in which we operate.

The risks described above may further increase in the event we incur additional debt. In addition to those risks above, we may not be able to obtain funding on acceptable terms.

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 were 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. In addition, our cash flow and capital resources may be insufficient for payment of interest on, and principal of, our debt in the future and any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms and it would result in the acceleration of the obligation to repay the indebtedness in full at a time when it would be unlikely we would have the ability to do so.

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. 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 2021, both 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 may be unable to dispose of nonstrategic assets on attractive terms and may be required to retain liabilities for certain matters. We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. We also occasionally sell interests in certain core assets for the purpose of accelerating development and increasing efficiencies in other core assets. Various factors could materially affect our ability to dispose of nonstrategic assets or complete announced dispositions, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to us and the fact that as a result of previous such asset sales, we have few remaining nonstrategic assets which we could sell. Also, sellers in such transactions typically retain liabilities for certain matters. For example, related to the sale of our North Louisiana assets, we retained certain midstream gathering, transportation and processing obligations through 2030. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, third parties are often unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

We could experience periods of higher costs. These cost increases could reduce our profitability, cash flow and ability to conduct development activities as planned. 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.

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;
- natural disasters;
- surface craterings and explosions;
- 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 two third-party processing plants and connecting lines 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 plant; 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. With the divestiture of our North Louisiana assets in third quarter 2020, 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. As a result of this significant concentration, we are particularly exposed to the impacts of regional supply and demand factors for a portion of our products. 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 pipeline systems and processing facilities 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, taking into consideration 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 and 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 in 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, under environmental laws and regulation, and we are currently and have in the past been involved in such investigations, remediation and monitoring activities. For example, in 2020, the Pennsylvania Attorney General filed misdemeanor criminal charges against us for certain releases and spills that we had reported and remediated under the direction of the DEP. While we have resolved these charges, the Pennsylvania Attorney General has publicly announced additional 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. While the revision to the definition of "waters of the United States" in the EPA's final rule on June 22, 2020 narrowed the scope of the CWA, the EPA, in response to a January 2021 executive order by President Biden, promulgated a new proposed rule on November 18, 2021, that aims to restate the broader, pre-2015 definition of "waters of the United States". This proposed rule was subject to public comment through February 7, 2022 and if implemented, may result in expansion of the CWA by the EPA or state agencies taking a more expansive view of their respective enforcement roles. Also, 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 to reduce methane emissions from existing oil and natural gas sources, which are currently subject to public comment with a final rule forthcoming in 2022. 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 continues to pursue 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 and as a result Pennsylvania is expected to join the RGGI in the second quarter of 2022. 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.

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

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;

- 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) could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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. Legislation has been previously proposed that would, if enacted into law, make significant changes to United States federal income tax laws, including the elimination of certain United States federal income tax benefits currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs and; (iii) an extension of the amortization period for certain geological and geophysical expenditures. However, it is unclear whether any such changes will be enacted and if enacted, how soon any such changes would be effective. 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, 2021, we had a tax basis of $358.3 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. As discussed elsewhere, future asset sales may or may not be completed and depending on commodity prices, we may not generate taxable income. 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 subordinated 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. We expect our quarterly cash dividend will be reinstated in the second half of 2022.

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, 2019 to December 31, 2021 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 $26.48 per share. From January 1, 2022 to February 18, 2022, our common stock ranged from a low of $16.71 per share to a high of $22.50 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. 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. Cyber-attacks 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 cyber-attack 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 cyber-attack on a vendor or a service provider could result in supply chain disruptions, which could delay or halt development projects. A cyber-attack 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. Cyber-attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, phishing, ransomware, attempts to gain unauthorized access to data, and 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. 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.

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 the Middle East 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.

On March 4, 2021 a putative class action lawsuit was filed in the Western District of Pennsylvania in Case No. 2:21-CV-301 (Jacobowitz v. Range Resources Corporation et al.) in which the Plaintiff seeks to represent a class of Range stockholders who purchased or acquired stock from April 29, 2016 to February 10, 2021. This lawsuit was transferred to the U.S. District Court for the Northern District of Texas (Fort Worth Division). The lawsuit claims that Range misclassified certain wells as inactive rather than having plugged the wells and that such alleged misclassification affected the determination of our asset retirement obligation accrual. The lawsuit claims that the disclosure of a $294,000 agreed penalty that we paid to the DEP in connection with the DEP's investigation of our application for inactive status for a small number of our wells which the DEP disclosed during market hours on February 10, 2021, was the basis for the Plaintiffs' discovery of the alleged misrepresentations. We maintain that the factual allegations and the claims made in the litigation are baseless; there were no misrepresentations made and our asset retirement obligation was properly calculated. We also maintain that the market fully absorbed the information disclosed by the DEP on February 10, 2021 and the stock price on that day did not decrease. Given our view of the litigation as baseless, we are vigorously defending the litigation and have moved for its dismissal. Additionally, on January 20, 2022, a derivative action styled as Lewis V. Ventura et al. was filed under seal in the Northern District of Texas (Case No. 4-22CT-051-0) asserting similar allegations as the previously described Jacobowitz matter. We maintain the same views as to the merits of the Lewis matter as the Jacobowitz matter as more fully detailed above and we plan to vigorously defend the matter.

Environmental Proceedings

Our subsidiary, Range Resources – Appalachia, LLC, was notified by the DEP that it intends to assess a civil penalty under the Clean Streams Law and the 2012 Oil and Gas Act in connection with one well in Lycoming County and ordered us to conduct certain remedial work and monitoring to prevent methane and other substances from allegedly escaping the gas well into the surrounding environment including into soil, groundwater, streams and other surrounding water sources. DEP initially issued an order specifying its demands to the subsidiary on May 11, 2015. We appealed the order and the appeal was subsequently settled and discontinued whereupon we agreed to conduct certain, limited remedial work at the one well and continue monitoring water sources in the area and DEP did not assess any fines at that time. Thereafter, on January 13, 2020, DEP issued a new order regarding the same one well in Lycoming County which set forth similar allegations and demands as set forth above. This new order was issued despite considerable data and evidence presented to DEP over the course of the investigation, that this one well has not been nor is currently the source of methane in the environment nor any water supplies, but rather the methane existed in the environment before the commencement of our operations. We appealed the January 2020 order and intend to vigorously defend against the allegations asserted by DEP; however, a resolution of this matter may nonetheless result in monetary sanctions more than $250,000.

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 2021, trading volume averaged approximately 5.1 million shares per day.

Holders of Record

Pursuant to the records of our transfer agent, as of February 18, 2022, there were approximately 902 holders of record of our common stock.

Dividends

The payment of dividends is subject to the formal declaration by the board of directors. The board of directors declared quarterly dividends of $0.02 per common share for each of the four quarters of 2019 before suspending the dividend in January 2020. We expect our quarterly cash dividend will be reinstated in the second half of 2022. 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 2022 Proxy Statement, which will be filed with the SEC not later than 120 days after December 31, 2021.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

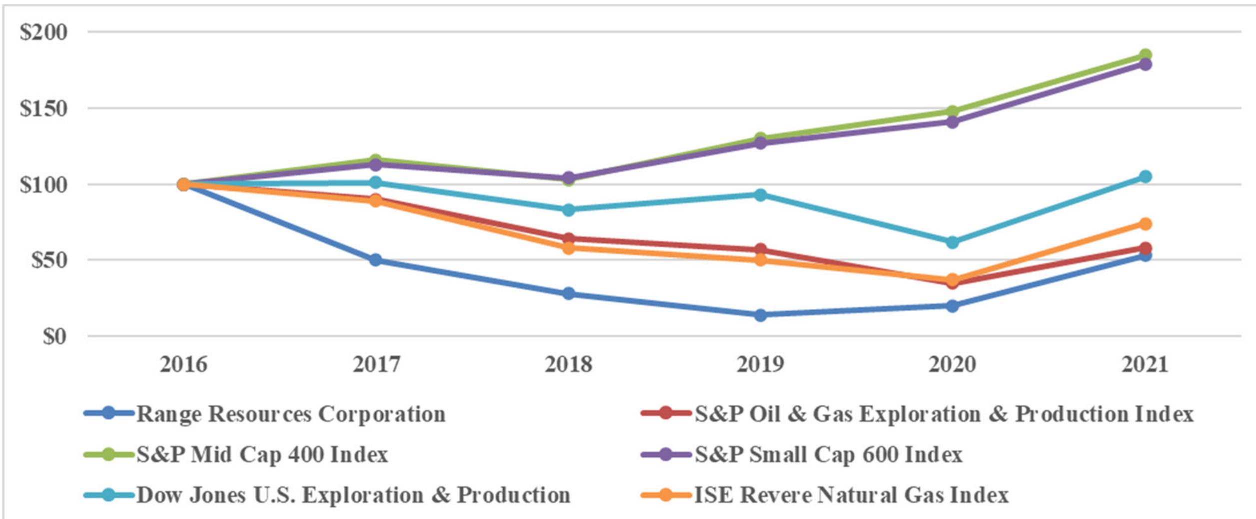
Purchases of our common stock are as follows:

	Three Months Ended December 31, 2021			
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 2021	—	$ —	—	$ 70,099,593
November 2021	—	$ —	—	$ 70,099,593
December 2021	—	$ —	—	$ 70,099,593
	—		—	

(a) In October 2019, our board of directors authorized a $100 million common stock repurchase program. As of December 31, 2021, we had repurchased 10.0 million shares of common stock at a cost of approximately $30.0 million, excluding fees and commissions. As of December 31, 2021, these 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, the S&P Mid Cap 400 Index, the S&P Small Cap 600 Index, the Dow Jones U.S. Exploration & Production Index and the ISE Revere Natural Gas Index for the five years ended December 31, 2021. We have added an index used in our stockholder return graph when compared to the previous year to better align with our market capitalization and to include on index that is widely recognized and used. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2016 and that dividends were reinvested.



	2016	2017	2018	2019	2020	2021
Range Resources Corporation	$ 100	$ 50	$ 28	$ 14	$ 20	$ 53
S&P Oil & Gas Exploration & Production Index	100	90	64	57	35	58
S&P Mid Cap 400 Index	100	116	103	130	148	185
S&P Small Cap 600 Index	100	113	104	127	141	179
Dow Jones U.S. Exploration & Production	100	101	83	93	62	105
ISE Revere Natural Gas Index	100	89	58	50	37	74

* The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

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, 2021 and 2020. For similar discussions of the year ended December 31, 2020 compared to December 31, 2019 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, 2020, which was filed with the SEC on February 23, 2021.

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 flow 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 program with the expectation of funding our capital expenditures with operating cash flows and, if required, with borrowings under our bank credit facility;
- 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 2021 highlights include:

Maintained focus on our balance sheet and liquidity

- In first quarter 2021, we issued an aggregate principal amount of $600.0 million in new 8.25% senior notes due 2029 and used the proceeds to repay a portion of the outstanding balance on our bank credit facility. We ended the year 2021 with no borrowings under our bank credit facility, $214.4 million of cash on hand and $2.1 billion available under our bank credit facility. In early January 2022, we issued an additional aggregate principal amount of $500.0 million in new 4.75% senior notes due 2030 and used those proceeds, along with cash on hand and our bank credit facility, to fully redeem our 9.25% senior notes due 2026 in early February 2022. The table below details the changes in our outstanding debt principal balances from December 31, 2020 to December 31, 2021 (in thousands):

	December 31, 2020	Change	December 31, 2021
Bank debt	$ 702,000	$ (702,000)	$ —
Senior notes			
5.75% senior notes due 2021	25,496	(25,496)	—
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
Other senior notes	490	(490)	—
Total senior notes	2,376,438	574,014	2,950,452
Senior subordinated notes			
5.75% senior subordinated notes due 2021	19,896	(19,896)	—
5.00% senior subordinated notes due 2022	9,730	(9,730)	—
5.00% senior subordinated notes due 2023	7,712	(7,712)	—
Total senior subordinated notes	37,338	(37,338)	—
Total debt	3,115,776	(165,324)	2,950,452
Cash balance (as disclosed on balance sheet)	(458)	(213,964)	(214,422)
Total debt, net of cash	$ 3,115,318	$ (379,288)	$ 2,736,030

- Our banks' committed borrowing capacity remained at $2.4 billion after completing our semi-annual borrowing base redetermination in both March and September 2021;
- In 2021, we generated $792.9 million in cash provided by operating activities, reflecting higher commodity prices which was more than sufficient to fund our capital expenditures; and
- We ended the year with a cash balance of $214.4 million.

Financial and operational results

- Continued to deliver our strong operational execution along with focusing on cost control that will improve our cost structure for current and future operations while emphasizing safety and protection of the environment.
- Focused on capital efficiencies, which resulted in lower well costs and drove overall capital spending $10.6 million lower than the original budget for the year;
- Improved our drilling and completion costs per foot compared to 2020; and
- Increased proved reserves to 17.8 Tcfe, 3% higher than 2020.

Continued to focus on safe, responsible and sustainable operations

- Expanded our goal of net zero GHG emissions by 2025 to include Scope 1 and Scope 2 emissions;
- Committed to a pilot program to certify our responsibly sourced natural gas;
- Continued to recycle approximately 100% of produced water; and
- Continued quarterly leak detection inspections.

Management's Discussion and Analysis of Results of Operations

Commodity prices have remained volatile. Benchmarks for natural gas, oil and NGLs increased in 2021 compared to 2020. As a result, we experienced significant increases in our price realizations when compared to the same period of 2020. We had many operational, financial and strategic successes in 2021 as we continued to focus on enhancing margins and returns, driving operational efficiencies and maintaining liquidity. We believe we have positioned ourselves for long-term success through the commodity price cycles.

Overview of 2021 Results

For the year ended December 31, 2021, we experienced an increase in revenue from the sale of natural gas, NGLs and oil due to a 86% increase in net realized prices (average prices including all derivative settlements and third-party transportation costs paid by us) partially offset by 5% lower production volumes when compared to 2020. Daily production in 2021 averaged 2.1 Bcfe compared to 2.2 Bcfe in 2020 reflecting the impact of the sale of our North Louisiana properties. Average natural gas differentials were below NYMEX but slightly improved from the prior year. Direct operating costs were lower when compared to the same period of 2020.

During 2021, we recognized net income of $411.8 million, or $1.61 per diluted common share compared to net loss of $711.8 million, or $2.95 per diluted common share during 2020. The improvement in net income for the year ended December 31, 2021 when compared to 2020 is due to significantly higher realized prices, lower proved property impairment charges and lower divestiture contract obligation expenses, which in the prior year were related to the sale of our North Louisiana assets, partially offset by lower gain on sale of assets and higher deferred compensation plan expenses.

During 2021, our financial and operating performance included the following results:

- reduced total debt $165.3 million and increased cash on hand $214.0 million;
- increased cash flow from operating activities by 195% from the same period of 2020;
- spent $10.6 million less than our initial 2021 capital budget of $425.0 million;
- drilled 58.1 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 by100% from the same period of 2020 with a 110% increase in average realized prices (before cash settlements on our derivatives) partially offset by slightly lower production volumes;
- increased revenue from the sale of natural gas, NGLs and oil (including settlements on our derivatives) by 38% from the same period of 2020;
- reduced direct operating expense per mcfe 9% from 2020;
- increased general and administrative expenses per mcfe by 10% from 2020 due to higher legal expenses and settlements;
- reduced our DD&A rate per mcfe 2% from 2020;
- issued $600.0 million of new senior notes and used the proceeds to reduce borrowings under our bank credit facility;
- entered into additional commodity-based derivative contracts for 2022 through 2024; and
- ended the year with cash on hand of $214.4 million and stockholders' equity of $2.1 billion.

We generated $792.9 million of cash flow from operating activities in 2021, an increase of $524.3 million from 2020 which reflects significantly higher realized prices and lower net operating costs somewhat offset by higher comparative working capital outflows ($241.7 million outflow during 2021 compared to $53.9 million outflow in 2020) due to higher commodity prices. We ended 2021 with $2.1 billion of available committed borrowing capacity.

Acquisitions

During 2021, we spent $22.0 million to acquire unproved acreage compared to $26.2 million in 2020. We continue selective acreage leasing and lease renewals to consolidate our acreage positions in the Marcellus Shale play in Pennsylvania.

Divestitures

Our gain (loss) on sale of assets is primarily attributable to the following divestitures (in thousands):

Asset Sold	Completion Date	Gain (Loss) on Sale of Assets
Year Ended December 31, 2021:		
North Louisiana assets	August 2020	$ 479
Other	Various	$ 222
Year Ended December 31, 2020:		
North Louisiana assets	August 2020	$ (9,503)
Shallow legacy assets in Northwest Pennsylvania	March 2020	$ 122,506
Other	Various	$ (2,212)

2022 Outlook

As we enter 2022, we believe we are positioned for sustainable long-term success. For 2022, we expect our capital budget to be in the range of $460.0 million to $480.0 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 2022 capital budget to achieve production similar to our 2021 production. Our 2022 capital budget is designed to focus on continuing to improve corporate returns and generating free cash flow. To the extent commodity prices decline, we may reduce the capital budget with the intent of limiting capital spending to at or below 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 2022 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 2022.

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 2021 when compared to the same period of 2020 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, global inventories of oil and gas and the uncertainty associated with recovering oil demand, future monetary policy and governmental policies aimed at redirecting fossil fuel consumption towards lower carbon energy, we expect prices for some or all of the commodities we produce to remain volatile. NYMEX natural gas futures have shown strong improvements 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 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 U.S. LNG exports and domestic industrial gas demand. Other factors such as the duration of the COVID-19 pandemic and the speed and effectiveness of vaccine distributions or other medical advances to combat the virus may impact the recovery of world economic growth and the demand for oil, natural gas and NGLs.

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 increased, when compared to December 2021, with the average NYMEX monthly settlement price for natural gas increasing to $6.27 per mcf for February 2022 with the recent colder weather and a decline in natural gas storage inventories. Crude oil prices have also increased, when compared to December 2021, to $82.98 per barrel in January 2022. The following table lists related benchmarks for natural gas, oil and NGLs composite prices for the years ended December 31, 2021 and 2020.

	Year Ended December 31,	
	2021	2020
Benchmarks:		
Average NYMEX prices [a]		
Natural gas (per mcf)	$ 3.88	$ 2.06
Oil (per bbl)	$ 67.93	$ 39.66
Mont Belvieu NGLs composite (per gallon) [b]	$ 0.74	$ 0.37

(a) Based on average of bid week prompt month 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 2021, natural gas, NGLs and oil sales increased 100% from 2020 with a 5% decrease in production and a 110% 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,			
	2021	2020	Change	% Change
Natural gas, NGLs and Oil sales				
Natural gas	$ 1,896,231	$ 943,740	$ 952,491	101%
NGLs	1,135,826	578,454	557,372	96%
Oil and condensate	182,970	85,519	97,451	114%
Total natural gas, NGLs and oil sales	$ 3,215,027	$ 1,607,713	$ 1,607,314	100%

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 and asset sales. For 2021, our production decreased 5% reflecting the impact of the sale of our North Louisiana properties. Production from our North Louisiana properties was 38.0 Bcfe in 2020 with the sale of these properties closing in August 2020. Our production for the last two years is set forth in the following table:

	Year Ended December 31,			
	2021	2020	Change	% Change
Production [(a)]				
Natural gas (mcf)	541,021,442	574,529,290	(33,507,848)	(6%)
NGLs (bbls)	36,372,862	37,491,546	(1,118,684)	(3%)
Crude oil and condensate (bbls)	3,044,026	2,829,495	214,531	8%
Total (mcfe) [(b)]	777,522,772	816,455,536	(38,932,764)	(5%)
Average daily production [(a)]				
Natural gas (mcf)	1,482,251	1,569,752	(87,501)	(6%)
NGLs (bbls)	99,652	102,436	(2,784)	(3%)
Crude oil and condensate (bbls)	8,340	7,731	609	8%
Total (mcfe) [(b)]	2,130,199	2,230,753	(100,554)	(5%)

(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 2021 was $1.92 per mcfe compared to $1.03 per mcfe in 2020. 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,			
	2021	2020	Change	% Change
Average Prices				
Average sales prices (excluding derivative settlements):				
Natural gas (per mcf)	$ 3.50	$ 1.64	$ 1.86	113%
NGLs (per bbl)	31.23	15.43	15.80	102%
Crude oil (per bbl)	60.11	30.22	29.89	99%
Total (per mcfe) [(a)]	4.13	1.97	2.16	110%
Average realized prices (including all derivative settlements):				
Natural gas (per mcf)	$ 2.74	$ 2.09	$ 0.65	31%
NGLs (per bbl)	28.70	15.73	12.97	82%
Crude oil (per bbl)	46.16	48.79	(2.63)	(5%)
Total (per mcfe) [(a)]	3.43	2.36	1.07	45%
Average realized prices (including all derivative settlements and third-party transportation costs paid by Range):				
Natural gas (per mcf)	$ 1.51	$ 0.96	$ 0.55	57%
NGLs (per bbl)	14.64	4.06	10.58	260%
Crude oil (per bbl)	45.86	48.46	(2.60)	(5%)
Total (per mcfe) [(a)]	1.92	1.03	0.89	86%

(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,	
	2021	2020
Average natural gas differentials below NYMEX	$ (0.38)	$ (0.42)
Realized gains on basis hedging	$ 0.04	$ 0.06

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,			
	2020	Price Variance	Volume Variance	2021
Natural gas				
Price (per mcf)	$ 1.64	$ 1.86	$ —	$ 3.50
Production (Mmcf)	574,529	—	(33,508)	541,021
Natural gas sales	$ 943,740	$ 1,007,532	$ (55,041)	$ 1,896,231

	Year Ended December 31,			
	2020	Price Variance	Volume Variance	2021
NGLs				
Price (per bbl)	$ 15.43	$ 15.80	$ —	$ 31.23
Production (Mbbls)	37,492	—	(1,119)	36,373
NGLs sales	$ 578,454	$ 574,632	$ (17,260)	$ 1,135,826

	Year Ended December 31,			
	2020	Price Variance	Volume Variance	2021
Crude oil				
Price (per bbl)	$ 30.22	$ 29.89	$ —	$ 60.11
Production (Mbbls)	2,829	—	215	3,044
Crude oil sales	$ 85,519	$ 90,967	$ 6,484	$ 182,970

	Year Ended December 31,			
	2020	Price Variance	Volume Variance	2021
Consolidated				
Price (per mcfe)	$ 1.97	$ 2.16	$ —	$ 4.13
Production (Mmcfe)	816,456	—	(38,933)	777,523
Total natural gas, NGLs and oil sales	$ 1,607,713	$ 1,683,977	$ (76,663)	$ 3,215,027

Transportation, gathering, processing and compression expense was $1.2 billion in 2021 compared to $1.1 billion in 2020. These third-party costs are higher due to the impact of higher NGLs prices which result in higher processing costs and higher fuel costs somewhat offset by the sale of our North Louisiana assets in third quarter 2020 and transportation capacity released in Pennsylvania in 2020. 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,			
	2021	2020	Change	% Change
Natural gas	$ 661,990	$ 650,071	$ 11,919	2%
NGLs	511,568	437,474	74,094	17%
Oil	911	945	(34)	(4%)
Total	$ 1,174,469	$ 1,088,490	$ 85,979	8%
Natural gas (per mcf)	$ 1.22	$ 1.13	$ 0.09	8%
NGLs (per bbl)	$ 14.06	$ 11.67	$ 2.39	20%
Oil (per bbl)	$ 0.30	$ 0.33	$ (0.03)	(9%)

Derivative fair value (loss) income was a loss of $650.2 million in 2021 compared to income of $187.7 million in 2020. 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, 2021, our commodity derivative contracts were recorded at their fair value, which was a net derivative liability of $169.5 million, an increase of $151.5 million from the $18.0 million net derivative liability recorded as of December 31, 2020. 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 $16.0 million as of December 31, 2021 compared to a net derivative asset of $3.7 million as of December 31, 2020. As of December 31, 2021, we have propane basis swaps to limit the volatility caused by changing differentials between Mont Belvieu and international propane indexes which are recognized as a net derivative asset of $123,000 as of December 31, 2021 compared to a net derivative asset of $794,000 as of December 31, 2020. In connection with our international propane swaps, we also have freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange which are recognized as a net derivative asset of $114,000 as of December 31, 2021 compared to a net derivative asset of $1.1 million as of December 31, 2020. The following table summarizes the impact of our commodity derivatives for the last two years (in thousands):

	Year Ended December 31,	
	2021	2020
Derivative fair value (loss) income per consolidated statements of operations	$ (650,216)	$ 187,711
Non-cash fair value (loss) gain: [(1)]		
Natural gas derivatives	$ (130,114)	$ (132,978)
Oil derivatives	(23,879)	519
NGLs derivatives	14,100	(3,004)
Freight derivatives	(990)	(425)
Contingent consideration	10,680	970
Total non-cash fair value loss [(1)]	$ (130,203)	$ (134,918)
Net cash (payment) receipt on derivative settlements:		
Natural gas derivatives	$ (415,228)	$ 258,797
Oil derivatives	(42,447)	52,544
NGLs derivatives	(91,838)	11,288
Contingent consideration	29,500	—
Total net cash (payment) receipt	$ (520,013)	$ 322,629

(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 $365.4 million in 2021 compared to $173.3 million in 2020. 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 2021 period includes $342.4 million of revenue from the sale of natural gas that is not related to our production (brokered) and $6.9 million of revenue from the sale of NGLs that is not related to our production. The 2020 period includes $160.1 million of revenue from the brokered sale of natural gas and $3.8 million of revenue from the sale of NGLs that is not related to our production. These revenues increased compared to 2020 due to higher brokered volumes and higher sales prices. 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,			
	2021	2020	Change	% Change
Direct operating expense	$ 0.10	$ 0.11	$ (0.01)	(9%)
Production and ad valorem tax expense	0.04	0.03	0.01	33%
General and administrative expense	0.22	0.20	0.02	10%
Interest expense	0.29	0.24	0.05	21%
Depletion, depreciation and amortization expense	0.47	0.48	(0.01)	(2%)

Direct operating expense was $75.3 million in 2021 compared to $92.2 million in 2020. 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 2021 decreased 18% from the prior year primarily due to the impact of the sale of our higher cost North Louisiana assets in third quarter 2020 and lower workover costs. We incurred $3.4 million of workover costs in 2021 compared to $7.3 million of workover costs in 2020.

On a per mcfe basis, operating expense for 2021 decreased $0.01, or 9% from the same period of 2020, with the decrease due to lower workover 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,			
	2021	2020	Change	% Change
Lease operating expense	$ 0.10	$ 0.10	$ —	—%
Workovers	—	0.01	(0.01)	(100%)
Stock-based compensation	—	—	—	—%
Total direct operating expense	$ 0.10	$ 0.11	$ (0.01)	(9%)

Production and ad valorem taxes are paid based on market prices, not hedged prices. This expense category also includes 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, 2021 includes a $29.3 million impact fee compared to $17.7 million in the year ended December 31, 2020 with the increase primarily due to higher natural gas prices. Production and ad valorem taxes (excluding the impact fee) were less than $50,000 in 2021 compared to $7.0 million in 2020 with the decline due to the sale of our North Louisiana assets in third quarter 2020. The following table summarizes production and ad valorem taxes per mcfe for the last two years:

	Year Ended December 31,			
	2021	2020	Change	% Change
Production taxes	$ —	$ 0.01	$ (0.01)	(100%)
Ad valorem taxes	—	—	—	—%
Impact fee	0.04	0.02	0.02	100%
Total production and ad valorem	$ 0.04	$ 0.03	$ 0.01	33%

General and administrative expense was $169.8 million for 2021 compared to $159.4 million for 2020. The increase in 2021, when compared to 2020, is primarily due to higher legal expenses and legal settlements of $7.7 million and higher stock-based compensation partially offset by lower salaries and benefits and lower technology costs. As of December 31, 2021, the number of general and administrative employees decreased 2% when compared to December 31, 2020.

On a per mcfe basis, general and administrative expense for 2021 increased 10% from the same period of 2020, with the increase due to higher legal expenses and legal settlements and higher stock-based compensation partially offset by lower salaries and benefits. 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,			
	2021	2020	Change	% Change
General and administrative	$ 0.17	$ 0.16	$ 0.01	6%
Stock-based compensation	0.05	0.04	0.01	25%
Total general and administrative expense	$ 0.22	$ 0.20	$ 0.02	10%

Interest expense was $227.3 million for 2021 compared to $192.7 million for 2020. The following table presents information about interest expense per mcfe for the last two years:

	Year Ended December 31,			
	2021	2020	Change	% Change
Bank credit facility	$ 0.02	$ 0.03	$ (0.01)	(33%)
Senior notes	0.26	0.20	0.06	30%
Amortization of deferred financing costs and other	0.01	0.01	—	—%
Total interest expense	$ 0.29	$ 0.24	$ 0.05	21%
Average debt outstanding (in thousands)	$ 3,100,067	$ 3,239,867	$ (139,800)	(4%)
Average interest rate [(a)]	7.0%	5.7%	1.3%	23%

(a) Includes commitment fees but excludes amortization of debt issue costs and amortization of discount.

On an absolute basis, the increase in interest expense for 2021 from the same period of 2020 was primarily due to higher average interest rates partially offset by slightly lower outstanding debt balances. See Note 7 to our consolidated financial statements for additional information. Average debt outstanding on the bank credit facility for 2021 was $144.9 million compared to $656.7 million for 2020 and the weighted average interest rate on the bank credit facility was 2.1% for 2021 compared to 2.6% in 2020.

Depletion, depreciation and amortization ("DD&A") was $364.6 million in 2021 compared to $394.3 million in 2020. The decrease in 2021 when compared to 2020 is due to a 2% decrease in depletion rates and a 5% decrease in production volumes.

On a per mcfe basis, DD&A decreased to $0.47 in 2021 compared to $0.48 in 2020. Depletion expense, the largest component of DD&A, was $0.46 per mcfe in 2021 compared to $0.47 per mcfe in 2020. 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 $0.46 per mcfe in 2022, based on our current production estimates. In areas where we are actively drilling, our fourth quarter adjusted 2021 depletion rates were slightly lower than fourth quarter 2020. The decrease in DD&A per mcfe in 2021 when compared to 2020 is due to the mix of our production from our properties with lower depletion rates and asset sales. The following table summarizes DD&A expenses per mcfe for the last two years:

	Year Ended December 31,			
	2021	2020	Change	% Change
Depletion and amortization	$ 0.46	$ 0.47	$ (0.01)	(2%)
Depreciation	—	—	—	—%
Accretion and other	0.01	0.01	—	—%
Total DD&A expenses	$ 0.47	$ 0.48	$ (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, loss (gain) on early extinguishment of debt and impairment of proved properties and other assets. The following table details stock-based compensation that is allocated to functional expense categories for the last two years (in thousands):

	2021	2020
Direct operating expense	$ 1,310	$ 1,078
Brokered natural gas and marketing expense	1,794	1,416
Exploration expense	1,507	1,279
General and administrative expense	39,673	32,905
Termination costs	—	2,165
Total stock-based compensation	$ 44,284	$ 38,843

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

Brokered natural gas and marketing expense was $367.3 million in 2021 compared to $188.3 million in 2020. 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 broker purchase volumes and higher purchase prices. 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, 2021 (in thousands):

	2021	2020
Brokered natural gas sales	$ 342,431	$ 160,122
Brokered NGLs sales	6,925	3,776
Other marketing revenue	16,056	9,375
Brokered natural gas purchases and transportation	(350,426)	(175,039)
Brokered NGLs purchases	(8,044)	(4,691)
Other marketing expense	(8,818)	(8,586)
Net brokered natural gas and marketing net margin	$ (1,876)	$ (15,043)

Exploration expense was $23.6 million in 2021 compared to $32.7 million in 2020. Exploration expense in 2021 was lower compared to the prior year due to lower delay rentals and other costs, lower personnel costs and lower seismic expenses. 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,			
	2021	2020	Change	% Change
Seismic	$ 129	$ 1,761	$ (1,632)	(93%)
Delay rentals and other	16,597	21,187	$ (4,590)	(22%)
Personnel expense	5,322	7,539	$ (2,217)	(29%)
Stock-based compensation expense	1,507	1,279	$ 228	18%
Exploratory dry hole expense	—	888	$ (888)	(100%)
Total exploration expense	$ 23,555	$ 32,654	$ (9,099)	(28%)

Abandonment and impairment of unproved properties was $7.2 million in 2021 compared to $19.3 million in 2020. These costs declined when compared to the same period of 2020 due to lower 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. In certain circumstances, our future plans to develop acreage may accelerate our impairment.

Exit and termination costs in 2021 were $21.7 million compared to $547.4 million in 2020. 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 addition, 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. In second quarter 2020, we also negotiated capacity releases on certain transportation pipelines in Pennsylvania and we recorded $10.4 million of exit costs which represents the discounted present volume of our remaining obligations. 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 and a change in our 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,	
	2021	2020
Severance costs	$ 567	$ 5,909
Transportation contract capacity releases (including accretion of discount)	754	10,900
Divestiture contract obligation (including accretion of discount)	20,340	499,935
One-time minimum volume commitment contract payment	—	28,500
Stock-based compensation	—	2,165
	$ 21,661	$ 547,409

Deferred compensation plan expense was a loss of $68.4 million in 2021 compared to a loss of $12.5 million in 2020. Our stock price increased to $17.83 at December 31, 2021 from $6.70 at December 31, 2020. 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 (gain) on early extinguishment of debt was a loss of $98,000 in 2021 compared to a gain of $14.1 million in 2020. In 2020, we purchased for cash a total of $1.0 billion aggregate principal amount of various senior and senior subordinated notes. An early cash tender of $20.4 million was paid to note holders who tendered their notes within the ten business day offer period. We recorded a loss on early extinguishment of debt of $25.5 million, net of transaction call premium costs and the expensing of the remaining deferred financing costs on the repurchased debt. Also in 2020, we purchased in the open market $161.0 million principal amount of various senior and senior subordinated notes. We recorded a gain on early extinguishment of debt of $39.6 million, net of transaction costs and the expensing of the remaining deferred financing costs.

Impairment of proved properties and other was $79.0 million in 2020. There were no proved property impairments in 2021. We assess our long-lived assets whenever events or circumstances indicate the carrying value may not be recoverable. Fair value is generally determined using an income approach based on internal estimates of future production levels, prices, drilling and operating costs and discount rates. In some cases, we may also use a market approach, based on either anticipated sales proceeds less costs to sell or a market comparable sales price. In fourth quarter 2019, we recorded impairment expense related to our North Louisiana assets due to a shift in business strategy employed by management and the possibility of a divestiture of these assets. Early in 2020, we recognized additional impairment charges of $77.0 million related to these North Louisiana assets that reduced the carrying value to the anticipated sales proceeds which is a market approach. See Note 10 to our consolidated financial statements for additional details.

Income tax (benefit) expense was a benefit of $9.7 million in 2021 compared to a benefit of $25.6 million in 2020. The 2021 decline in the income tax benefit reflects a $1.1 billion improvement in our operating income before income taxes when compared to 2020 offset by changes in our valuation allowances due to the current commodity price environment. The effective tax rate was (2.4%) in 2021 compared to 3.5% in 2020. Our current year effective tax rate was affected by the impact of a shift in our state apportionment factor for NGLs sales from higher state jurisdictions. The 2021 and 2020 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 year ended December 31, 2021, current income tax expense relates to state income taxes. The following table summarizes our tax activity for the last two years (in thousands):

	2021	2020
Total income (loss) before income taxes	$ 402,035	$ (737,329)
U.S. federal statutory rate	21%	21%
Total tax expense (benefit) at statutory rate	84,427	(154,839)
State and local income taxes, net of federal benefit	16,260	(38,413)
State rate and law change	(13,583)	(31,469)
Non-deductible executive compensation	1,414	474
Tax less than book equity compensation	1,566	4,933
Change in valuation allowances:		
Federal valuation allowances & other	(76,553)	124,631
State valuation allowances & other	(23,357)	68,836
Permanent differences and other	83	295
Total benefit for income taxes	$ (9,743)	$ (25,552)
Effective tax rate	(2.4%)	3.5%

We estimate our ability to utilize our deferred tax assets by analyzing 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):

	2021	2020
Sources of cash and cash equivalents		
Operating activities	$ 792,948	$ 268,680
Disposal of assets	303	246,127
Borrowing on credit facility	1,434,000	2,076,000
Issuance of new senior notes	600,000	850,000
Other	53,667	23,045
Total sources of cash and cash equivalents	$ 2,880,918	$ 3,463,852
Uses of cash and cash equivalents		
Additions to natural gas and oil properties	$ (393,478)	$ (405,617)
Acreage purchases	(23,962)	(26,816)
Other property	(1,231)	(2,873)
Repayments on credit facility	(2,136,000)	(1,851,000)
Repayment of senior and subordinated notes	(63,324)	(1,120,634)
Repurchases of treasury stock	—	(22,992)
Other	(48,959)	(34,008)
Total uses of cash and cash equivalents	$ (2,666,954)	$ (3,463,940)

Cash flows from operating activities are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operating activities are also impacted by changes in working capital. We have historically maintained low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and because our principal source of operating cash flows (proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. We sell a portion of our production at the wellhead under floating market contracts. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. Since year-end 2021, we have entered into additional natural gas and NGLs hedges for 2022 through 2024. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. However, production receipts often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the bank credit facility. As of December 31, 2021, we have entered into derivative agreements covering 381.3 Bcfe for 2022 and 139.2 Bcfe for 2023, not including our basis swaps.

Net cash provided from operating activities in 2021 was $792.9 million compared to $268.7 million in 2020. The increase in cash provided from operating activities is the result of a 86% increase in average realized prices (including all derivative settlements and third-party transportation costs) partially offset by a 5% decrease in production volumes. 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 2021 was an outflow of $241.7 million compared to an outflow of $53.9 million for 2020.

Disposal of assets in 2020 included proceeds of $246.1 million primarily from the sale of our North Louisiana assets.

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 by region 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):

	2021	2020
Appalachia	$ 391,483	$ 378,509
North Louisiana	—	1,987
Total	391,483	380,496
Change in capital expenditure accrual for proved properties	1,995	25,121
Additions to natural gas and oil properties	$ 393,478	$ 405,617

Repayment of senior notes for 2021 includes the redemption of all of our senior subordinated notes due 2021, 2022 and 2023 and our senior notes due 2021. The prior year includes open market purchases of $161.0 million aggregate principal amount of various senior and senior subordinated notes due 2021, 2022 and 2023. In addition, 2020 also included two transactions where we repurchased $1.0 billion aggregate principal amount of various senior and senior subordinated notes due 2021, 2022 and 2023 where we paid an early cash tender to those note holders who tendered their notes within a ten business day offer period.

Liquidity and Capital Resources

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. As of December 31, 2021, we had cash on hand in the amount of $214.4 million.

Sources of Cash

We currently expect our 2022 capital program to be funded by cash flows from operations. During the year ended December 31, 2021, we generated $792.9 million of cash flows from operating activities. As of December 31, 2021, the remaining available borrowing capacity under our bank credit facility was $2.1 billion and we had $214.4 million 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. In early January 2022, we issued $500.0 million aggregate principal amount of new 4.75% senior notes due 2030, with the proceeds along with cash on hand used to fully redeem our 9.25% senior notes due 2026 in February 2022.

Although we expect cash flows and capacity under the existing credit facility to be sufficient to fund our expected 2022 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

Our bank credit facility is secured by substantially all of our assets and has a maturity date of April 13, 2023. As of December 31, 2021, we had no outstanding borrowings under our bank credit facility and we maintain a borrowing base of $3.0 billion and aggregate lender commitments of $2.4 billion. We also have undrawn letters of credit of $338.0 million as of December 31, 2021.

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 2022. We expect to extend the maturity of our bank credit facility prior to its current maturity date and plan to right-size the facility to provide us with sufficient access to liquidity. The terms of the facility are expected to reflect market, however the size and terms are uncertain at this time. 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, 2021.

Our daily weighted-average bank credit facility debt balance was $144.9 million for the year ended December 31, 2021 compared to $656.7 million for the year ended December 31, 2020. 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 LIBOR Rate (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 LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR 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. Expenditures for the development, exploration and acquisition of natural gas and oil properties are the primary use of our capital resources. During 2021, we spent $418.7 million on capital expenditures as reported in our consolidated statement of cash flows. The amount of our future capital expenditures will depend upon a number of factors including our cash flows from operating, investing and financing activities 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. As part of our strategy for 2022, we will continue to focus on improving our debt metrics.

We expect our quarterly cash dividend to be reinstated in the second half of 2022. Details regarding the record and payment dates will be announced at such time the dividend is declared by our board of directors. In early 2022, the board approved an increase to our share repurchase program, where we are now authorized to repurchase an additional $500.0 million of our outstanding shares of common stock.

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.

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,	
	2021	2020
	(Mmcfe)	
Proved Reserves:		
Beginning of year	17,203,114	18,191,583
Reserve additions	1,602,769	1,264,283
Reserve revisions	(252,876)	(608,211)
Sales	—	(828,085)
Production	(777,523)	(816,456)
End of year	17,775,484	17,203,114
Proved Developed Reserves:		
Beginning of year	9,792,540	9,902,467
End of year	10,417,887	9,792,540

Our proved reserves at year-end 2021 were 17.8 Tcfe compared to 17.2 Tcfe at year-end 2020. Natural gas comprised approximately 64% of our proved reserves at year-end 2021.

Reserve Additions and Revisions. 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. During 2020, we added 1.3 Tcfe of proved reserves from drilling activities and evaluation of proved areas in Pennsylvania. Approximately 80% of the 2020 reserve additions are attributable to natural gas. Revisions of previous estimates of a negative 608.2 Bcfe includes 961.1 Bcfe reserves reclassified to unproved because of previously planned wells not expected to be drilled within the original five year development horizon, negative pricing revisions of 67.9 Bcfe somewhat offset by positive performance revisions of 420.8 Bcfe.

Sales. In 2020, we sold 828.1 Bcfe of reserves related to the sale of our North Louisiana assets.

Future Net Cash Flows. At December 31, 2021, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $14.9 billion. The present value of our estimated future net cash flows at December 31, 2020 was $3.0 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, 2021, the after-tax present value of estimated future net cash flows from our proved reserves was $12.5 billion compared to $2.8 billion at December 31, 2020.

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.

Capitalization and Dividend Payments

As of December 31, 2021 and 2020, our total debt and capitalization were as follows (in thousands):

	2021	2020
Bank debt	$ —	$ 693,123
Senior notes	2,925,787	2,355,223
Senior subordinated notes	—	37,261
Total debt	2,925,787	3,085,607
Stockholders' equity	2,085,663	1,637,535
Total capitalization	$ 5,011,450	$ 4,723,142
Debt to capitalization ratio	58.4%	65.3%

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, 2021, 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, 2021, we had a total of $338.0 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, 2021. In addition to the contractual obligations listed in the table below, our consolidated balance sheet at December 31, 2021 reflects accrued interest payable on our bank debt of $1.6 million, which is payable in first quarter 2022. We expect to make annual interest payments through the end of each note maturity, based upon the amounts outstanding at December 31, 2021, of $36.6 million on our 4.875% senior notes, $35.1 million on our 5.00% senior notes, $2.9 million on our 5.875% senior notes, $49.5 million on our 8.25% senior notes and $78.6 million on our 9.25% senior notes. We redeemed in full the 9.25% senior notes in February 2022.

The following summarizes our contractual financial obligations at December 31, 2021 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					
	2022	2023	2024	2025 and 2026	Thereafter	Total
Debt:						
Bank debt due 2023 [(a)]	$ —	$ —	$ —	$ —	$ —	$ —
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
Other obligations:						—
Operating leases, net	21,282	7,207	6,546	12,635	2,627	50,297
Software licenses and other	2,767	2,191	51	64	16	5,089
Derivative obligations [(b)]	162,767	8,565	—	—	—	171,332
Transportation and gathering commitments[(c)]	801,974	784,712	768,059	1,305,611	3,520,105	7,180,461
Asset retirement obligation liability [(d)]	5,310	50	—	—	90,476	95,836
Total contractual obligations [(e)]	$ 1,212,217	$ 1,335,060	$ 774,656	$ 2,918,310	$ 4,213,224	$ 10,453,467

(a) As of December 31, 2021, we had no outstanding borrowings under our bank credit facility.

(b) Derivative obligations represent net liabilities determined in accordance with master netting arrangements for commodity derivatives that were valued as of December 31, 2021. 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, 2021. 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 25,000 mcf per day and is expected to begin in 2022 with a six-year term.

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, 2021, the carrying value of this obligation was $416.4 million (discounted) and is included in divestiture contract obligation in our consolidated balance sheet. As of December 31, 2021, our estimated settlement of this retained obligation based on a discounted value is as follows (in thousands):

		Year Ended December 31,
2022	$	91,120
2023		71,277
2024		58,401
2025		51,688
2026		36,971
Thereafter		106,942
	$	416,399

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, 2021, our delivery commitments through 2031 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2022	588,158	55,000
2023	500,710	39,932
2024	253,566	35,000
2025	182,493	35,000
2026	158,301	35,000
2027	100,000	35,000
2028	100,000	35,000
2029	100,000	20,000
2030	—	20,000
2031	—	20,000

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 3,000 bbls per day starting in 2022, increasing to 18,000 bbls per day in 2027 and increasing again to 25,000 bbls per day in 2029 then declining to 10,000 bbls per day in 2034 and declining again to 3,000 bbls per day through the end of the term in 2037.

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, 2021, we had $2.9 billion of debt outstanding which bears interest at fixed rates averaging 6.9%. In January 2022, we issued $500.0 million of 4.75% senior notes due 2030 and we used the proceeds, along with cash on hand and our bank credit facility to fully redeem our 9.25% senior notes. After this transaction, our debt outstanding will bear interest at fixed rates averaging 5.7%.

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.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. We expect costs in 2022 to continue to be a function of supply and demand. Natural gas, NGLs and oil prices have remained volatile and unpredictable. However, we continue to focus on improving our cost structure.

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 97% of our reserves in both 2021 and 2020. 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, 2021 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, 2021, 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, 2021, we estimate that a 1% change in proved reserves would increase or decrease 2022 depletion expense by approximately $4.0 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,
- recorded value of certain derivative instruments and
- the initial recording of retained liabilities.

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 $30.0 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. During 2019, a change in business strategy employed by management in North Louisiana and the possibility of a divestiture of these assets triggered an assessment of these long-lived assets for impairment. We estimated the fair values using a discounted net cash flow model or an income approach and we recognized an impairment. As of December 31, 2021, our estimated undiscounted cash flows relating to our remaining 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.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore the surface at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation (“ARO”), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. See Note 8 to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates. In addition, increases in the discounted ARO resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates. An estimate of the sensitivity to operating results of other assumptions that had been used in recording these liabilities is not practical because of the number of obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

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. 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 2021, we decreased our valuation allowances against our state net operating loss carryforwards, basis differences and credits from $226.5 million as of December 31, 2020 to $203.1 million as of December 31, 2021. The federal valuation allowances decreased from $152.5 million as of December 31, 2020 to $68.0 million as of December 31, 2021. 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 64% of our December 31, 2021 proved reserves were natural gas compared to 2% of proved reserves were oil. In addition, a portion of our NGLs, which are 34% 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, 2020 to December 31, 2021.

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. We have also entered into combined natural gas derivative instruments containing a fixed price swap and a sold option to extend the term or expand the volume (which we refer to as a swaption). The swap price is a fixed price determined at the time of the swaption contract. If the option is exercised, the contract will become a swap treated consistently with our fixed-price swaps. 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, 2021, our derivatives program includes swaps, swaptions, collars and calls. These contracts expire monthly through December 2023. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2021, approximated a net derivative liability of $169.5 million compared to a net derivative liability of $18.0 million at December 31, 2020. This change is primarily related to the settlements of derivative contracts during 2021 and to the natural gas, NGLs and oil futures prices as of December 31, 2021 in relation to the new commodity derivative contracts we entered into during 2021 for 2022 and 2023. At December 31, 2021, the following commodity derivative contracts were outstanding, excluding our basis and freight swaps and divestiture contingent consideration, which are separately discussed below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price				Fair Market Value
			Swap	Sold Put	Floor	Ceiling	(in thousands)
Natural Gas [1]							
2022	Swaps	497,479 Mmbtu/day	$ 3.12				$ (102,097)
2022	Collars	224,301 Mmbtu/day			$ 3.28	$ 3.73	$ (10,881)
2022	Three-way Collars	251,781 Mmbtu/day		$ 2.37	$ 3.03	$ 3.77	$ (27,219)
Jauary-March 2022	Calls	80,000 Mmbtu/day				$ 6.02	$ (61)
2023	Swaps	197,500 Mmbtu/day	$ 3.40				$ 2,829
2023	Collars	110,000 Mmbtu/day			$ 3.26	$ 4.26	$ 6,680
2023	Three-way Collars	70,000 Mmbtu/day		$ 2.25	$ 3.25	$ 4.28	$ 2,287
Crude Oil							
2022	Swaps	6,437 bbls/day	$ 60.73				$ (26,812)
2023	Swaps	623 bbls/day	$ 66.40				$ (72)
NGLs (C5-Natural Gasoline)							
January-June 2022	Swaps	2,749 bbls/day	$1.65/gallon				$ (1,782)
January-June 2022	Collars	1,497 bbls/day			$1.53/gallon	$1.67/gallon	$ (1,272)

(1) We also sold natural gas call swaptions of 72,500 Mmbtu/day for 2023 at a weighted average price of $3.06 per Mmbtu. The fair value of these swaptions at December 31, 2021 was a net derivative liability of $11.1 million.

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 2024, was a net derivative asset of $16.0 million at December 31, 2021 and the volumes are for 213,710,000 Mmbtu.

As of December 31, 2021, we also had propane spread swap contracts which lock in the differential between Mont Belvieu and international propane indices. These contracts settle monthly in first quarter 2022 and the fair value of these contracts was a net derivative asset of $123,000 on December 31, 2021.

In connection with our international propane swaps, at December 31, 2021, we had freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange. These contracts settle monthly and cover 7,000 metric tons in first quarter 2022 with a fair value net derivative asset of $114,000 on December 31, 2021.

We have the right to receive contingent consideration in conjunction with the sale our North Louisiana assets of up to $45.5 million based on future realization of natural gas and oil prices based on published indexes and realized NGLs prices of the buyer for the years 2022 and 2023. The fair value of this instrument on December 31, 2021 was a derivative asset of $26.6 million. In addition, we expect to receive $29.5 million for the year ended December 31, 2021 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, 2021. 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	$ (127,934)	$ (112,125)	$ (280,313)	$ 112,125	$ 280,313
Calls	(61)	(89)	(382)	44	59
Collars	(5,473)	(35,607)	(90,902)	35,297	90,598
Three-way collars	(24,932)	(31,383)	(79,909)	29,920	66,447
Basis swaps	16,151	8,038	20,095	(8,038)	(20,095)
Swaptions	(11,149)	(7,066)	(19,327)	5,424	9,788
Freight swaps	114	123	307	(123)	(307)
Divestiture contingent consideration	26,640	3,810	7,930	(4,910)	(13,480)

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, 2021, our derivative counterparties include fifteen financial institutions, of which all but five 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. Our propane and butane sales from the Marcus Hook facility near Philadelphia were short-term and are to a single purchaser and our ethane sales from Marcus Hook were to a single international customer bearing a credit rating similar to Range. Since April 1, 2021, other than limited spot sales, our propane and butane sales have been diversified among several purchasers and are for set terms of twelve to twenty-four months.

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, 2021, we had $2.9 billion of debt outstanding which bears interest at a fixed rate averaging 6.9%. As of December 31, 2021, we had no variable rate bank debt outstanding compared to variable rate bank debt of $702.0 million at December 31, 2020. 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. In January 2022, we issued $500.0 million of 4.75% senior notes due 2030 with the proceeds, along with cash on hand and our credit facility, being used to fully deem our 9.25% senior notes. After this transaction, our debt outstanding will bear interest at a fixed rate averaging 5.7%. See Note 7 to our consolidated financial statements for more information about our new senior notes.

The fair value of our senior and subordinated debt is based on December 31, 2021 quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Notes due 2022	$ 169,589	$ 171,488
(The interest rate is fixed at a rate of 5.00%)		
Senior Notes due 2022	48,528	48,955
(The interest rate is fixed at a rate of 5.875%)		
Senior Notes due 2023	532,335	543,471
(The interest rate is fixed at a rate of 5.00%)		
Senior Notes due 2025	750,000	776,153
(The interest rate is fixed at a rate of 4.875%)		
Senior Notes due 2026 (1)	850,000	916,929
(The interest rate is fixed at a rate of 9.25%)		
Senior Notes due 2029	600,000	669,648
(The interest rate is fixed at a rate of 8.25%)		
	$ 2,950,452	$ 3,126,644

(1) These notes were redeemed February 1, 2022.

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, 2021. 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, 2021 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, 2021. 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
Senior Vice President and Chief Financial Officer

Fort Worth, Texas
February 22, 2022

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, 2021, 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, 2021, 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, 2021 and 2020, 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, 2021, and the related notes and our report dated February 22, 2022 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 22, 2022

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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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 22, 2022 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, 2021, the net book value of the Company's proved natural gas and oil properties totaled $4.9 billion and depletion, depreciation and amortization expense ("DD&A") was $365 million for the year then ended. As described in Note 2, proved natural gas and oil properties are accounted for under the successful efforts method of accounting. 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 natural gas and oil reserve estimates are based on geological and engineering evaluations of in-place hydrocarbon volumes. Significant judgment is required by the Company's petroleum engineering staff in evaluating geological and engineering data when estimating proved natural gas and oil reserves. Estimating reserves also requires the selection of inputs, including natural gas and oil price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating natural gas and oil reserves, management used independent petroleum consultants to audit approximately 97% of the proved reserve estimates prepared by the Company's petroleum engineering staff as of December 31, 2021. 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.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating proved natural gas and oil reserves. Our audit procedures included, among others, 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. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating proved natural gas and oil reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's drill plan and the availability of capital relative to the drill plan. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved natural gas and oil reserve amounts used to the Company's reserve report.

/s/ Ernst & Young LLP

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

Fort Worth, Texas
February 22, 2022

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

	December 31, 2021	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 214,422	$ 458
Accounts receivable, less allowance for doubtful accounts of $568 and $3,004	471,775	252,642
Contingent consideration receivable	29,500	—
Derivative assets	5,738	23,332
Prepaid and other current assets	15,230	13,408
Total current assets	736,665	289,840
Derivative assets	38,601	16,680
Natural gas and oil properties, successful efforts method	10,175,570	9,751,114
Accumulated depletion and depreciation	(4,420,914)	(4,064,305)
	5,754,656	5,686,809
Other property and equipment	74,678	79,878
Accumulated depreciation and amortization	(71,184)	(75,717)
	3,494	4,161
Operating lease right-of-use assets	40,832	63,581
Other assets	86,259	75,865
Total assets	$ 6,660,507	$ 6,136,936
Liabilities		
Current liabilities:		
Accounts payable	$ 178,413	$ 132,421
Asset retirement obligations	5,310	6,689
Accrued liabilities	420,898	348,333
Accrued interest	75,940	54,742
Derivative liabilities	162,767	26,707
Divestiture contract obligation	91,120	92,593
Current maturities of long-term debt	218,017	45,356
Total current liabilities	1,152,465	706,841
Bank debt	—	693,123
Senior notes	2,707,770	2,329,745
Senior subordinated notes	—	17,384
Deferred tax liabilities	117,642	135,267
Derivative liabilities	8,216	9,746
Deferred compensation liabilities	137,102	81,481
Operating lease liabilities	24,861	43,155
Asset retirement obligations and other liabilities	101,509	91,157
Divestiture contract obligation	325,279	391,502
Total liabilities	4,574,844	4,499,401
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, 259,795,554 issued at December 31, 2021 and 256,353,887 issued at December 31, 2020	2,598	2,563
Common stock held in treasury, at cost, 10,002,646 shares at December 31, 2021 and 10,005,795 shares at December 31, 2020	(30,007)	(30,132)
Additional paid-in capital	5,720,277	5,684,268
Accumulated other comprehensive loss	(150)	(479)
Retained deficit	(3,607,055)	(4,018,685)
Total stockholders' equity	2,085,663	1,637,535
Total liabilities and stockholders' equity	$ 6,660,507	$ 6,136,936

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,		
	2021	**2020**	**2019**
Revenues and other income:			
Natural gas, NGLs and oil sales	$ 3,215,027	$ 1,607,713	$ 2,255,425
Derivative fair value (loss) income	(650,216)	187,711	226,681
Brokered natural gas, marketing and other	365,412	173,273	345,509
Total revenues and other income	2,930,223	1,968,697	2,827,615
Costs and expenses:			
Direct operating	75,287	92,157	136,276
Transportation, gathering, processing and compression	1,174,469	1,088,490	1,199,297
Production and ad valorem taxes	29,317	24,617	37,967
Brokered natural gas and marketing	367,288	188,316	359,892
Exploration	23,555	32,654	36,683
Abandonment and impairment of unproved properties	7,206	19,334	1,235,342
General and administrative	169,766	159,415	181,109
Exit and termination costs	21,661	547,409	9,506
Deferred compensation plan	68,351	12,541	(15,472)
Interest	227,336	192,667	194,285
Loss (gain) on early extinguishment of debt	98	(14,068)	(5,415)
Depletion, depreciation and amortization	364,555	394,330	548,843
Impairment of proved properties and other assets	—	78,955	1,095,634
(Gain) loss on the sale of assets	(701)	(110,791)	30,256
Total costs and expenses	2,528,188	2,706,026	5,044,203
Income (loss) before income taxes	402,035	(737,329)	(2,216,588)
Income tax expense (benefit):			
Current	7,984	(523)	6,147
Deferred	(17,727)	(25,029)	(506,438)
	(9,743)	(25,552)	(500,291)
Net income (loss)	$ 411,778	$ (711,777)	$ (1,716,297)
Net income (loss) per common share:			
Basic	$ 1.65	$ (2.95)	$ (6.92)
Diluted	$ 1.61	$ (2.95)	$ (6.92)
Weighted average common shares outstanding:			
Basic	242,862	241,373	247,970
Diluted	249,314	241,373	247,970

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,		
	2021	**2020**	**2019**
Net income (loss)	$ 411,778	$ (711,777)	$ (1,716,297)
Other comprehensive loss:			
Postretirement benefits:			
Actuarial gain (loss)	62	39	(532)
Amortization of prior service costs	369	369	369
Income tax (expense) benefit	(102)	(99)	33
Total comprehensive income (loss)	$ 412,107	$ (711,468)	$ (1,716,427)

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, 2021	2020	2019
Operating activities:			
Net income (loss)	$ 411,778	$ (711,777)	$ (1,716,297)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:			
Deferred income tax benefit	(17,727)	(25,029)	(506,438)
Depletion, depreciation and amortization and impairment of proved properties	364,555	473,285	1,644,477
Exploration dry hole costs	—	888	(11)
Abandonment and impairment of unproved properties	7,206	19,334	1,235,342
Derivative fair value loss (income)	650,216	(187,711)	(226,681)
Cash settlements on derivative financial instruments	(520,013)	322,629	188,384
Divestiture contract obligation	20,340	499,934	—
Allowance for bad debt	200	400	4,341
Amortization of deferred financing costs and other	8,347	6,919	6,455
Deferred and stock-based compensation	110,356	48,552	24,891
(Gain) loss on the sale of assets	(701)	(110,791)	30,256
Gain on early extinguishment of debt	98	(14,068)	(5,415)
Changes in working capital:			
Accounts receivable	(250,538)	24,539	214,196
Prepaid and other	(1,140)	1,010	4,520
Accounts payable	39,231	(32,686)	(60,374)
Accrued liabilities and other	(29,260)	(46,748)	(155,803)
Net cash provided from operating activities	792,948	268,680	681,843
Investing activities:			
Additions to natural gas and oil properties	(393,478)	(405,617)	(687,277)
Additions to field service assets	(1,231)	(2,873)	(1,162)
Acreage purchases	(23,962)	(26,816)	(59,986)
Proceeds from disposal of assets	303	246,127	784,937
Purchases of marketable securities held by the deferred compensation plan	(30,806)	(17,076)	(19,039)
Proceeds from the sales of marketable securities held by the deferred compensation plan	31,295	22,173	22,005
Net cash (used in) provided from investing activities	(417,879)	(184,082)	39,478
Financing activities:			
Borrowings on credit facilities	1,434,000	2,076,000	2,311,000
Repayments on credit facilities	(2,136,000)	(1,851,000)	(2,777,000)
Issuance of senior notes	600,000	850,000	—
Repayment of senior or senior subordinated notes	(63,324)	(1,120,634)	(195,432)
Dividends paid	—	—	(20,070)
Treasury stock purchases	—	(22,992)	(6,908)
Debt issuance costs	(8,854)	(13,608)	(4,446)
Taxes paid for shares withheld	(9,299)	(3,324)	(3,384)
Change in cash overdrafts	16,493	176	(25,747)
Proceeds from the sales of common stock held by the deferred compensation plan	5,879	696	667
Net cash used in financing activities	(161,105)	(84,686)	(721,320)
Increase (decrease) in cash and cash equivalents	213,964	(88)	1
Cash and cash equivalents at beginning of year	458	546	545
Cash and cash equivalents at end of year	$ 214,422	$ 458	$ 546

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		Common stock held in	Additional paid-	Retained	Accumulated other comprehensive	
	Shares	Par value	treasury	in capital	(deficit)	loss	Total
Balance as of December 31, 2018	249,520	$ 2,495	$ (391)	$ 5,628,447	$ (1,570,462)	$ (658)	**$ 4,059,431**
Issuance of common stock	1,919	19	—	323	—	—	**342**
Issuance of common stock upon vesting of PSUs	—	—	—	5	(5)	—	**—**
Stock-based compensation expense	—	—	—	31,120	—	—	**31,120**
Cash dividends paid ($0.08 per share)	—	—	—	—	(20,070)	—	**(20,070)**
Treasury stock issuance	—	—	63	(63)	—	—	**—**
Treasury stock repurchased	—	—	(6,908)	—	—	—	**(6,908)**
Other comprehensive loss	—	—	—	—	—	(130)	**(130)**
Net loss	—	—	—	—	(1,716,297)	—	**(1,716,297)**
Balance as of December 31, 2019	251,439	2,514	(7,236)	5,659,832	(3,306,834)	(788)	**2,347,488**
Issuance of common stock	4,896	49	—	(942)	—	—	**(893)**
Issuance of common stock upon vesting of PSUs	19	—	—	74	(74)	—	—
Stock-based compensation expense	—	—	—	25,400	—	—	**25,400**
Treasury stock issuance	—	—	96	(96)	—	—	—
Treasury stock repurchased	—	—	(22,992)	—	—	—	**(22,992)**
Other comprehensive income	—	—	—	—	—	309	**309**
Net loss	—	—	—	—	(711,777)	—	**(711,777)**
Balance as of December 31, 2020	256,354	2,563	(30,132)	5,684,268	(4,018,685)	(479)	**1,637,535**
Issuance of common stock	3,429	35	—	6,998	—	—	**7,033**
Issuance of common stock upon vesting of PSUs	13	—	—	148	(148)	—	—
Stock-based compensation expense	—	—	—	28,988	—	—	**28,988**
Treasury stock issuance	—	—	125	(125)	—	—	—
Other comprehensive income	—	—	—	—	—	329	**329**
Net income	—	—	—	—	411,778	—	**411,778**
Balance as of December 31, 2021	**259,796**	**$ 2,598**	**$ (30,007)**	**$ 5,720,277**	**$ (3,607,055)**	**$ (150)**	**$ 2,085,663**

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 primarily 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 and oil 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.

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, asset retirement obligations, 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 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 certain 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 income of $1.1 million in 2021 compared to a loss of $14.2 million in both 2020 and 2019.

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 $568,000 at December 31, 2021 compared to $3.0 million at December 31, 2020. We recorded debt expense of $200,000 in the year ended December 31, 2021 compared to $400,000 in the year ended December 31, 2020 and $4.3 million in the year ended December 31, 2019.

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 annually and periodically as events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. 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. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop reserves. Expected future net cash inflow from the sale of produced reserves is calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market-related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable and possible reserves, as appropriate, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climate. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of cash flows. When the carrying value exceeds the sum of undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value as determined by discounted future net cash flows using a discount rate similar to that used by market participants, or comparable market value if available and the carrying value of the asset. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas and oil prices, an estimate of the ultimate amount of recoverable natural gas and oil reserves that will be produced from an asset group, the timing of future production, future production costs, future abandonment costs and future inflation. We cannot predict whether impairment charges may be required in the future. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments. For additional information regarding proved property impairments, see Note 10.

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. In certain circumstances, our future plans to develop acreage may accelerate our impairment. Unproved properties had a net book value of $837.3 million as of December 31, 2021 compared to $859.8 million in 2020. We have recorded abandonment and impairment expense related to unproved properties of $7.2 million in the year ended December 31, 2021 compared to $19.3 million in 2020 and $1.2 billion in 2019. In 2019, an impairment of $1.2 billion was recorded associated with our North Louisiana unproved property values that we no longer had the intent to drill based on a shift in capital allocation.

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 $2.4 million in the year ended December 31, 2021 compared to $2.6 million in the year ended December 31, 2020 and $5.0 million in the year ended December 31, 2019.

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, 2021 include $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. Other assets at December 31, 2020 included $63.9 million of marketable securities held in our deferred compensation plans and $11.9 million of other investments.

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. We have entered into propane basis swaps which lock in the differential between Mont Belvieu and international propane indexes. We have also entered into combined natural gas derivative instruments containing a fixed price swap and a sold option to extend the term or expand the volume (which we refer to as a swaption). The swap price is a fixed price determined at the time of the swaption contract. If the option is exercised, the contract will become a swap treated consistently with our fixed-price swaps. 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. During 2021, we did not materially modify any existing derivative contracts.

Concentrations of Credit Risk

As of December 31, 2021, 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, 2021, we had one customer that accounted for 10% or more of natural gas, NGLs and oil sales compared to 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, 2021, our derivative counterparties included fifteen financial institutions and commodity traders, of which all but five are secured lenders in our bank credit facility. At December 31, 2021, our net derivative liability includes a payable to one counterparty not included in our bank credit facility totaling $637,000 and a receivable from the remaining four counterparties of $4.9 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 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 facilities 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 and federal and state regulatory requirements. 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 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 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 $701,000 in the year ended December 31, 2021 compared to a pretax gain of $110.8 million in 2020 and a pretax loss of $30.3 million in 2019. The following describes the significant divestitures that are included in our consolidated results of operations for each of three years ended December 31, 2021, 2020 and 2019.

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 current and 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 sheet 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.

2019 Dispositions

Pennsylvania. In third quarter 2019, we sold, in three separate transactions, a proportionately reduced 2.5% overriding royalty, primarily in our Washington County, Pennsylvania leases for gross proceeds of $750.0 million. We recorded a pretax loss of $36.5 million related to this sale which represents closing adjustments and transaction fees. In second quarter 2019, we sold natural gas and oil property, primarily representing over 20,000 unproved acres, for proceeds of $34.0 million and recognized a pretax gain of $5.9 million.

(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,		
	2021	2020	2019
Natural gas sales	$ 1,896,231	$ 943,740	$ 1,388,838
NGLs sales	1,135,826	578,454	681,134
Oil and condensate sales	182,970	85,519	185,453
Total natural gas, NGLs and oil sales	3,215,027	1,607,713	2,255,425
Sales of purchased natural gas	342,431	160,122	332,006
Sales of purchased NGLs	6,925	3,776	1,661
Other marketing revenue	16,056	9,375	11,842
Total	$ 3,580,439	$ 1,780,986	$ 2,600,934

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, 2021, 2020 and 2019, 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 $460.2 million at December 31, 2021 compared to $237.8 million at December 31, 2020.

(5) Income Taxes

Our income tax benefit was $9.7 million for the year ended December 31, 2021 compared to $25.6 million in 2020 and $500.3 million in 2019. Reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2021	2020	2019
Federal statutory tax rate	21.0%	21.0%	21.0%
State, net of federal benefit	4.0	5.2	3.8
State rate and law change	(3.4)	4.3	1.8
Valuation allowances	(24.8)	(26.3)	(3.8)
Non-deductible equity compensation	0.8	(0.7)	(0.2)
Consolidated effective tax rate	(2.4%)	3.5%	22.6%

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

	2021			2020			2019		
	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
U.S. federal	$ —	$ 6,297	$ 6,297	$ (366)	$ (24,489)	$ (24,855)	$ —	$ (434,585)	$ (434,585)
U.S. state and local	7,984	(24,024)	(16,040)	(157)	(540)	(697)	6,147	(71,853)	(65,706)
Total	$ 7,984	$ (17,727)	$ (9,743)	$ (523)	$ (25,029)	$ (25,552)	$ 6,147	$ (506,438)	$ (500,291)

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

	December 31, 2021	December 31, 2020
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforward	$ 788,375	$ 879,339
Divestiture contract obligation	112,199	132,352
Deferred compensation	22,121	16,635
Equity compensation	4,833	5,445
Asset retirement obligations	21,734	18,923
Interest expense carryforward	53,876	15,757
Lease right-of-use assets	9,954	16,070
Cumulative mark-to-market loss	32,221	2,607
Other	12,181	12,082
Valuation allowances:		
Federal	(67,984)	(152,499)
State, net of federal benefit	(203,085)	(226,520)
Total deferred tax assets	786,425	720,191
Deferred tax liabilities:		
Depreciation and depletion	(879,163)	(835,506)
Operating lease liabilities	(9,247)	(15,058)
Other	(15,657)	(4,894)
Total deferred tax liabilities	(904,067)	(855,458)
Net deferred tax liability	$ (117,642)	$ (135,267)

At December 31, 2021, deferred tax liabilities exceeded deferred tax assets by $117.6 million. As of December 31, 2021, we have a state valuation allowance of $203.1 million related to state tax attributes in Louisiana, Oklahoma, Pennsylvania, Texas and West Virginia. As of December 31, 2021, we have federal valuation allowances of $68.0 million primarily related to our federal net operating loss carryforward ("NOL"), and federal basis differences. The net change in our deferred tax asset valuation allowances was a reduction of $108.0 million for the year ended December 31, 2021 compared to an increase in our valuation allowances of $188.2 million in 2020 and an increase of $70.5 million in 2019.

At December 31, 2021, we had federal NOL carryforwards of $2.9 billion. This includes $1.2 billion that expires between 2030 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 $861.0 million that expire between 2028 and 2040 and in Louisiana, we have state NOL carryforwards of $1.5 billion that do not expire. We file consolidated tax returns 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 2017 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 accrued interest or penalties related to tax amounts as of December 31, 2021. Throughout 2021, 2020 and 2019, our unrecognized tax benefits were not material.

(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,		
	2021	2020	2019
Net income (loss), as reported	$ 411,778	$ (711,777)	$ (1,716,297)
Participating basic earnings [a]	(10,795)	—	(251)
Basic net income (loss) attributed to common stockholders	400,983	(711,777)	(1,716,548)
Reallocation of participating earnings [a]	272	—	—
Diluted net income (loss) attributed to common stockholders	$ 401,255	$ (711,777)	$ (1,716,548)
Net income (loss) per common share:			
Basic	$ 1.65	$ (2.95)	$ (6.92)
Diluted	$ 1.61	$ (2.95)	$ (6.92)

[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,		
	2021	2020	2019
Denominator:			
Weighted average common shares outstanding – basic	242,862	241,373	247,970
Effect of dilutive securities	6,452	—	—
Weighted average common shares outstanding – diluted	249,314	241,373	247,970

Weighted average common shares outstanding – basic excludes 6.5 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, 2021 compared to 5.5 million shares for the period ending December 31, 2020 and 3.1 million shares for the period ending December 31, 2019. Due to our net loss for the years ended December 31, 2020 and 2019, 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 18,000 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. For December 31, 2021, deferred financing costs for our bank credit facility are included in other assets in the accompanying consolidated balance sheet. 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. No interest was capitalized in the three-year period ended December 31, 2021. The components of our debt outstanding, including the effects of debt issuance costs, is as follows (in thousands):

	December 31, 2021	December 31, 2020
Bank debt	$ —	$ 702,000
Senior notes		
4.875% senior notes due 2025	750,000	750,000
5.00% senior notes due 2022	169,589	169,589
5.00% senior notes due 2023	532,335	532,335
5.75% senior notes due 2021	—	25,496
5.875% senior notes due 2022	48,528	48,528
8.25% senior notes due 2029	600,000	—
9.25% senior notes due 2026	850,000	850,000
Other senior notes due 2022	—	490
Total senior notes	2,950,452	2,376,438
Senior subordinated notes		
5.00% senior subordinated notes due 2022	—	9,730
5.00% senior subordinated notes due 2023	—	7,712
5.75% senior subordinated notes due 2021	—	19,896
Total senior subordinated notes	—	37,338
Total debt	2,950,452	3,115,776
Unamortized premium	188	457
Unamortized debt issuance costs	(24,853)	(30,625)
Total debt (net of debt issuance costs)	2,925,787	3,085,608
Less current maturities of long-term debt	(218,017)	(45,356)
Total long-term debt	$ 2,707,770	$ 3,040,252

Bank Debt

In April 2018, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets and has a maturity date of April 13, 2023. 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 twenty-six financial institutions, with no one bank holding more than 8.3% of the total facility. 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 LIBOR Rate (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 LIBOR loans to ABR loans or to convert all or any part of our ABR loans to LIBOR loans. The weighted average interest rate was 2.1% for the year ended December 31, 2021 compared to 2.6% for the year ended December 31, 2020 and 3.8% for the year ended December 31, 2019. A commitment fee is paid on the undrawn balance based on an annual rate of 0.30% to 0.375%. At December 31, 2021, the commitment fee was 0.3%, the interest rate margin was 1.75% on our LIBOR loans and 0.75% on our ABR loans.

On December 31, 2021, bank commitments totaled $2.4 billion and we had no outstanding borrowings under our bank credit facility. Additionally, we had $338.0 million of undrawn letters of credit leaving $2.1 billion of committed borrowing capacity available under the facility. As part of our redetermination completed in September 2021, our borrowing base was reaffirmed for $3.0 billion and our bank commitment was also reaffirmed at $2.4 billion. As of February 18, 2022, we have sufficient available borrowing capacity under our credit facility to satisfy any requests for additional collateral our transportation counterparties may request in the event of a credit rating downgrade.

New Senior Notes

In January 2021, we issued $600.0 million aggregate principal amount of 8.25% senior notes due 2029 (the “8.25% Notes”) for an estimated net proceeds of $591.3 million after underwriting discounts and commissions of $8.8 million. The notes were issued at par. The 8.25% Notes were offered to qualified institutional buyers and to non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act of 1933, as amended (the “Securities Act”). Interest due on the 8.25% Notes is payable semi-annually in January and July and is unconditionally guaranteed on a senior unsecured basis by all of our subsidiary guarantors. On or after January 15, 2027, we may redeem the 8.25% Notes in whole or in part 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 8.25% Notes. Upon occurrence of certain changes in control, we must offer to repurchase the 8.25% Notes. The 8.25% 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. Upon closing of the 8.25% Notes, we used the proceeds to repay borrowings under our bank credit facility. In October 2021, our 8.25% Notes were exchanged for an equal principal amount of registered notes pursuant to an effective registration statement on Form S-4 filed with the SEC on October 28, 2021 under the Securities Act (the "New Notes"). The New Notes are identical to the 8.25% Notes except the New Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest.

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 $492.1 million after underwriting discounts and commissions of $7.9 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 ending December 31, 2022, we currently expect to record a loss of early extinguishment of debt of approximately $70.0 million, including transaction call premium costs and the expensing of the remaining deferred financing costs on the repurchased debt.

Senior Notes

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. All of the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and are subordinated to existing and future senior debt that we or our subsidiary guarantors are permitted to incur.

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. 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. In addition, we are required to maintain a ratio of EBITDAX (as defined in the credit agreement) to cash interest expense of equal to or greater than 2.5 and a current ratio (as defined in the credit agreement) of no less than 1.0. In addition, the ratio of the present value of proved reserves (as defined in the credit agreement) to total debt must be equal to or greater than 1.5 until Range has two investment grade ratings. We were in compliance with applicable covenants under the bank credit facility at December 31, 2021. Certain of our senior notes may also limit our ability to pay cash dividends.

The following is the principal maturity schedule for our long-term debt outstanding as of December 31, 2021 (in thousands):

	Year Ended December 31,
2022	$ 218,117
2023	532,335
2024	—
2025	750,000
2026	850,000
Thereafter	600,000
	$ 2,950,452

(8) Asset Retirement Obligations

Our asset retirement obligations ("ARO") primarily represent 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, 2021 and 2020 (in thousands):

	2021	2020
Beginning of period	$ 79,822	$ 251,076
Liabilities incurred	73	1,483
Acquisitions	—	123
Liabilities settled	(8,197)	(4,634)
Disposition of wells	—	(176,748)
Accretion expense	5,511	7,518
Change in estimate	18,627	1,004
End of period	95,836	79,822
Less current portion	(5,310)	(6,689)
Long-term asset retirement obligations	$ 90,526	$ 73,133

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 swap, calls, swaptions 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 or Mont Belvieu for NGLs), approximated a net derivative liability of $169.5 million at December 31, 2021. These contracts expire monthly through December 2023. The following table sets forth the derivative volumes by year as of December 31, 2021, excluding our basis, freight swaps 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 [(1)]						
2022	Swaps	497,479 Mmbtu/day	$ 3.12			
2022	Collars	224,301 Mmbtu/day			$ 3.28	$ 3.73
2022	Three-way Collars	251,781 Mmbtu/day		$ 2.37	$ 3.03	$ 3.77
January-March 2022	Calls	80,000 Mmbtu/day				$ 6.02
2023	Swaps	197,500 Mmbtu/day	$ 3.40			
2023	Collars	110,000 Mmbtu/day			$ 3.26	$ 4.26
2023	Three-way Collars	70,000 Mmbtu/day		$ 2.25	$ 3.25	$ 4.28
Crude Oil						
2022	Swaps	6,437 bbls/day	$ 60.73			
2023	Swaps	623 bbls/day	$ 66.40			
NGLs (C5-Natural Gasoline)						
January-June 2022	Swaps	2,749 bbls/day	$1.65/gallon			
January-June 2022	Collars	1,497 bbls/day			$1.53/gallon	$1.67/gallon

(1) We also sold natural gas call swaptions of 72,500 Mmbtu/day for 2023 at a weighted average price of $3.06 per Mmbtu.

Basis Swap Contracts

In addition to the swaps, collars and swaptions above, at December 31, 2021, 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 2024 and include a total volume of 213,710,000 Mmbtu. The fair value of these contracts was a net derivative asset of $16.0 million on December 31, 2021.

At December 31, 2021, we also had propane spread swap contracts which lock in the differential between Mont Belvieu and international propane indexes. The contracts settle monthly in first quarter 2022. The fair value of these contracts was a net derivative asset of $123,000 on December 31, 2021.

Freight Swap Contracts

In connection with our international propane sales, we utilize propane swaps. To further hedge our propane price, at December 31, 2021, we had freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange. These contracts settle monthly and cover 7,000 metric tons for first quarter 2022. The fair value of these contracts was a net derivative asset of $114,000 on December 31, 2021.

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 $45.5 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 years 2022 and 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, 2021 was a derivative asset of $26.6 million. In addition, we currently expect to receive $29.5 million for the year ended December 31, 2021 which is reflected in current assets in the accompanying consolidated balance sheet and represents the maximum contingent payment amount for 2021.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of December 31, 2021 and 2020 is summarized below (in thousands). As of December 31, 2021, we are conducting derivative activities with fifteen counterparties, of which all but five 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, 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)

		December 31, 2020		
		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	$ 33,559	$ (16,821)	$ 16,738
	–collars	7,016	(2,329)	4,687
	–three-way collars	535	(6,139)	(5,604)
	–basis swaps	7,894	(3,502)	4,392
Crude oil	–swaps	2,465	(829)	1,636
NGLs	–C3 propane spread	4,863	(4,863)	—
	–C3 propane collars	—	(107)	(107)
Freight	–swaps	2,310	—	2,310
Divestiture contingent consideration		15,960	—	15,960
		$ 74,602	$ (34,590)	$ 40,012

		December 31, 2020		
		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	$ (10,120)	$ 16,821	$ 6,701
	–swaptions	(9,803)	—	(9,803)
	–collars	—	2,329	2,329
	–three-way collars	(18,353)	6,139	(12,214)
	–basis swaps	(4,197)	3,502	(695)
Crude oil	–swaps	(5,471)	829	(4,642)
NGLs	–C3 propane spread	(4,069)	4,863	794
	–C3 propane swaps	(8,243)	—	(8,243)
	–C3 propane collars	(3,086)	107	(2,979)
	–C5 natural gasoline swaps	(4,897)	—	(4,897)
	–C5 natural gasoline calls	(546)	—	(546)
	–NC4 butane swaps	(651)	—	(651)
	–NC4 butane collars	(401)	—	(401)
Freight	–swaps	(1,206)	—	(1,206)
		$ (71,043)	$ 34,590	$ (36,453)

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,		
	2021	2020	2019
Commodity swaps	$ (466,203)	$ 158,248	$ 219,968
Swaptions	(1,346)	(4,955)	333
Collars	(117,612)	3,304	(3,903)
Three-way collars	(137,443)	(16,346)	—
Basis swaps	33,691	48,278	6,661
Calls	(836)	(558)	(349)
Freight swaps	(647)	(1,230)	3,971
Divestiture contingent consideration	40,180	970	—
Total	$ (650,216)	$ 187,711	$ 226,681

(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, 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

		Fair Value Measurements at December 31, 2020 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, 2020
Trading securities held in the deferred compensation plans		$ 63,942	$ —	$ —	$ 63,942
Derivatives	–swaps	—	6,642	—	6,642
	–calls	—	—	(546)	(546)
	–collars	—	7,016	(3,487)	3,529
	–three-way collars	—	(17,818)	—	(17,818)
	–basis swaps	—	4,491	—	4,491
	–swaptions	—	—	(9,803)	(9,803)
Derivatives	–freight swaps	—	1,104	—	1,104
Divestiture contingent consideration		—	15,960	—	15,960

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2021 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. As of December 31, 2021, a portion of our natural gas derivative instruments contain swaptions where the counterparty has the right, but not the obligation, to enter into a fixed price swap on a predetermined date. In addition to our swaptions in Level 3, at December 31, 2021, we have NGLs collars. Subjectivity in the volatility factors utilized can cause a significant change in the fair value measurement of our derivatives in Level 3. For our natural gas swaptions, we used a weighted average implied volatility of 25%. We utilized a range of implied volatilities from 37% to 61% for our NGLs collars with a weighted average implied volatility of approximately 45%. 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, 2021
Balance at December 31, 2020	$ (13,836)
Additions	(12,420)
Settlements	5,176
Transfers out of Level 3	8,660
Balance at December 31, 2021	$ (12,420)

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, 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. For the year ended December 31, 2019, interest and dividends were $1.1 million and mark-to-market was a gain of $8.5 million.

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 used 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.

Fair Values-Non recurring

In fourth quarter 2019, there were indicators that the carrying value of our North Louisiana properties may be impaired due to a shift in business strategy employed by management and also the possibility of a divestiture of these assets. As a result of the impairment evaluation, where we used an income approach, also referred to as a discounted cash flow model, to assess fair value, we recorded an impairment of $1.1 billion. An additional guideline transaction market approach was also utilized to corroborate the estimated fair value. In first quarter 2020, we recognized an additional impairment charge of $77.0 million related to these North Louisiana properties that reduced the carrying value to the anticipated sales proceeds which is a market approach using Level 2 inputs.

See also Note 3 for additional information. The following table presents the value of these assets measured at fair value on a nonrecurring basis at the time impairment was recorded (in thousands):

	Year Ended December 31,					
	2021		2020		2019	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Natural gas and oil properties	$ —	$ —	$ 290,500	$ 77,000	$ 370,500	$ 1,093,531

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. In fourth quarter 2019, we announced the closing of our Houston office. We recorded an impairment related to our Houston office lease ROU asset of $2.1 million which is also included in impairment of proved property and other assets for the year ended December 31, 2019.

Fair Values-Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of December 31, 2021 and 2020 (in thousands):

	December 31, 2021		December 31, 2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars, calls and basis swaps	$ 17,699	$ 17,699	$ 24,052	$ 24,052
Divestiture contingent consideration	26,640	26,640	15,960	15,960
Marketable securities [(a)]	69,606	69,606	63,942	63,942
(Liabilities):				
Commodity swaps, collars, calls and basis swaps	(170,983)	(170,983)	(36,453)	(36,453)
Bank credit facility [(b)]	—	—	(702,000)	(702,000)
5.75% senior notes due 2021 [(b)]	—	—	(25,496)	(25,474)
5.00% senior notes due 2022 [(b)]	(169,589)	(171,488)	(169,589)	(170,128)
5.875% senior notes due 2022 [(b)]	(48,528)	(48,955)	(48,528)	(48,471)
Other senior notes due 2022 [(b)]	—	—	(490)	(490)
5.00% senior notes due 2023 [(b)]	(532,335)	(543,471)	(532,335)	(521,699)
4.875% senior notes due 2025 [(b)]	(750,000)	(776,153)	(750,000)	(707,918)
9.25% senior notes due 2026 [(b)]	(850,000)	(916,929)	(850,000)	(888,208)
8.25% senior notes due 2029 [(b)]	(600,000)	(669,648)	—	—
5.75% senior subordinated notes due 2021 [(b)]	—	—	(19,896)	(19,589)
5.00% senior subordinated notes due 2022 [(b)]	—	—	(9,730)	(9,247)
5.00% senior subordinated notes due 2023 [(b)]	—	—	(7,712)	(6,604)
Deferred compensation plan [(c)]	(165,395)	(165,395)	(96,563)	(96,563)

(a) Marketable securities, which are held in our deferred compensation plans, are actively traded on major exchanges and is 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 and our senior subordinated 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, 2021 (in thousands):

	2021	2020	2019
Direct operating expense	$ 1,310	$ 1,078	$ 1,928
Brokered natural gas and marketing expense	1,794	1,416	1,856
Exploration expense	1,507	1,279	1,566
General and administrative expense	39,673	32,905	35,061
Termination costs	—	2,165	1,971
Total stock-based compensation	$ 44,284	$ 38,843	$ 42,382

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 plans 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 2021, we recorded an additional tax benefit of an estimated $340,000 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 expense of $4.3 million in 2020 and additional tax expense of $3.4 million in 2019.

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. 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 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.

At grant date, each unit represents the value of one share of our common stock. These units are settled in stock and the amount of the payout is based on (1) the vesting percentage, which can be from zero to 200% based on the performance achieved and (2) the value of our common stock on the date payout is determined by the compensation committee. Dividend equivalents may accrue during the performance period and would be paid in stock at the end of the performance period. The performance period is three years.

Restricted Stock – Equity Awards

In 2021, we granted 2.3 million restricted stock Equity Awards to employees which generally vest over a three-year period compared to 4.5 million in 2020 and 2.8 million in 2019. We recorded compensation expense for these awards of $19.6 million in the year ended December 31, 2021 compared to $17.8 million in 2020 and $22.5 million in 2019. As of December 31, 2021, there was $19.0 million of unrecognized compensation related to Equity Awards expected to be recognized over a weighted average period of 1.8 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 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. These grants included 102,000 shares issued to non-employee directors, which vest at the end of one year and 1.2 million shares to employees with vesting generally over 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. This grant 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. In 2019, we granted 1.2 million shares of restricted stock Liability Awards as compensation to directors and employees at an average grant date fair value of $10.16. These grants included 183,000 shares issued to non-employee directors, which vested immediately and 1.0 million shares to employees with vesting generally over a three-year period. We recorded compensation expense for these restricted stock Liability Awards of $11.4 million in the year ended December 31, 2021 compared to $10.3 million in 2020 and $9.3 million in 2019. As of December 31, 2021, there was $4.4 million of unrecognized compensation related to restricted stock Liability Awards expected to be recognized over a weighted average period of 1.4 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 $5.9 million in 2021 compared to $696,000 in 2020 and $667,000 in 2019. The following is a summary of the status of our non-vested restricted stock outstanding at December 31, 2021:

	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, 2020	2,815,860	$ 4.97	1,186,636	$ 4.18
Granted	2,340,114	10.20	1,289,495	9.56
Vested	(2,397,336)	7.33	(1,679,502)	7.21
Forfeited	(83,861)	6.32	—	—
Outstanding at December 31, 2021	2,674,777	$ 7.39	796,629	$ 6.49

Stock-Based Performance Units

Internal Performance Metric Awards. Awards granted in 2019 and 2020 were earned based on:

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

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

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

Prior to 2021, the performance period was based on annual performance targets earned over a three-year period. For awards granted in 2021, the three-year target was set in first quarter 2021. 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, 2021:

	Number of Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2020	1,099,102	$ 5.92
Units granted [(a)]	303,231	9.81
Vested	(306,978)	12.20
Forfeited [(b)]	—	—
Outstanding at December 31, 2021	1,095,355	$ 7.80

(a) Amounts granted reflect the number of performance units granted; however, the actual payout of shares will be between zero and 200% depending on achievement of specifically identified performance targets.

(b) For Production Growth units granted in 2019 which are set to vest in early 2022, the payout is estimated at 74%. For Reserve Growth units granted in 2019 which are set to vest in early 2022, the payout is estimated at 121%.

We recorded internal performance metric award compensation expense of $6.6 million in the year ended December 31, 2021 compared to $2.7 million in the year ended December 31, 2020 and $3.8 million in the year ended December 31, 2019. As of December 31, 2021, there was $2.6 million of unrecognized compensation related to these internal performance metric awards to be recognized over a weighted average period of 1.4 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. 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, 2021, 2020 and 2019:

	Year Ended December 31,		
	2021	2020	2019
Risk-free interest rate	0.2%	1.4%	2.4%
Expected annual volatility	75%	65%	46%
Grant date fair value per unit	$ 12.58	$ 3.85	$ 11.34

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, 2020	1,249,524	$ 9.55
Granted [(a)]	223,687	12.58
Vested and issued [(b)]	(325,217)	18.51
Forfeited	—	—
Outstanding at December 31, 2021	1,147,994	$ 7.60

(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-PSUs awards issued related to the 2018 performance period where the return on our common stock was negative and therefore, the performances multiple and actual payout was reduced to 100%.

We recorded TSR award compensation expense of $2.6 million in the year ended December 31, 2021 compared to $2.4 million in the year ended December 31, 2020 and $3.0 million in the year ended December 31, 2019. As of December 31, 2021, there was $1.5 million of unrecognized compensation related to these TSR awards to be recognized over a weighted average period of 1.5 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 2021, we contributed $4.6 million to the 401(k) Plan compared to $5.3 million in 2020 and $5.4 million in 2019. 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 over 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 $68.4 million in 2021 compared to a loss of $12.5 million in 2020 and a gain of $15.5 million in 2019. The Rabbi Trust held 6.2 million shares (5.4 million of vested shares) of Range stock at December 31, 2021 compared to 6.1 million (5.0 million of vested shares) at December 31, 2020.

Other Post-Retirement Benefits

We have a post retirement benefit plan to assist in providing health care to officers who are active employees (including their spouses) and have met certain age and service requirements. These benefits are not funded in advance and are provided up to age 65 or on the date they become eligible for Medicare, subject to various cost-sharing features. The change in our post-retirement benefit obligation is as follows (in thousands):

Change in Benefit Obligation:	2021	2020
Benefit obligation at beginning of year	$ 1,953	$ 1,957
Service cost	77	80
Interest cost	38	50
Actuarial (gain) loss	(62)	(39)
Benefits paid	(88)	(95)
Benefit obligation at end of year	$ 1,918	$ 1,953
Amounts recognized in the consolidated balance sheet:		
Long-term liabilities	$ 1,918	$ 1,953
Components of Net Periodic Post Retirement Benefit Cost:		
Service cost	$ 77	$ 80
Interest cost	38	50
Amortization of prior service cost	369	369
Net periodic post retirement costs (recognized in general and administrative expense)	$ 484	$ 499
Other Changes in Benefit Obligations in Other Comprehensive Income (Loss):		
Net (gain) loss	$ (62)	$ (39)
Prior service cost	—	—
Amortization of prior service cost	(369)	(369)
Total recognized in other comprehensive (loss) income	$ (431)	$ (408)
Total recognized in net periodic benefit cost and other comprehensive income	$ 53	$ 91

The following summarizes the assumptions used to determine the benefit obligation at December 31, 2021 and 2020:

	December 31, 2021	December 31, 2020
Weighted average assumptions used to determine benefit obligation:		
Discount rate	2.5%	1.9%
Assumed weighted average healthcare cost trend rates:		
Initial healthcare trend rate	7.0%	6.5%
Ultimate trend rate	4.0%	4.5%
Year ultimate trend rate reached	2033	2024

The expected future benefit payments under our post-retirement benefit plan is $768,000 for the five year period 2022 through 2026 and $458,000 for the five year period 2027 through 2031. The estimated prior service cost that will be amortized from accumulated other comprehensive loss into our statements of operations in 2022 is $369,000.

(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 2020:

	Year Ended December 31,	
	2021	2020
Beginning balance	246,348,092	249,630,803
Restricted stock grants	1,293,892	3,390,358
Restricted stock units vested	1,493,341	1,226,473
Performance stock units issued	640,468	279,420
Performance stock dividends	13,966	18,700
Treasury shares	3,149	(8,197,662)
Ending balance	249,792,908	246,348,092

Common Stock Dividends

The board of directors declared quarterly dividends of $0.02 per common share for each of the four quarters of 2019. In January 2020, we announced that the board had suspended the dividend. We expect the quarterly cash dividend will be reinstated in the second half of 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 of directors deem 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 approved an increase to this stock purchase plan where the board of directors authorized an additional repurchase of up to $500.0 million. The following is a schedule of the change in treasury shares since the beginning of 2020:

	Year Ended December 31,	
	2021	2020
Beginning balance	10,005,795	1,808,133
Rabbi trust shares distributed and/or sold	(3,149)	(2,338)
Shares repurchased	—	8,200,000
Ending balance	10,002,646	10,005,795

(13) Supplemental Cash Flow Information

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Net cash provided from operating activities included:			
Income taxes paid to taxing authorities	$ 7,061	$ 343	$ —
Interest paid	(196,750)	(168,471)	(189,443)
Non-cash investing and financing activities included:			
Asset retirement costs capitalized, net	$ 18,634	$ 2,610	$ 11,193
Decrease in accrued capital expenditures	(4,505)	(23,625)	(20,104)

(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, 2021 and 2020, liabilities for remediation were not material. We are not aware of any environmental claims existing as of December 31, 2021 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.

On March 4, 2021 a putative class action lawsuit was filed in the Western District of Pennsylvania in Case No. 2:21-CV-301 (Jacobowitz v. Range Resources Corporation et al.) in which the Plaintiff seeks to represent a class of Range stockholders who purchased or acquired stock from April 29, 2016 to February 10, 2021. This lawsuit was transferred to the U.S. District Court for the Northern District of Texas (Fort Worth Division). The lawsuit claims that Range misclassified certain wells as inactive rather than having plugged the wells and that such alleged misclassification affected the determination of our asset retirement obligation accrual. The lawsuit claims that the disclosure of a $294,000 agreed penalty that we paid to the Pennsylvania Department of Environmental Protection (DEP) in connection with the DEP's investigation of our application for inactive status for a small number of our wells, which the DEP disclosed during market hours on February 10, 2021 was the basis for the Plaintiffs' discovery of the alleged misrepresentations. We maintain that the factual allegations and the claims made in the litigation are baseless; there were no misrepresentations made and our asset retirement obligation was properly calculated. We also maintain that the market fully absorbed the information disclosed by the DEP on February 10, 2021 and the stock price on that day did not decrease. Given our view of the litigation as baseless, we are vigorously defending the litigation and moved for its dismissal. Additionally, on January 20, 2022, a derivative action styled as Lewis v. Ventura et al. was filed under seal in the Northern District of Texas (Case No. 4-22CV-051-0) asserting similar allegations as the previously described Jacobowitz matter. We maintain the same views as to the merits of the Lewis matter as the Jacobowitz matter as more fully detailed above and we plan to vigorously defend the matter.

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, 2021, the majority of which is included in general and administrative expense, are as follows (in thousands):

	Year Ended December 31,	
	2021	2020
Operating lease cost	$ 26,343	$ 27,895
Variable lease expense (1)	27,243	33,849
Short-term lease expense (2)	1,950	1,866
Sublease income	(2,380)	(3,199)
Total lease expense	$ 53,156	$ 60,411
Short-term lease costs (3)	$ 18,984	$ 15,984

(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 sheet.

(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,	
	2021	2020
Cash paid for amounts included in the measurement of lease liabilities	$ 28,118	$ 32,030
ROU assets added in exchange for lease obligations	$ 1,059	$ 27,769

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

	Year Ended December 31,	
	2021	2020
Operating lease ROU assets	$ 40,832	$ 63,581
Accrued liabilities – current	$ (19,066)	$ (24,673)
Operating lease liabilities – long-term	$ (24,861)	$ (43,155)

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

	Year Ended December 31,	
	2021	2020
Weighted average remaining lease term	3.8 years	4.0 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
2022	$ 21,281
2023	7,207
2024	6,546
2025	6,468
2026	6,168
Thereafter	2,627
Total lease payments	50,297
Less effects of discounting	(6,370)
Total lease liability	$ 43,927

We recorded impairment expense on certain office leases of $2.0 million in the year ended December 31, 2020 and $2.1 million in the year ended December 31, 2019.

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, process 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, 2021, future minimum transportation, processing and gathering fees under our commitments are as follows (in thousands):

	Transportation, Gathering and Processing Contracts [(a)]
2022	$ 801,974
2023	784,712
2024	768,059
2025	682,050
2026	623,561
Thereafter	3,520,105
	$ 7,180,461

(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 25,000 mcf per day and is expected to begin in 2022 with a six-year term.

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 and Note 10. As of December 31, 2021, the carrying value of this obligation was $416.4 million and is included in divestiture contract obligation in our consolidated balance sheet. As of December 31, 2021, our estimated settlement of this retained obligation based on a discounted value is as follows (in thousands):

	Divestiture Contract Obligation
2022	$ 91,120
2023	71,277
2024	58,401
2025	51,688
2026	36,971
Thereafter	106,942
	$ 416,399

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, 2021, our delivery commitments through 2031 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2022	588,158	55,000
2023	500,710	39,932
2024	253,566	35,000
2025	182,493	35,000
2026	158,301	35,000
2027	100,000	35,000
2028	100,000	35,000
2029	100,000	20,000
2030	—	20,000
2031	—	20,000

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 3,000 bbls per day starting in 2022 and increasing to 18,000 bbls per day in 2027 and increasing again to 25,000 bbls per day in 2029 then declining to 10,000 bbls per day in 2034 and declining again to 3,000 bbls per day through the end of the term in 2037.

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 and Termination 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 sheet. In the twelve months ended December 31, 2021, we recorded accretion expense of $47.9 million compared to $20.2 million in the prior year. In second quarter 2021, we also 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. In third quarter 2020, the present value of our estimated obligations related to these assets was initially recorded 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 $416.4 million at December 31, 2021.

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, 2021 was $7.3 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. In 2019, we sold various non-core assets in Pennsylvania and accrued $819,000 of severance costs related to this sale. In second quarter 2019, we also announced another reduction in our work force and recorded $2.2 million of severance costs related to this work force reduction. The following summarizes our exit and termination costs for the three years ended December 31, 2021, 2020 and 2019 (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Severance costs	$ 567	$ 5,909	$ 7,535
Transportation contract capacity releases (including accretion of discount)	754	10,900	—
Divestiture contract obligation (including accretion of discount)	20,340	499,935	—
One-time minimum volume commitment contract payment	—	28,500	—
Stock-based compensation and other	—	2,165	1,971
	$ 21,661	$ 547,409	$ 9,506

The following details the accrued exit and termination cost liability activity for the years ended December 31, 2021 and 2020 (in thousands):

	Exit Costs	Termination Costs
Balance at December 31, 2019	$ —	$ 4,692
Accrued severance costs	—	5,909
Accrued contract obligations	490,114	—
Accretion of discount	20,720	—
Payments	(17,291)	(9,147)
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

(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, 2019. 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, 2021	December 31, 2020	December 31, 2019
		(in thousands)	
Natural gas and oil properties:			
Properties subject to depletion	$ 9,338,236	$ 8,891,348	$ 9,345,557
Unproved properties	837,334	859,766	868,180
Total	10,175,570	9,751,114	10,213,737
Accumulated depreciation, depletion and amortization	(4,420,914)	(4,064,305)	(4,172,702)
Net capitalized costs	$ 5,754,656	$ 5,686,809	$ 6,041,035

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

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

	December 31, 2021	December 31, 2020	December 31, 2019
		(in thousands)	
Acquisitions			
Acreage purchases	$ 21,942	$ 26,166	$ 57,324
Development	381,753	369,093	666,984
Exploration:			
Drilling	6,329	7,709	—
Expense	22,048	31,376	35,117
Stock-based compensation expense	1,507	1,279	1,566
Gas gathering facilities:			
Development	3,402	3,694	3,583
Subtotal	436,981	439,317	764,574
Asset retirement obligations	18,634	2,610	11,193
Total costs incurred	$ 455,615	$ 441,927	$ 775,767

(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 2021, Netherland, Sewell & Associates, Inc., an independent petroleum consultant, conducted an audit of our 2021 reserves in Appalachia. These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2021, our consultant audited approximately 97% 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, 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. The average realized prices used at December 31, 2019 to estimate reserve information were $49.24 per barrel of oil, $17.32 per barrel of NGLs and $2.38 per mcf for gas using a benchmark (NYMEX) of $55.73 per barrel and $2.58 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, 2018	12,027,702	921,594	85,856	18,072,406
Revisions	33,122	57,311	(12,320)	303,068
Extensions, discoveries and additions	959,901	26,505	7,057	1,161,274
Property sales	(327,634)	(28,324)	(2,371)	(511,811)
Production	(578,114)	(38,850)	(3,690)	(833,354)
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
Proved developed reserves:				
December 31, 2019	6,486,211	535,007	34,369	9,902,468
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
Proved undeveloped reserves:				
December 31, 2019	5,628,766	403,229	40,163	8,289,115
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

[(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 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.

During 2019, we added approximately 1.2 Tcfe of proved reserves from drilling activities and evaluation of proved areas in the Marcellus Shale. Approximately 83% of the 2019 reserve additions are attributable to natural gas. Included in 2019 proved reserves is a total of 475.0 Mmbbls of ethane reserves (2,102 Bcfe) in the Marcellus Shale. Revisions of previous estimates of 303 Bcfe include positive performance revisions of 922.2 Bcfe which were partially offset by 601.3 Bcfe reclassified to unproved and negative pricing revisions of 17.8 Bcfe.

The following details the changes in proved undeveloped reserves for 2021 (Mmcfe):

Beginning proved undeveloped reserves at December 31, 2020	7,410,574
Undeveloped reserves transferred to developed	(1,199,544)
Revisions [(a)]	(393,561)
Extension and discoveries	1,540,128
Ending proved undeveloped reserves at December 31, 2021	7,357,597

(a) Includes 1.3 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.

During 2021, we spent approximately $361.3 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 $2.2 billion over the next five years. As of December 31, 2021, we have 21 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 2022. 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 2026.

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 2021, 2020 and 2019, 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, 2021	As of December 31, 2020
	(in thousands)	
Future cash inflows	$ 69,403,611	$ 35,820,758
Future costs:		
Production	(27,015,321)	(23,281,268)
Development [(a)]	(2,469,028)	(2,744,539)
Future net cash flows before income taxes	39,919,262	9,794,951
Future income tax expense	(8,146,832)	(1,240,011)
Total future net cash flows before 10% discount	31,772,430	8,554,940
10% annual discount	(19,287,204)	(5,708,618)
Standardized measure of discounted future net cash flows	$ 12,485,226	$ 2,846,322

[(a)] 2021 includes $308.5 million of undiscounted future asset retirement costs as of December 31, 2021, using current estimates of future abandonment costs.

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

	December 31, 2021	December 31, 2020	December 31, 2019
		(in thousands)	
Revisions of previous estimates:			
Changes in prices and production costs	$ 11,600,850	$ (4,868,371)	$ (6,560,107)
Revisions in quantities	577,737	(345,073)	(12,741)
Changes in future development and abandonment costs	(53,818)	107,899	104,585
Net change in income taxes	(2,248,161)	797,816	1,125,639
Accretion of discount	298,077	756,083	1,317,349
Additions to proved reserves from extensions, discoveries and improved recovery	1,423,510	280,441	552,710
Natural gas, NGLs and oil sales, net of production costs	(1,934,254)	(402,450)	(881,883)
Actual development costs incurred during the period	399,681	384,530	676,520
Sales of reserves in place	—	(394,125)	(688,937)
Timing and other	(424,718)	(99,001)	(120,156)
Net change for the year	9,638,904	(3,782,251)	(4,487,021)
Beginning of year	2,846,322	6,628,573	11,115,594
End of year	$ 12,485,226	$ 2,846,322	$ 6,628,573

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, 2021 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 quarter ended December 31, 2021 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 2022 Annual Meeting of Stockholders to be held in May 2022 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 2022 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 2022 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 2022 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 2022 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 5.00% Senior Notes due 2022 (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.7	Indenture dated September 16, 2016 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 4.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.8	Form of 5.00% Senior Notes due 2023 (incorporated by reference to Exhibit 4.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.9	Indenture dated September 16, 2016 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 4.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.10	Form of 5.875% Senior Notes due 2022 (incorporated by reference to Exhibit 4.4 to our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2017)
4.11	Indenture dated September 16, 2016 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 4.4 to our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.12	Form of 9.25% Senior Notes due 2026 (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 24, 2020)

4.13 Indenture dated January 24, 2020 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 24, 2020)

4.14 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)

4.15 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)

4.16 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)

4.17 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 Sixth Amended and Restated Credit Agreement, dated April 13, 2018 among Range Resources Corporation (as borrower), the institutions named therein as lenders and JPMorgan Chase Bank, N.A. as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on April 16, 2018)

10.02 First Amendment to the Sixth Amended and Restated Credit Agreement, dated as of October 18, 2019 among Range Resources Corporation (as borrowers) and JPMorgan Chase Bank, N.A. as Administrative Agent and the other lenders and agents party thereto (incorporated by reference to Exhibit 10.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on October 23, 2019)

10.03 Second Amendment to the Sixth Amended and Restated Credit Agreement, dated as of March 27, 2020 among Range Resources Corporation (as borrowers) and JPMorgan Chase Bank, N.A. as Administrative Agent and other lenders and agents party thereto (incorporated by reference to Exhibit 10.1 to our 8-K (File No. 001-12209) as filed with the SEC on April 1, 2020)

10.04 Amended and Restated Range Resources Corporation 2004 Deferred Compensation Plan for Directors and Select Employees effective December 31, 2008 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)

10.05 Amendment No. 1 to the Amended and Restated Range Resources Corporation 2004 Deferred Compensation Plan for Directors and Select Employees (incorporated by reference to Exhibit 10.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on April 25, 2018)

10.06 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)

10.07 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)

10.08 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)

10.09 Range Resources Corporation 2019 Equity – Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as field with the SEC on May 16, 2019

10.10 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)

10.11 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)

10.12 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)

10.13 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)

10.14	Purchase Agreement, dated January 5, 2021, 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 BofA Securities, Inc., as representative of the Initial Purchasers (incorporated by reference to Exhibit 10.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on January 5, 2021)
10.15	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*	Subsidiaries 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 22, 2022

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 22, 2022
/s/ MARK S. SCUCCHI **Mark S. Scucchi**	Senior Vice President and Chief Financial Officer (principal financial officer)	February 22, 2022
/s/ DORI A. GINN **Dori A. Ginn**	Senior Vice President, Controller and Principal Accounting Officer (principal accounting officer)	February 22, 2022
/s/ GREG G. MAXWELL **Greg G. Maxwell**	Chairman of the Board	February 22, 2022
/s/ BRENDA A. CLINE **Brenda A. Cline**	Director	February 22, 2022
/s/ MARGARET K. DORMAN **Margaret K. Dorman**	Director	February 22, 2022
/s/ JAMES M. FUNK **James M. Funk**	Director	February 22, 2022
/s/ STEVEN D. GRAY **Steven D. Gray**	Director	February 22, 2022
/s/ REGINAL W. SPILLER **Reginal W. Spiller**	Director	February 22, 2022

RANGE RESOURCES®